VISION FOR THE FUTURE ENERGY SYSTEM

National Electricity Market

AUSTRALIAN
ENERGY
COUNCIL

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1. Foreword from AEC Chair

Australia's energy system is undergoing the most significant transformation in its history. The task is to replace and modernise our aging energy system with cleaner and more advanced technology, while keeping energy reliable and affordable for households and businesses. Delivering on both is what will define the success of the transition.

In the past few years, energy has shifted from being a background utility, passively consumed, to front of mind for households and businesses. Australians are becoming more engaged, as they seek greater control over their energy use and costs, as well as their carbon footprint.

However, volatile global markets, geopolitical tensions and supply constraints are driving up fuel costs and raising sharper questions about security of energy supply. This is creating real and immediate cost pressures for Australians, against a backdrop of broader economic uncertainty.

In this context, the energy transition has never mattered more: building a cleaner and ultimately more affordable system that delivers lasting benefits for customers is critical to our future prosperity.

Today, we are at a point in the transition that can feel messy. Our ambition must be matched by delivery – across engineering, approvals, supply chains and construction. The choices made now will determine how quickly, reliably and cheaply we can deliver the transition and shape better outcomes for customers and the economy well beyond 2050.

The Energy2050 report sets out the AEC's ambitious vision for a 2050 energy system, and the priority areas of focus to get us there. Expectations are high and concerns are real, so we need to speak openly about the challenges ahead, and the opportunities in front of us.

Across the sector, progress is being made. Investment in renewable generation, storage and consumer energy resources continues to grow, and Australians are already helping reshape the system through electrification of their homes and cars. But progress hasn't come without challenges, and we need to be clear-eyed about what it will take to keep the system secure, reliable, and affordable as the generation mix changes.

This report sets out a practical agenda for the near term. It identifies the priority reforms and investment settings needed to keep momentum, and the partnerships industry and governments must build to advance the transition. That means building transmission, storage and firming on time, and providing the policy and market confidence that supports investment, so the system continues to reward reliability and flexibility at the lowest sustainable cost.

Above all, it reinforces the importance of keeping customers at the centre so that the most critical outcomes – affordable power, more control and choice, and trust in the system – are assured as we move forward.

The energy transition will not be linear. But with clear policy frameworks, disciplined execution and collaboration across industry and governments, we can lay strong foundations for Australia's energy future.

I commend this work to you and look forward to engaging with stakeholders as we seek to deliver a system in 2050 that genuinely works for all Australians

Frank Calabria
Chair, Australian Energy Council

2. Introduction

The Australian Energy Council's (AEC's) Energy2050 project aims to define what a successful transition to net zero looks like for Australian energy consumers, focusing on the core trilemma pillars of reliability, affordability, and sustainability.

Energy2050 is a vision for an energy system which provides affordable, reliable, clean energy for Australian families and businesses. This vision is broadly consistent with official 2050 projections and Energy2050 sets out how to achieve them.

The future potential is clear. Australia can harness our abundance of renewable resources to deliver low cost, reliable and clean energy for all. The technology we need to achieve this is here and now, and there is every reason to believe continued rapid advancements in clean energy technology and scale will create even more opportunities to deliver better energy for consumers where and when they need it.

We are at a critical juncture where much of our current system which has served us well for over half a century needs to be replaced, independent of Government policy. This creates challenges and costs as well as opportunities. The choices we make now will determine how quickly, reliably and cheaply we can transition to a better energy future.

Everyday energy consumers have been the champions of the transition to cleaner, cheaper energy. Their investments in rooftop solar have made Australia a global leader in distributed solar, and the competitive industry supporting them has delivered some of the lowest installed solar costs in the world. This consumer led investment is now providing cheap daytime energy for all users in many areas. We are now seeing consumers further take up the challenge through investments in batteries, electric vehicles and electrification.

The future will be increasingly decentralised. Consumers will be at the heart of a two-way system where they are increasingly exchanging services with each other.

In many ways it's time for the supply side to step up and deliver the transition at the wholesale level. Just as competition has delivered low cost solar for households, competition can deliver the lowest cost mix of renewable generation, shaping and firming services needed at all scales to deliver affordable, clean and reliable power to all consumers. Equally, competitive retail is the best framework for developing the innovative service offerings to meet diverse customer needs and to maximise their opportunities to be rewarded for supporting the grid where they are able to do so.

Electricity networks – the poles and wires – will continue to play the critical role of providing the platform for the transport and exchange of energy. This platform role will be more complex, enabling sharing of energy between consumers, as well as generation and storage at all scales. As natural monopolies, strong economic regulation and ring fencing of networks will remain essential to protect consumers and enable competition.

Across all these domains, affordability will remain a paramount consideration.

While the industry has plenty of work to do to deliver this future vision, we need governments and policymakers to partner with us to set the right frameworks for us to operate within. We've identified a set of priority actions to create and strengthen these frameworks:

Table 1: *Priority actions*

Theme	Actions	How this drives affordability
Establish clear, durable market and policy frameworks	Prioritise orderly coal exit pathways to: • Create space for firmed renewables • Improve investment signals for flexible supply - gas/hydro/long duration storage • Understand and procure competitively for system security • Early, place-based transition planning for affected regions	A stable market and policy environment will deliver lower wholesale prices than a chaotic one Competitive procurement for ESS will be lower cost
Timely transmission delivery	Reform the Integrated System Plan to better reflect the likely pace and costs associated with the transition Strong incentives for managing cost and avoiding delay	Transmission needs to be delivered on time to enable the generation and storage that will keep wholesale prices down
Develop new gas supply	Drive new supply by removing unnecessary barriers to approvals Domestic gas reservation set up on forward looking basis Foster development of opportunities for gas decarbonisation (e.g. CCS, biomethane, hydrogen) Support demand reduction via efficient electrification	Keeps gas prices as low as possible by incentivising new supply A focus on efficient electrification will deliver lower overall energy bills
Unlock more value for customers	Reward customers for supporting energy systems through their use of consumer energy resources Align network incentives and market signals to ensure CER can be coordinated at scale	Ensures customers are rewarded for using their own resources in the most efficient way, keeping costs low for all consumers, including those without these resources
Enable new retail models that benefit a diverse and changing customer base	Create regulatory and market frameworks that: • Foster the development of more innovative retail models (e.g. subscriptions, fixed-price offers and energy-as-a-service); and • Ensure sufficient flexibility to allow retailers to cater to a much more diverse customer base with different needs	Establishes the foundations of a customer-centric energy system that delivers energy at the lowest cost, tailored to different customer needs

Theme	Actions	How this drives affordability
Support large energy users	Enable growth industries through integrated resource planning Focus assistance for energy intensive businesses on helping them transition	Ensures large users can access competitively priced energy without imposing costs on other users
Streamline emissions reduction plans	Realign jurisdictional emissions targets to deliver a nationally consistent trajectory Drive reductions across all sectors Avoid technology targets	Enables least-cost abatement

The project focuses on Australia's two main energy systems: the National Electricity Market (NEM) which covers the eastern states and the Southwest Integrated System (SWIS) which serves Perth and the surrounding region in Western Australia. This paper is a comprehensive look at the NEM. A paper focussed on the SWIS, and a short form Energy2050 vision explainer have been published separately.

We have started by envisioning what the energy system could look like by 2050, particularly if net zero targets have been met (Section 3). This vision doesn't just entail the physical configuration of the future energy system, but also considers the ways consumers' energy needs and wants will be met, the roles of different parts of the supply chain and the underlying policy and regulatory framework that governs the interactions between different parties. From this starting point we envisage where we might be in 2035 as an indicative milestone to see if we are broadly on track for that 2050 vision. While this is not a prediction of the state of play in 2035, as a marker it seeks to provide a clear sense of what we need to aim for. While we are taking a positive outlook for 2050, an open and honest dialogue about the challenges and costs of the energy transition is required. Alongside the critical enablers that will help us get to Energy2050, we have included a snapshot of current issues and the risks and uncertainties that may prevent us achieving the vision.

Both the NEM and SWIS energy systems have been subject to detailed modelling and projections by the Australian Energy Market Operator (AEMO) and by governments. Energy2050 doesn't seek to present alternative modelling. Rather, the AEC and its members consider that the official modelling provides a sufficient framework for what, *qualitatively*, the two energy systems will look like in 2050. Broadly the 2050 energy systems are expected to entail an expanded transmission network, with large volumes of variable renewables and batteries complemented by gas, hydro (where practical), and long duration storage. Demand will have increased due to electrification of much of the transport sector and many of the energy services will still be delivered via natural gas, so this utility scale infrastructure will still be required even though there will be widespread deployment of consumer energy resources (CER) around the grid. Demand flexibility will play a significantly bigger role than it does today.

Projections such as AEMO's Integrated System Plan (ISP) do not represent a fixed blueprint for what the system will look like in 2050. The mix of the different resources is yet to be determined, and it is possible that additional technologies will play a role, but the above represents the most likely set of technologies. Importantly, Australia's coal fired plants, which were the mainstay of the NEM over many decades, are all expected to be closed by 2050, and no new coal plants are planned to be built.

The official models are just that – models. They don't tell us everything about what is required to deliver the transition and meet government emissions targets in the timeframe chosen. Energy 2050 seeks to provide context to these models, detailing the "how". This entails deeper consideration of a range of issues, which are summarised below and canvassed in greater detail in Sections 4 to 6. We have grouped these issues as follows:

- How best to deliver dynamic and flexible energy markets. This examines wholesale market design, the provision of essential system security services, delivering cost effective transmission infrastructure, and considers the role of gas; and
- How to deliver a consumer-centric energy system. This examines enabling consumer participation and sharing value, customising products and services, and developments at the distribution level.

There is also consideration of other key issues such as emissions and targets and large users. Box 1 sets out a brief description of each of the issues.

Box 1: *Key issues under consideration*

1. **Wholesale Market Design** - A key enabler for the Energy 2050 vision is the market and policy design required to underpin the investments needed.
2. **Essential system security services** - System security is critical to a stable electricity system. Energy2050 considers what is required to ensure efficient and adequate procurement of a range of security services as thermal assets exit the system.
3. **Transmission infrastructure** - The actual pace of change can vary from that set out in official models, and so we need to consider how to incorporate a better understanding of the barriers and delivery risks into planning processes, and to develop the policies and tools to reduce delays and costs.
4. **Role of gas** - There is a need to consider the options for gas used in gas-powered generation (GPG) and elsewhere in a "net zero" world - green hydrogen, biomethane, carbon capture and storage (CCS) or natural gas with offsets. Whatever the basis of the fuel, we need to consider how to ensure adequate supply as well as transport to end users, especially in the face of the impact of electrification on gas usage levels and patterns.
5. **CER** - Enabling participation and shared value - modelling assumes consumers display certain aggregate behaviours and a level of orchestrated CER, but not how consumers will agree to orchestration or decide how to manage their load, or how to ensure an equitable transition.
6. **Customised products and services** - looking at it from the other side, retailers and other service providers will need to develop very different products and services to give customers a reason to participate in orchestration and other offers. Consumer trust in their suppliers will have a large bearing on their willingness to take up innovative offers and allow load control-based approaches.
7. **Distribution networks** – including the drivers of deployment of community batteries, public electric vehicle (EV) charging infrastructure etc. and how the distribution network might evolve in other ways to meet consumers' requirements.
8. **Regional development** - closure of coal plants in one region may create employment and local economic difficulties and economic opportunities in other areas. The project will consider ways to manage this.
9. **Emissions and targets** - in the light of potential delays to the transition and a proliferation of sub-targets (jurisdictional targets, technology targets, etc.)
10. **Large users** – how to both support existing large users remain internationally competitive and to facilitate new large users connecting to the system without other users incurring costs.

Energy2050 has been developed with input from AEC members and external. Feedback was obtained through the following processes:

- Multiple member discussions including with member CEOs.
- A series of Future Energy Forums in five capital cities in late September and October 2025, to which we invited a mix of AEC members and external stakeholders. Each forum discussed two or three of the key themes.
- A White Paper was published and circulated to members and the external stakeholders who attended the Forums. Several recipients provided feedback on the White Paper.

Naturally there were a range of perspectives and views and it wasn't possible to accommodate all these views in one document.

3. Overarching 2050 Vision for Net Zero

The AEC's preliminary vision for 2050 is deliberately intended to be a positive, aspirational "light on the hill". We recognise it's a challenging goal to achieve, but its purpose is to drive action from today with a view to getting as close to these outcomes as possible, as a result of intentional policy design choices rather than by accident. The vision has two main components:

1. Dynamic and flexible energy markets; and,
2. Customer-centric energy systems.

Dynamic and Flexible Energy Markets

Dynamic and flexible energy markets are the driver of secure, reliable and efficient wholesale markets and other arrangements. Markets are very well placed to respond to evolving customer needs for generation, shaping and firming over time. We expect energy systems to be effectively decarbonised by 2050, so we'll no longer need signals for emissions reduction built in.

There will be an ongoing requirement to determine the least cost mix of reliable supply (including demand response) at any given time, so there will continue to be an important role for a spot market. Ideally the interaction of the spot market and the secondary contract market will be sufficient to reward generation and storage adequately while keeping energy affordable for users large and small. There may still be a role for additional revenue streams, most likely to provide a reserve of dispatchable capacity to keep the lights on through the most extreme renewable drought.

Some of that dispatchable capacity will be gas. This will need to be both decarbonised (whether via offsets, CCS or renewable gases) and delivered by a highly flexible production and transportation system, each of which could be provided in a range of different ways.

There will be an abundance of Essential System Services (ESS), mostly provided by inverter-based resources.

We will have completed a build-out of transmission and distribution networks to enable the hosting of large volumes of renewables and storage and network development will be returning to steady state, allowing a reversion to market-led expansion when required rather than centrally planned expansion. Since networks will be optimised using network support, load management and other tools alongside traditional augmentation approaches, an increase in demand may not require a significant new investment in poles and wires.

Customer-Centric Energy Systems

Customer-centric energy systems are designed so that users of all types and sizes can participate to the degree they want to in the energy system. This will be across the spectrum from passive consumers of grid electricity through to prosumers seeking to actively self-optimise across their consumption and production.

Participation will be frictionless, and most customers will have sufficient trust in service providers to allow them to orchestrate their Consumer Energy Resources (CER) on their behalf. Behind the scenes, service providers will be aggregating these resources to respond to signals for energy, system services and network support in a co-optimised manner designed to minimise overall system costs. All users will benefit from this cost minimisation process regardless of their level of participation or whether they have their own CER.

Wholesale and network requirements will be driven by customer need. This is the opposite of a traditional utility model where customers are obliged to take and pay for the services the utility decides the customer needs.

Distribution networks will have transitioned to being platform providers, enabling seamless consumption, export, trading and sharing of energy and demand response.

Households and small businesses will see their energy wallet shrink as they have transitioned from paying for three fuels (gas, electricity and petrol/diesel) to one (electricity) and can self-generate much of their own consumption. Large users will be able to access competitively priced power to enable them to compete internationally.

There is a lot of work to do in order to achieve these outcomes. Sections 4-6 set out the detailed changes of what needs to occur, including the critical enablers and the risks and challenges we will face along the way. We look forward to working with stakeholders and governments to see the Energy2050 vision delivered.

What the system could look like in 2050

The likely physical configuration of the system and the inherent uncertainties are described in the table below.

System element	Uncertainties
Low-cost solar and wind generation will take advantage of Australia's abundant solar and wind resources. This will be geographically dispersed relative to the historic system.	The mix of wind and utility scale solar is unclear. There's a chance another technology will take market share. The contribution of offshore vs onshore wind is also unclear. While offshore wind has potential to play an important role, its cost characteristics relative to onshore wind are currently a challenge yet to be overcome.
Renewable energy zones (REZs) are being developed across the system to tap into high-quality wind and solar areas using economies of scale and providing new employment opportunities.	The precise number and locations of REZs are unknown and will depend on the generation mix.
Transmission networks, existing and new, will connect the renewable energy from REZs through to consumers, bringing low-cost electrons to heavy industry, businesses and households.	There may be an opportunity for more hosting on the distribution networks. There may be merit in seeking to locate new industry closer to generation.
Firming and shaping technologies will smooth out the variations in renewable supply: batteries for everyday variations, and strategic pumped hydro energy storage (PHES) projects or other long duration energy storage (LDES) for longer-term and seasonal variations.	PHES are large, long lead time assets and it is unclear how many new projects will get built, especially as government support is likely to be critical. The Tasmanian system has scope to play a bigger role in supplying the NEM if the interconnection is there. If long duration batteries or other LDES become cost-effective this could crowd out PHES. The SWIS has less scope for hydro, so is likely to have a different mix of firming technologies
Gas-powered generation will provide necessary back up with critical power supply when it is needed, both for 'renewable droughts' of 'dark and still' conditions, or to meet peaks in consumer demand.	Gas may play a larger or smaller role than anticipated. If there is only a small role for gas, the gas network may struggle with the required flexibility.
Batteries, gas, pumped hydro energy storage (PHES) and other network investments will deliver essential system security (ESS) services to maintain grid security and stability.	There is a need to make a switch from relying on spinning machines for ESS to relying on inverters. How and when this occurs remains to be determined.

System element	Uncertainties
Rooftop solar and local batteries, connected to distribution networks both in front of and behind the meter, will generate consumers' own electricity, store it for when they need it, and supply the excess back to the grid	The scale of distributed resources is uncertain, as is how its owners will use it and whether they will allow their resources to be aggregated and orchestrated to optimise system needs or self-manage to meet their own needs.

While emissions reduction and the need to progressively replace old plant are key drivers of the transition to 2050, the system will continue to evolve even once net zero is reached. Demand patterns may change, and infrastructure will need replacing or upgrading. While new technology typically takes decades to reach widespread deployment, the further into the future we look, the more likely that a technology emerges that reshapes the system. So, while 2050 and net zero may be an important milestone we need market and policy settings that will continue to be fit for purpose beyond 2050.

4. Dynamic and Flexible Energy Markets (NEM)

Wholesale market design

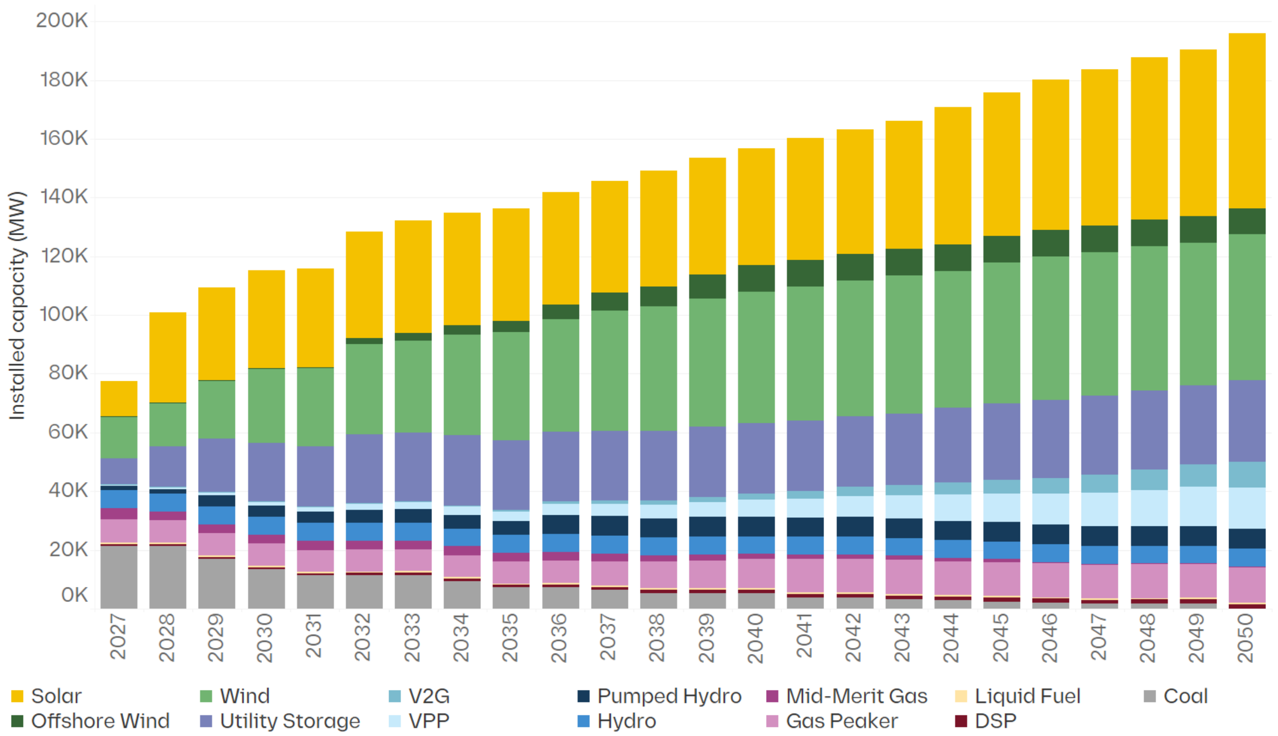
Target Future State (at around 2050)

Predicting the exact mix of energy assets out to 2050 is inherently uncertain, as what is an optimal mix today could shift as relative costs and revenues change over time. However, AEMO's Integrated System Plan (ISP) is a reasonable indicator. The energy mix in 2050 is likely to include a significant proportion of grid-scale variable renewable energy (VRE), such as wind and solar, a large amount of new firming capacity, new flexible gas-powered generation, along with the continued growth of rooftop solar and small-scale batteries. As an illustrative example, the draft 2026 ISP outlines the 2050 energy mix as including:

- Grid-scale VRE – 63 GW of solar and 57 GW of wind
- Utility scale dispatchable storage – 40 GW, including grid-scale batteries and pumped hydro
- GPG – 14 GW of flexible gas-powered generation
- Small scale resources 87 GW of rooftop solar and 27 GW of battery storage

Figure 1 *shows the change in the generation mix out to 2050. This was prepared by Endgame Analytics for the AEC and is based on achieving an ISP-like transition.*

Figure 1: ISP-like transition



Source: Endgame Analytics for the AEC, 2026

The investment to deliver this significant amount of new capacity, some of which will be required ahead of coal closures, could create a legacy of out-of-market financial support. A sustainable market for 2050 onwards requires reliability and other settings which allow investment in new capacity to recover its costs from market revenue streams. Market design will also need to accommodate a legacy of out-of-market payments in a way that avoids distorting post-transition investment and operational decisions.

By 2050, secondary contract markets must have evolved to deliver products that allow both generators and retailers to effectively hedge against potentially extreme events, including intra-day and seasonal volatility. This will require new types of contracts to account for the changing nature of generation and other services. Such markets will need to be deep and liquid to provide for a well- functioning and competitive energy market.

About one third of energy is likely to come from behind the meter resources such as rooftop solar, small-scale batteries and other consumer energy resources. Market design will need to have effectively integrated this into the wholesale market. This will require increased visibility of resources, as well as aggregation and scheduling into the market in a manner which is efficient but also offers consumers with a wide range of opportunities to access CER products and services. Consumers will have the choice of whether to participate in aggregation schemes.

Finally, to achieve this energy market transition will require good governance arrangements and coordination between market stakeholders, including jurisdictional governments, regulators and other market bodies.

Where do we need to be by 2035 to achieve the 2050 targets?

AEMO's draft 2026 ISP indicates that to meet Government emissions reduction targets, about two thirds of the current 21 GW of coal capacity would retire by 2034-35, and all by 2049.[1] Replacement capacity is needed in advance of these closures to ensure reliability is not compromised for energy consumers.

The required pace of the transition means that much of the required new investment could be out of the money, based purely on market revenues. Endgame Analytics modelling for the AEC indicates average wholesale prices of about $80-120/MWh, with significant variability depending on weather outcomes. Despite this, both firming and storage resources are forecast to need to be "made whole" (i.e. receive additional revenue streams) through policy options such as the proposed Electricity Services Entry Mechanism (ESEM) or the existing Capacity Investment Scheme (CIS). Endgame Analytics estimated the make-whole payment in an ISP-like transition for all new entrant renewable plants ranges from $12 billion–$40 billion out to 2040 depending on weather reference year and cost of capital assumptions (noting that wind trends to profitability and limited solar is built).

By 2035, the recommendations of the NEM Review Expert Panel (if adopted and implemented in a timely manner) will have been in operation for over five years, with deep experience operating the ESEM to attract investment, as well as improved liquidity through the market making features. Providing implementation of the ESEM is successful, this should remove the need for jurisdictional and other ad hoc interventions into the market. By contrast, if the recommendations are not implemented, then further consideration will need to be given as to how to deploy new resources at the required rate to meet emissions targets and coal exit timeframes.

The physical preconditions for coal exit to occur, including adequate alternative supply and reliability and security services, will need to be well known and communicated through AEMO planning processes. Timeframes must be regarded as credible in the market and updated promptly if necessary.

[1] Note that this is a slower closure rate than projected in the 2024 ISP, reflecting delays in the transition and a change in Queensland government policy.

While we consider it appropriate to remain optimistic about our ability to meet targets with the right policies in place, we must balance that against a realistic assessment about the physical, process and supply chain constraints that affect the pace of new deployment. Significant groundwork in ensuring adequate logistics (port, road capacity), skilling up the workforce, increasing the capacity for parallel approvals, etc. may be required to deliver a step change in the pace of deployment and it may take several years to get there. Global supply chain bottlenecks - for example for transformers, gas turbines, or Wind Turbine Installation Vessels (WTIVs), will likewise take some years to resolve.

Current State

Despite numerous recent reviews, the current state of wholesale markets policy reflects the limited progress to date in implementing reform. Further, the market has been subject to various interventions from both the Commonwealth and state jurisdictions, some of which have been at cross purposes.

The Commonwealth has an economy-wide emissions reduction target for Australia, while states have various targets, meaning there is no aligned position on exactly what the NEM is to achieve over various timeframes. The NEM review has suggested that state jurisdictions set electricity sector emissions reductions targets which would then feed through to the Australian Energy Market Commission (AEMC) target statement, and be used by an ESEM administrator to set the procurement trajectory for bulk VRE, shaping and firming services.

Most importantly, the significant investment in new generation to support emission reductions at the scale suggested by Australia’s national targets is not forthcoming at the required pace. There are a range of potential reasons for this, including recent government interventions, delays in delivering supporting infrastructure, the “missing money” problem[2], or uncertainty over future market dynamics such as coal closures.

There is also some misalignment between industry and governments on what generation mix is required to achieve emissions reductions targets. This has been compounded by some state governments keeping ageing coal plant open for stated security and reliability issues, on opaque terms.

The ESEM focusses on key services rather than technologies to help mitigate this misalignment.

Finally, affordability issues in the commercial and industrial sectors have led to a series of large but ad hoc government bailouts. This has picked winners by saving some industries but allowing others to exit. There is also uncertainty about how new load growth such as data centres will be met, and how best to forecast this new load growth. This will put further pressure on timely new investment into electricity supply and firming. These issues are further discussed in the Large Users section below.

Key risks and uncertainties

The above points indicate that there is a real risk of insufficient generation being delivered between now and 2035, particularly firming generation. This could lead to further policy reactions from governments such as market interventions, and the extension of ageing assets. Overall, this would create a more disorderly transition with affordability worse than could have otherwise been achieved.

[2] The "missing money" problem in Australia's National Electricity Market (NEM) refers to a gap between the revenue certain energy assets earn in the current market design and the amount needed to be commercially viable. This stifles investment, particularly in firming capacity like long-duration storage and gas-fired generation.

Late delivery of transmission is another key risk, which could delay the delivery of new generation and add further cost to end consumers. New transmission and generation infrastructure can also be controversial in regional areas and may risk further backlash on the purpose of the energy transition more generally.

Finally, essential system services are not well defined and understood. AEMO may require thermal plant to remain past its economic life to provide these services, again with resultant extra cost for consumers and potential delays to an orderly transition.

Critical enablers (to bridge the gap between current and future states)

All parties need to understand the market they are seeking to build into. This includes a common shared understanding of credible coal exit pathways[3]. The AEC strongly supports owner-led determination of closure dates, but we note that these may not be fully compatible with emissions targets. In that case, we will need a mechanism to determine the most efficient exit sequence and to ensure owners are kept whole. This timetable will need to be matched by a credible pathway for delivery of the requisite new investment in replacement supply (firmed renewables, flexible supply and system security services) in time for coal plant closure.

While clarity on coal exit pathways will create space for new firmed renewables, it won't be enough on its own. It is also crucial that a credible, NEM-wide, market-facing policy is implemented to support the required rate of investment in new generation and storage and to deliver the mix of technologies that will support reliability, security and emissions targets. This policy should function as a complement to, rather than a replacement for, the existing wholesale market.

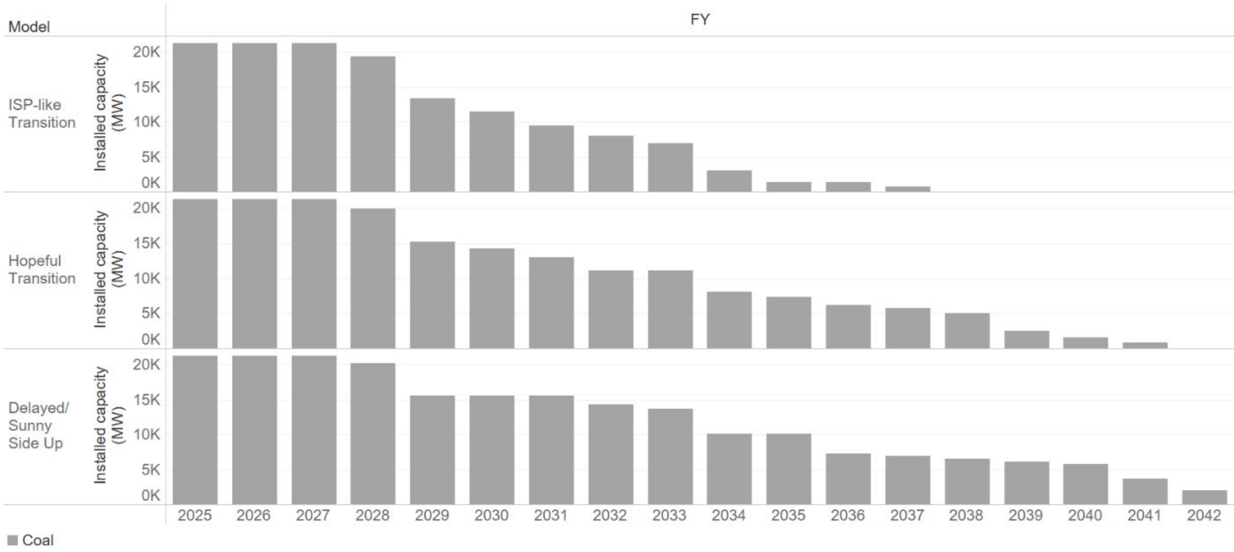
The starting point will be the recommendations of the NEM Review Expert Panel. These should be built upon in 2026 noting there is significant further work required to develop the recommendations. In particular, this includes the key proposal for an ESEM, which could help solve the tenor gap for new investment, especially for flexible firming technologies which to date have been excluded from support schemes such as the Large-scale Renewable Energy Target (LRET) and the CIS. The implementation should continue the industry-led process into contract design, with appropriate oversight from market bodies. Implementation should also include an "exit plan", to hold out the possibility of a return to fully market-led investment once the transition is largely achieved. Similarly, jurisdictional policies should be harmonised with a NEM-wide instrument, and wound down if they are no longer necessary.

Market design should adhere to a clear set of principles. This should include:

- Effective competition.
- Technology neutrality.
- Well defined service specification, including system security.
- Liquid secondary markets.
- Neutrality between existing and prospective market participants.
- Transparent investment timelines.
- Limited market intervention.

[3] While the focus is on coal, any such mechanism may need to be extended to cover other large thermal plant, such as some gas powered steam turbines.

Figure 2: *Coal capacity (ISP-like vs Endgame Analytics scenarios) by financial year*



Source: Endgame Analytics for the AEC, 2025

If jurisdictions wish to solve for greater than the Reliability Standard, they should do so out of the market and with taxpayer funding. This will require strict rules on when these resources can be called upon.

Jurisdictions should be encouraged to align their goals for electricity sector emissions reductions. This could be formalised in an AEMC target statement document to support NEM-wide trajectory setting and least cost abatement.

Priority Actions to Deliver

Prioritise orderly coal exit pathways to:

- Create space for firmed renewables.
- Improve investment signals for flexible supply - gas/hydro/long-duration storage.
- Understand and procure competitively for system security.
- Early, place-based transition planning for affected regions.

Essential system security (ESS) services

Target Future State (at around 2050)

ESS services are critical for securing and stabilising the electricity energy system. They encompass a range of functions, including frequency control, voltage regulation, minimum system load balancing, system strength, system restart and inertia.

The services required in the largely inverter-based system of 2050 are likely to be both qualitatively and quantitatively different from those required in a traditional synchronous generator-based system. Accordingly, it is difficult at this stage to determine which specific technologies will provide them. It's likely the most efficient pathway will entail service provision from the same assets which provide energy services rather than extensive deployment of standalone ESS providers.

At some point, we may come full circle and generators (including storage) will provide most of the necessary ESS as a matter of course. However, to get to that point some kind of market signal will need to have been in place during the transition to drive the investment decisions that will lead us to this point.

By 2050, the energy system should be stable, secure and resilient, enabled through:

- AEMO completing technical trials and learning necessary to inform what the system requires to be secure at very high levels of VRE;
- All relevant ESS services have been defined, unbundled and valued which has supported the required investment; and,
- A range of technologies playing a role, with inverter-based technologies expected to dominate (given synchronous generators will run at low capacity factors).

Where do we need to be by 2035 to achieve the 2050 targets?

In order to have a secure system at the lowest cost in 2035, and to be able to continue to do so through to 2050, we will need diversity of supply of ESS as well as a pathway to transitioning to inverter-based supply of most or all the necessary services. In 2035, ESS are most likely to be provided by a mixture of assets:

- Remaining thermal plant.
- Synchronous condensers.
- Gas-fired generation.
- Grid forming batteries.
- Pumped hydro generation.

Service definitions will need to be finalised allowing for the competitive procurement of ESS. All technologies providing ESS are compensated appropriately. Where assets are multi use, they can co optimise, and provide either energy or ESS services, as required.

Accountability and governance issues will need to have been resolved. The likely outcome is that AEMO's role is to set out the service definitions and technical specifications. AEMO has operationalised to allow for ESS to be dispatched as required by the energy system. All of this work has been completed ahead of key thermal plant retirement dates, meaning no further plant extensions are required to mitigate ESS risks emerging.

An innovation and trials framework will need to be in place to allow for the testing of new services, service providers and technologies. This will enable a pathway for successful service provision to be promptly integrated into ESS procurement and, in turn, drive more competitive service provision and lower costs for consumers over time.

Current state

Currently, most ESS categories have not been specified or holistically valued.[4] Therefore, no market incentives or price signals exist for most ESS categories. For ESS currently procured, the framework is fragmented, inflexible, opaque, and lacks adequate consequences for accountable parties. There is no strategic or coordinated NEM-wide plan for ESS. The current regulatory approach of relying on direct procurement of long lead time assets is reactive and shortsighted, as it neglects the need to provide signals for investment and development of non-network solutions. This creates a real risk that the NEM could fall short of ESS in the near future, and contributes to the prolonging of the life of old coal plants in cases where their owners have indicated a preference to close. ESS plays a vitally important role in enabling grid stability and reliability. Without credible and enduring investment signals for ESS, the energy transition cannot progress in an orderly, efficient or affordable way.

ESS provision still relies heavily on uncompensated provision by synchronous generators and directions, with only incremental requirements being rewarded. The exception is frequency control ancillary services, where the dynamism of markets is illustrated by a rapid shift over a few years to large scale batteries and aggregated resources becoming key providers, particularly in South Australia.

AEMO has been developing a transition plan and recently announced initiation of Type 2 trials (i.e. trials of new services) to industry.[5] These trials are an important step forward, and crucial to proving out the capabilities of a range of technologies. AEMO has recently submitted a rule change request with the AEMC seeking to enhance the provision of ESS as the energy system transitions, with similar concerns regarding the current arrangements.[6]

Transmission Network Service Providers (TNSPs) have procurement obligations to acquire services where there is a regional shortfall expected. This has to some degree paid off, noting that AEMO has reduced the number and cost of directions in South Australia following TNSP investment in synchronous condensers. However, the regulatory framework does not appear fit for purpose for driving efficient, timely and transparent service procurement.

Key risks and uncertainties

The key risks we have identified include:

- ESS are not adequately defined, with an ongoing reliance on unit commitments to support system security.
- Necessary investment is not forthcoming, as there is no market-based incentive to make the investment.
- Over reliance on TNSP network solutions, at greater cost and risk to consumers, due to the operation of network regulatory frameworks.

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[4] We acknowledge that there are various market arrangements for some of the ESS categories, such as the eight Frequency Control Ancillary Service (FCAS) markets and frequency performance payments. These services would not be the subject of procurement through the ESEM.

[5] https://www.aemo.com.au/newsroom/news-updates/aemo-progressing-transitional-system-security-services

[6] https://www.aemc.gov.au/sites/default/files/2025-11/New%20rule%20change%20proposal%20-%20AEMO%20-%20Efficient%20and%20timely%20management%20of%20system%20security%20needs%20through%20the%20energy%20transition.pdf, p.6

- Delayed delivery of network solutions acting as a barrier to thermal plant exit, delaying the energy transition, again at greater cost to consumers.

Critical enablers (to bridge the gap between current and future states)

ESS procurement needs to occur in a coordinated manner. This could be done by elevating ESS contracts to the same level as those for bulk energy, shaping, and firming services currently being contemplated by the Expert Panel, while accommodating the unique characteristics of ESS.

This would involve (in turn):

- Developing specifications and standards for relevant ESS.
- Creating long-term standardised contracts for categories of ESS.
- 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.

This approach would help provide investment certainty, reduce reliance on costly, ad hoc interventions, and minimise incremental costs of ESS provision. ESS contracts will also require regular review and refinement. Given the rapid evolution of technologies and system needs, an industry led co-design process is recommended.

It is also vitally important that there are greater opportunities to test new technology to improve the range of service providers and drive lower cost solutions. This would also send the right signal to encourage Original Equipment Manufacturers (OEMs), technology providers, and developers to innovate and invest in new technology/solutions.

To enable developers to identify or develop possible ESS solutions, ESS needs to be defined and detailed standard/specification developed. The standard/specification quantifies the physical requirements of the ESS service and is what the engineers require to determine whether a particular piece (or combination of) technology could physically deliver the required ESS. Defining the ESS and providing a standard/specification for the ESS that are relevant to this proposal is a critical first step. The development of ESS standards should be undertaken via a co-design process between AEMO and industry.

In the meantime, where services have been sufficiently defined to allow TNSP procurement of incremental service provision, such as inertia and system strength, the growing scarcity of these services should be recognised by developing a compensation mechanism for *all* participants providing these services.

Transmission infrastructure

Target Future State (at around 2050)

By 2050 the physical footprint of the NEM will have been expanded out to allow the connection of a significant rollout of new renewables and storage. This will involve the creation of a number of REZs[7] where renewables are clustered together and connected into the backbone of the grid, which will in turn need strengthening.

[7] The draft 2026 ISP projects 44 potential new REZs, but the number and configuration may evolve over time.

Key energy transmission projects will have been built on time and on budget. Transmission infrastructure is scoped and sized to meet the defined needs of the energy system on a NEM-wide basis and at least cost to consumers. There will be an established process to assess which projects make the most cost-effective contribution to energy system reliability, with project timing prioritised accordingly.

Social licence to build infrastructure projects is gained and maintained. Communities fully share in the benefits of hosting infrastructure, as the benefits from hosting are well understood and communities are confident they can forge genuine mutually beneficial partnerships with infrastructure developers.

Ultimately, the system will reach a 'steady state' where expansion is only required to meet future incremental load growth.

Where do we need to be by 2035 to achieve the 2050 targets?

To affordably deliver the required transmission infrastructure needed for 2050, infrastructure build out rates will need to be business as usual by 2035, with real world experience informing efficient planning decisions. To achieve this, we would expect that by this stage:

- Planning processes across jurisdictions and AEMO have been significantly improved and reflect actual build rates and plant retirements. Planning processes will also be harmonised (or harmonisation is in train) to drive efficient planning decisions NEM-wide. There is also co-optimisation between transmission hosting and distribution-level hosting.
- Thermal plant exit is occurring on predictable timeframes, with transparency of the suite of generation services required to support reliability and system security on their exit.
- A national agency is established with responsibility to monitor for supply chain constraints and approval delays and has powers to solve these.
- A number of large current projects with approval are operational, including the first 11 REZs, Marinus Link stage 1, HumeLink, CopperString, VNI West and the Western renewables link; with other projects under development.

Current State

Currently, AEMO's ISP describes what needs to be built to support the emissions reduction policies of the states and Commonwealth. Most of the state policies are highly prescriptive in terms of transmission build. For example, state based renewable energy zones and some downstream upgrades as well. It is also required to include specific jurisdictional technology targets, whether least cost or not. Overall, this is best characterised as a net benefits modelling exercise with constraints, limitations and assumptions.

The cost and timing of new projects is also a significant issue. While the ISP model, if allowed to run, would pick the optimal timing based on costs and market benefits, most of the transmission build is a constraint and AEMO uses the dates provided by the states. Supply chain issues, many of which are international in nature, have driven higher cost and delay. This includes both transmission infrastructure and key grid security equipment like synchronous condensers and gas turbines. Lead times have increased from two years to five years in some cases.

Further, delayed delivery of key infrastructure does not carry a financial penalty, other than delayed timing of Regulatory Asset Base (RAB) expansion.

Social licence issues are widespread, and is compounded by the lack of bipartisanship on the overall net zero goal. There is a spectrum of attitudes across regional communities, ranging from deep resistance to early-stage projects, such as the Western Renewables Link, to positive partnerships, such as the Wimmera

Southern Mallee Regional Energy Collaboration[8]. This latter example could be a blueprint for other regional communities - for both network and generation developments. Additionally, there has been a focus in recent years in empowering First Nations communities to benefit from energy projects on Country.

There is an ongoing focus on improving community consultation on new energy infrastructure, including community engagement requirements embedded into the access regime and planning approvals processes, developer best practice guidelines and a Developer Rating Scheme. It is too soon to say, however, if these are sufficient to overcome the barriers.

Key risks and uncertainties

The implementation of such a significant scale of new infrastructure projects entails several key risks:

- Late delivery of transmission infrastructure delays the energy transition and increases costs to consumers as it inhibits the ability of wind to enter the market, meaning higher cost generation is dispatched for the period of delay. We note the AEMC recently reported that delays to wind and transmission projects could increase household electricity prices by as much as 20%.[9]
- Social licence for transmission projects is not attained, contributing to late delivery.
- Transmission cost blowouts negatively impact affordability.
- The opportunity for efficient development of projects outside REZs is overlooked.
- Multiple planning processes risk confusion about priorities, costs and timeframes.

Critical enablers (to bridge the gap between current and future states)

A range of reforms could be considered to help reduce the key risks identified above. Firstly, the long-term infrastructure planning process could be improved with AEMO's ISP evolved into a more practical plan about how to meet government targets. This could be in the form of scenario analysis showing alternate pathways that are more realistic. Further details of this approach are presented in **Error! Reference source not found.** below.

The network regulatory framework could be reformed, and incentives strengthened to:

- Promote timely delivery of key infrastructure projects, which could include some form of financial penalties for late delivery or accountability for the delivery of the market benefits on which the investment case of a project was based.
- Ensure networks are properly incentivised to consider both network and non-network solutions to meet reliability and security responsibilities.

Community views on infrastructure projects that affect their region should be better integrated into the planning process. Instead of a top-down process driven by government and market bodies, more emphasis could be placed on how benefits could be shared with local communities.

Box 1: How to evolve the ISP into a practical transition plan

[8] https://wsm.org.au/projects-and-programs/energy-transition-local-research/

[9] https://www.aemc.gov.au/sites/default/files/2025-12/Price%20Trends%202025_Report%20%281%29.pdf, slides 15 and 17

A practical transition plan would require:

- AEMO clearly communicating that the ISP is not a prediction of what will happen, but rather a projection of what transmission build is needed to support a central scenario, consistent with jurisdictional policies.
- ISP modelling a central scenario based on the states and Commonwealth achieving their emissions, transmission build or technology targets.
- Other scenarios can then be developed, based on alternate pathways. This would, in practice, allow AEMO to model any emissions trajectory (e.g. slower or faster than Government targets), or more realistic sensitivities to stress test the central scenario, compared to the status quo. It would also enable an energy system affordability scenario to be created to help policy makers decision making.
- Model outcomes based on current policy settings, as distinct from targets. For example, projects that have been awarded a CIS contract would be included, but offshore wind would not (as there is currently no policy mechanism to deliver the targets). This would provide a useful illustration of where additional policies may be required to meet the targets. This approach would be similar to the International Energy Agency's (IEA) global scale modelling which uses "current policies" and "stated policies" (i.e. targets) as two of its main scenarios.
- Relaxing jurisdictional constraints to allow AEMO to generate a NEM wide view on a least cost transition for a given emissions trajectory, while allowing for consideration of the relative costs of different trajectories.
- This plan would incorporate real-world costings, and delivery timeframes, with AEMO required to regularly update these based on the latest market data.

Priority Actions to Deliver

- Reform the Integrated System Plan to better reflect the likely pace and costs associated with the transition
- Strong incentives for managing cost and avoiding delay

Role of gas

Target Future State (at around 2050)

Reaching net zero implies minimal consumption of unabated natural gas by 2050 however projections from AEMO and other authoritative sources indicate there will still be significant consumption of gas fuels. To reconcile this, the target future state would be that gas demand is met through gas peaking to firm variable renewable generation and an increase in the use of biomethane, green hydrogen (collectively, "renewable gas") and CCS. Some offsets are likely to be used.

There will be very little household and small business gas use, (30PJ[10], down from around 195PJ currently) as consumers will have progressively electrified their space heating, hot water and cooking needs. This will strand large parts of the reticulated gas network, so a framework will need to be in place well before 2050 to support these assets and ensure gas supply is maintained to the remaining customers. Plausibly all small customers could be off reticulated gas, but some users may find it hard to switch, including renters, apartment dwellers with shared gas appliances and low income households with limited access to capital. Accordingly, actual outcomes will depend on policy choices by governments. Some networks and governments continue to see a long-term future for reticulated gas based on a switch to renewable gases, for example South Australia.

Industrial gas use will only decline slowly to 2050 (220PJ, down from 230PJ currently, and assuming no major facility closure). The limited change reflects a lack of evidence that industrial users can or will switch to lower emissions alternatives, although larger users will be impacted by safeguard baseline decline.

The NEM will still rely on GPG for firming and to fill in for renewable droughts. During periods when GPG gas demand is high, the gas network including pipelines and storage will need to be capable of very flexible supply (90PJ annually, but up to 3,000TJ on a peak day, compared to 100-150PJ pa in recent years, and peak demand of c. 1,200TJ).

Gas transport and storage costs will be higher than today due to this divergence between total consumption and peak demand. GPG will need to recover these costs as well as their own capital costs, and potentially higher commodity costs for renewable gases. Consequently, there will need to be a revenue adequacy mechanism for GPG (potentially applicable to other similar technologies). This could take many forms including an energy-only market with high enough reliability settings and appropriate secondary contracts.

Where do we need to be by 2035 to achieve the 2050 targets?

To be on track for net zero by 2050, renewable gases and/or CCS will need to start being deployed at scale by 2035.

In the meantime, new natural gas supply will need to be online and contributing to domestic supply volumes.

Targeted investment in gas infrastructure to meet GPG winter peak day demand will be well underway (AEMO expects the ramp up in peak day demand to start in the early 2030s).

At the same time, the impact of small customer electrification on reticulated gas networks will be material. Policy enablers to manage this decline will need to be implemented.

[10] This and other gas volumes cited are illustrative only, and are derived from extending the trend lines in AEMO's 2025 GSOO.

Current State

Gas use is steadily declining due to a combination of factors, including higher prices, industrial closures, and residential electrification (520PJ in 2024). Despite this there are projected gaps in supply as existing fields decline, so new supply is required before 2030 (both to meet peak day requirements and to meet overall demand). Wholesale gas prices are broadly linked to international benchmarks, due to the startup of an LNG export industry around a decade ago. Wholesale gas prices are in turn one of the major drivers of the electricity wholesale price.

Transmission pipelines are not subject to access arrangements where regulators determine price, while distribution pipelines are largely regulated. The latter are now seeking to raise prices so they can recover their sunk capital faster, though this is not likely to be sufficient to avoid asset stranding.

CCS, green hydrogen and biomethane are all technically possible, but not considered commercial at current costs and are yet to be widely deployed.

Key risks and uncertainties

Electrification is a choice for users and even for households where lower total energy bills can be expected, there may be financial and non-financial barriers that slow it down. Existing policy support is largely through white certificate schemes, which pass their costs onto all energy users. This may not be sustainable if affordability concerns continue to grow.

Economically viable alternatives to natural gas will need to be found for industrial users. Whether renewable gases such as biomethane and green hydrogen, or carbon capture and storage at large gas consumption sites become economically viable remains to be seen. Non-gas alternatives are being piloted in some industries internationally, but there is no clear pathway to widespread commercial viability. While declining safeguard baselines creates an incentive to decarbonise industrial processes, it could instead drive closure where an alternative energy source/process cannot be commercially deployed in time. Greenfields development of new facilities may be more economic than retrofitting in some cases.

If renewables deployment picks up, there could be scope for a green hydrogen sector based on utilising surplus renewable electricity, but this will need to be weighed against the costs of a lower utilisation rate for electrolysers.

On balance, the main challenges for the next 20 years appear to be how investors manage regulatory uncertainty and ensuring sufficient supply to meet demand (rather than managing the consequences of very rapid demand decline). New supply remains challenging in the context of a broader drive to decarbonise and jurisdictional policies that limit the scope for new development.

Additionally, the required flows of gas may change. If new supply continues to be concentrated in the north, then some of this gas will need to be able to flow south to meet demand in southern states. Investment to facilitate this is starting to occur, but there remains a question as to whether there will be enough certainty to underpin further investment in enabling infrastructure, especially if northern gas ends up competing against imports into southern state terminals.

If maintaining a gas network post-transition just to supply gas peaking capacity on rare occasions appears unviable, we may have to consider alternatives such as diesel or potentially more longer-term storage – though it would be valuable to have at least one external fuel source contributing to electricity reliability (see **Box 2** below). If gas is still playing a bigger role – for example longer-term seasonal shifting to meet winter supply/demand gaps, then a functioning gas network that can recover its costs remains essential.

The export market is four times the size of the domestic market, and global gas demand is expected to remain strong for many years.

Additionally, the level of regulatory intervention in the east coast gas market could distort efficient price signals. This includes:

- AEMO's expanding roster of intervention powers which could create perceptions that the market will not be permitted to function and could distort price signals, undermine investment certainty, and disrupt contracting.
- Non-transparent deals between government under the heads of agreement between government and producers.
- Price controls.
- Increasing and burdensome transparency requirements on downstream participants which significantly complicate buying and selling gas in the East Coast Gas System (ECGS).

Some of these will be removed or reduced as part of the overhaul of policy expected to follow the release of the Gas Market Review later in 2026. But it's also expected to see the introduction of an east coast gas reservation policy. While this could deliver positive outcomes for domestic users, and is intended to provide clarity to the exporters on their future domestic supply obligations, it will need to be closely monitored to ensure it does not unduly distort efficient market outcomes.

Critical enablers (to bridge the gap between current and future states)

New supply will need to be facilitated. At a minimum this entails removing unnecessary barriers to approvals. Depending on how aggressive emissions reduction policies become, governments may need to contribute to mitigating stranded asset risk.

Additional supply is needed in the domestic market. This will require the timely development of new fields, which should help deliver affordable gas into the domestic market. Producers should still be able to recover their costs and make a profit. Arbitrary moratoria and other regulatory barriers should be removed. Imports may also play a role. Domestic supply could also be bolstered if the Government's proposed domestic gas reservation policy is successfully implemented.

Renewable gases or CCS appear unlikely to scale without some government support. The challenge is to develop supporting policies to help bridge the commercialisation "valley of death" rather than simply waste public money on white elephants. A renewable gas target could stimulate private investment without government needing to try to pick winners.

A carbon price, though widely considered politically unviable, would also provide a clear policy signal to help drive the switch to lower/zero carbon alternatives to natural gas. Conversely, the application of individual Safeguard Mechanism baselines to the electricity sector could disincentivise GPG before alternative fuels are commercially available.

Infrastructure regulatory frameworks will have to evolve to simultaneously support specific new investments in storage or transportation, while managing stranded assets in other parts of the network. To date most transmission and storage investment has been market driven.

There may be a greater role for planning and regulated investment to solve challenges such as building in flexibility, facilitating north-south flows and ensuring winter peaks are met. While the market always seems to solve winter shortfalls, there is no transparent pathway to see it solved year on year.

Some government support for industrial decarbonisation appears inevitable and is already occurring (e.g. Whyalla Steelworks in South Australia). Support for energy intensive industries should be oriented to helping them transition to lower emissions operations rather than simply business as usual activity.

Small users have (in most circumstances) cost-effective alternatives to gas, but may be inhibited by various barriers to switching. There will continue to be a role for some enabling policy in this area, and efficient electrification will be part of the solution of balancing gas supply and demand.

Box 2: Firming the last MW

An ongoing role for GPG in the system is predicated on having a gas transportation system that is flexible enough to deliver large volumes of gas on a handful of peak days and potentially very little at other times. If there is little role for gas in daily firming (because there is sufficient storage or demand flexibility for example), and if there are few other gas users (if electrification pathways for industrial users improve), then it may prove inefficiently expensive to maintain a gas network primarily for occasional GPG use. If this scenario appears likely to emerge before 2050, then we will need to consider alternative ways to keep the power system going through renewable droughts. Options include:

Diesel – As an energy-dense liquid, diesel can be transported by truck and is easier to store on site than natural gas. While diesel would usually be considered a more expensive peaking option than natural gas, under this scenario, it could prove better value as it doesn't require its own transportation network. From an emissions perspective, the amounts consumed would be relatively low and biodiesel may be an option.

LDES – while having an independent fuel vector is somewhat desirable from a system resilience perspective, we may able to achieve reliability with LDES, providing we have enough of it to cover an extended renewable drought. Obvious options for the LDES technology are pumped hydro and long duration batteries, though there are other emerging technologies. The key to success is to ensure that sufficient capacity is held in reserve, which constrains the storage operator from maximising their opportunities in diurnal or other short-term storage situations.

Green hydrogen – as hydrogen is less dense than natural gas, it is more challenging to store and transport. So, this is only likely to be a viable option if there is an extensive hydrogen network being set up for industrial heat in any case. Assuming hydrogen production is via electrolysis, then it is effectively another form of storage rather than an independent fuel source.

Regardless of which technologies prove the most cost effective, critically we need to find ways to reward plant for ensuring it is available in rare cases (and potentially only then). Ideally the market will find a way to reward such plants, but this will depend on the reliability settings. An alternative may be to establish a reserves procurement process, whether centralised or decentralised, separate from the spot market.

Priority Actions to Deliver

- Drive new supply by removing unnecessary barriers to approvals.
- Domestic gas reservation set up on forward looking basis.
- Foster development of opportunities for gas decarbonisation (for example, carbon capture and storage, biomethane, and hydrogen).
- Support demand reduction via efficient electrification.

5. Customer - Centric Energy Systems (NEM)

Consumer Energy Resources - Enabling Participation and Shared Value

Target Future State (at around 2050)

By 2050, consumers co-create value through their homes, businesses, communities, and data. Behind the scenes, retailers and other aggregators orchestrate complexity - delivering simplicity, reliability, and trust. Consumers can choose how deeply they engage, from a simple, low-cost, reliable supply to full CER participation. People are active participants in the energy transition, not simply passive recipients of supply.

CER is predominantly made up of 'supported services' (instead of consumers managing their own solar, batteries, EV charging, or flexible demand, the retailer provides a packaged, managed service that optimises these assets automatically). There is a high level of trust in retailers that they are maximising CER value for customers (with low effort from customers). Technology enables retailers to maximise the value of the service – "energy as a service" is a common platform.

As an illustrative example of the scale of CER and its integration into the system, AEMO's 2025 ISP Inputs, Assumptions and Scenarios Report Step Change scenario forecasts the following by 2050:

- Greater adoption of energy efficiency measures (around 80TWh avoided energy annually).
- PV penetration on houses and semi-detached dwellings is projected to reach 56%, or around 80 GW.
- Larger-scale PV (commercial and industrial) will grow more modestly as costs decline to reach just under 15 GW.
- Distributed battery capacity across the NEM and WEM is forecast to reach around 30 GW, including coordinated and uncoordinated systems.
- Aggregated VPP capacity of 15 GW. AEMO includes some community and neighbourhood batteries within its "large commercial" battery category, but they are not separately identified.
- Between 16 million and 30 million EVs (64%–95% of all vehicles). The pace of adoption will determine both the system's demand-response potential and progress toward net-zero goals.

Where do we need to be by 2035 to achieve the 2050 targets?

To achieve the 2050 vision, the 2035 energy landscape will need to shift from the current phase of rapid technology uptake to optimisation and inclusion. This will see households and businesses becoming central actors in flexible, value-sharing systems, driving affordability, reliability, and emissions reduction.

We will need to support participation evolution, as many consumers with CER transition from passive users to active market participants. Retailers and aggregators will need to enable their customers to provide grid and community services, such as supporting local reliability, sharing energy within neighbourhoods, and contributing to resilience, while maintaining simplicity, trust, and choice.

Efficiency and equity: With most easy gains achieved, future efficiency improvements will depend on upgrading older housing and rental properties. These investments will need to deliver sustained bill savings, comfort, and demand moderation to underpin long-term cost stability.

Solar maturity and inclusion: Rooftop saturation will result in a slowing rate of new installations, but new growth can arise from upgrading early, undersized systems and expanding access for renters, apartment dwellers, and commercial buildings. Policy and market design will need to focus on interoperability and optimising the use of existing and distributed energy resources — ensuring they are used efficiently, flexibly, and in ways that deliver the most value to consumers and the grid.

Storage and VPPs: interoperability and consumer protections will need to mature to maintain rapid uptake of battery systems. Second-life EV batteries can lower costs, making household and community storage more accessible. VPPs will need to become a mainstream mechanism for flexible demand and local reliability, coordinated through trusted retail platforms.

Emerging modelling and industry roadmaps indicate that by 2035, Australia's EV fleet could transition from a purely transport asset to a dual-purpose asset; for both mobility and energy storage. With smart charging and bidirectional integration (V2G), EVs offer the potential to manage peaks, stabilise the grid, and create new consumer value streams - provided the necessary hardware, business models, standards and regulatory frameworks are scaled.

Current state

The shift from passive consumer to active participant is underway but it remains early-stage. Efficiency improvements are progressing but are not yet central to system outcomes.

Over 4 million households now have rooftop PV, yet orchestration and flexible-demand value capture remain limited. Distributed battery capacity is growing quickly but from a low base relative to the forecast of around 30 GW 2050. VPP capacity is nascent compared with AEMO's 15 GW target, though good foundations are being laid. EV adoption is accelerating but still far from the projected 64%–95% fleet penetration.

Fragmented regulation, inconsistent CER standards, and varying connection, metering, and tariff approaches continue to constrain market development.

Key risks and uncertainties

A number of risks and uncertainties could slow or distort the development of CER markets and prevent consumers from realising their full value. One major uncertainty is the future trajectory of technology costs. If the costs of rooftop PV, distributed batteries, or electric vehicles do not fall as quickly as expected, the pace of consumer adoption may slow, reducing the volume of flexible demand and storage available to support the system. The extent to which consumers have the capacity to afford CER is also unclear.

Consumer participation is another core risk. Even where technology is available, consumers may not engage with CER, VPPs, energy efficiency programs, or flexible demand services at the levels modelled. Low participation would limit both consumer value and system benefits.

The pace and consistency of policy and market reform also presents a significant uncertainty. Slow or fragmented reforms, particularly those relating to CER standards, data frameworks, flexible demand markets, and net-zero policies, could undermine investment confidence and increase costs.

At the system level, Australia may struggle to coordinate and integrate millions of CER assets effectively. If orchestration platforms, interoperability standards, or operational roles are poorly defined, the system may not be able to harness CER's full potential for reliability, resilience, and affordability.

Supply chain and workforce constraints also pose risks. The availability of equipment, skilled labour, and essential materials may not keep pace with rising demand, delaying CER deployment and increasing costs for consumers.

Consumer trust remains a central and persistent challenge. If trust in retailers does not improve meaningfully, consumers may be reluctant to hand over control of their assets or participate in orchestration programs, even where benefits are clear.

Over-regulation adds another risk. Highly prescriptive requirements—such as certain connection rules or schemes like Solar Sharer – may discourage innovation, raise transaction costs, or limit retailers' and aggregators' ability to develop new service models.

There are also important boundary issues between retailers and distributors. If distribution businesses seek to use their regulated asset base to deploy CER, it could create competitive distortions, reduce innovation, and blur accountability for consumer outcomes.

Finally, Australia may not roll out EV charging infrastructure quickly enough to support mass electrification. A slow or uneven build-out would limit EV uptake and hinder the ability of electric vehicles to operate as flexible energy resources.

Critical enablers (to bridge the gap between current and future states)

We need to reward CER appropriately for supporting the system. We also need to establish common standards, monitoring and fit-for-purpose regulation to maximise the opportunities for consumers to access those rewards. Through consultation, the AEC has identified the following options:

- Conduct an urgent review of CER optimisation barriers — examining whether regulation, market design, or network arrangements are constraining consumers' ability to gain full value from their assets and how consumers can participate safely and profitably in markets for flexibility, capacity, and resilience services. This recommendation is about fixing value extraction and participation now, whereas DCCEEW's CER Roadmap is about building the enabling architecture over time. They operate at different depths, speeds, and levels of market accountability.
- Ensure retailers can access all sources of value across the cost stack to design compelling orchestration offers. Require networks to provide retailers with flexibility incentives or price signals. Retailers can then package upstream costs and automate tariff optimisation for customers. Retailers can make complex tariffs simple by using machines to respond on behalf of their customers.
- Establish common data standards and governance to build trust, interoperability, and efficiency. Harmonised national frameworks will enable seamless, low-transaction-cost CER markets.
- Continue work on the development of a regulated framework for customer agents who act on behalf of customers to optimise CER assets and manage participation safely and efficiently.
- Track and report uptake of consumer-focused CER products and services. Publish insights on who participates, who benefits, and where gaps remain.
- Retailers building customer trust requires transparency of value (affordability work; products; proactivity and innovation).
- Principles-based regulation may encourage innovation if it is accompanied by removal of existing prescription. This is likely a medium to longer term consideration.
- CER and distribution system operator (DSO) interoperability, harmonised standards.
- Charging infrastructure (shared and individual) rolled out smoothly.

The goal is that by 2050, consumers experience one seamless energy relationship, even as networks, market operators, and service providers collaborate behind the scenes. Retailers remain the primary customer interface, responsible for simplicity, fairness, and dependability. To fulfil this role, the retailer model must evolve further into energy-service and flexibility management, integrating CER into wholesale and ancillary markets.

No single provider can meet all customer needs. Success depends on open collaboration across retailers, networks, aggregators, governments, and communities.

Priority Actions to Deliver

- Reward customers for supporting the energy systems through their use of consumer energy resources.
- Align network incentives and market signals to ensure CER can be coordinated at scale.

Customised products and services

Target Future State (at around 2050)

Electrification will drive significant increases both in overall load and in the potential for load volatility. As an indicator, by 2049-50, 141 terawatt hours (TWh) of new electricity consumption, is forecast: that's around three quarters of existing NEM plus SWIS demand. Road transport electrification is forecast to grow materially, to 69 TWh by 2049-50.

By 2050, retailers will manage volatility behind the scenes, providing price stability and predictability. Retailers will be CER coordinators and orchestrators with the competitive market continuing to put downward pressure on prices.

There will be a move to fixed, simple pricing, with less variability with consumption, for those who want simplicity, including the non-engaged. CER creates value from trading assets, enabling a partial rebate of the fixed price. Energy companies will operate like insurance companies – consumers will purchase a product that ensures security of supply.

Consumers will increasingly shift from non-CER or passive participation to medium/high CER engagement, and being actively rewarded for flexibility through dynamic pricing and/or automated optimisation. Passive consumers will retain access to reasonable prices with low engagement and low risk exposure via multi-year contracts, subscription plans, etc. The system operates to share value between those who participate to those who are less engaged and need more support.

Consumers will have access to excellent, dependable energy services with all their energy needs (like electricity for homes, heating, cooling, EV charging, etc.) consistently met, whether via their CER or a reliable and resilient grid.

Energy becomes an adaptive service, which is tailored, transparent, and empathetic and where choice for the capable and care for the vulnerable coexist. Customised energy services combine flexible products, inclusive design, and protection from market risk.

Where do we need to be by 2035 to achieve the 2050 targets?

In order to achieve the 2050 vision of customised products and services, we will need to be well on the path to developing and deploying tailored products and services for the full range of consumer needs:

Home EV charging and second-life batteries begin to link vehicle use with household energy management, setting the stage for integrated "energy plus transport" services.

Medium to highly engaged CER customers are projected to equal or exceed passive customers. Apps and smart dashboards can help households track and balance total energy spending, with automation tools optimising usage and charging times.

Early versions of "total-bill" management through electrification can give customers combined visibility of household electricity, heating, and transport costs.

We will need to find ways to increase participation in flexible demand or VPP programs for solar and battery households, often through automated orchestration. Meanwhile we will need to ensure passive consumers retain confidence by developing stable, low complexity offers such as subscription or multi-year fixed plans.

Although many consumers will be starting to experience more tailored products and service bundles, access is likely to remain uneven, as the capital cost of CER and fragmented interoperability still limits full inclusion for renters, apartment dwellers, and small businesses.

Current state

Most households still receive separate bills for electricity, gas and transport fuel, with limited visibility of their total energy cost or carbon impact. Price signals are poorly linked to behaviour, and energy literacy varies widely.

Retail offers remain consumption-based (¢/kWh) rather than service-based. Tariffs are largely static or time-of-use, and automation is minimal.

Around one-third of homes have rooftop solar, but far fewer have batteries or participate in demand response or VPP programs. However this has the potential to change rapidly with the right policy and market settings. Most consumers remain passive with limited incentive to provide flexibility.

Rising wholesale and network costs drive affordability pressures; and many consumers face "bill shock" rather than adaptive cost management.

Consumer Data Right and interoperability frameworks are emerging but not yet widely used/implemented.

Key risks and uncertainties

Affordability and inclusion remain significant risks as the upfront costs of electrification and CER participation will prevent many households and small businesses from taking part, leaving vulnerable consumers with the greatest exposure to price volatility and limited access to early support or capital investment.

The market and business model landscape is highly uncertain, with retailers facing shrinking margins, reform fatigue, and a lack of clear, standardised value streams for flexibility, comfort, or resilience services.

Technology, data, and interoperability challenges create further uncertainty, as fragmented devices and platforms, cybersecurity and privacy vulnerabilities, and the risk of AI bias or rapid hardware and software obsolescence undermine consumer confidence and system efficiency.

Regulatory and governance misalignment presents a major risk because policy is not keeping pace with digital and AI-enabled markets, while inconsistent state and territory rules for CER, EVs, and data rights along with blurred institutional roles create confusion and inefficiency.

Social licence may erode if consumers perceive transition costs are unfairly distributed, if communities oppose data use or large-scale infrastructure, or if workers fear job loss or automation.

Regulatory ambiguity adds risk, particularly where it is unclear whether network tariff signals are directed at retailers or intended to flow through them to end users.

There is an overarching uncertainty about whether the current retail model, which is highly dependent on energy volumes and risk management – can remain viable as electrification and CER reshape both revenue and risk profiles.

Public expectations around energy bills create another risk, as many consumers hold a fixed view of what their bill "should" be and may react negatively to new pricing structures or the introduction of bundled "energy-plus-services" products.

Some consumers will remain unable to reduce their usage due to household composition, building quality, health conditions, or appliance stock, which increases their vulnerability under dynamic or flexible models.

As the energy transition matures toward 2050, the system will reach a critical inflection point where incremental reform is no longer sufficient. Electrification of transport, heating, industry along with deep penetration of CER, and increasing climate volatility will place unprecedented strain on legacy retail, network, and wholesale market structures. At this point, policymakers will face a stark choice.

On one path, governments may allow parts of the market to fail under the weight of misaligned incentives, outdated regulatory frameworks, and rising social expectations. Traditional consumption-based retail models (designed for predictable demand and passive customers) will struggle to recover costs, manage volatility, and protect vulnerable consumers. The likely consequences include retailer exits, increased consolidation, reduced innovation, and a growing reliance on blunt regulatory interventions or taxpayer-funded backstops to prevent widespread consumer harm. While this approach preserves formal market neutrality, it risks eroding trust, weakening competition, and entrenching inequities between consumers who can engage with CER and those who cannot.

On the other path, policymakers actively work with retailers to redesign the market around service-based models that reflect the realities of a highly electrified, decentralised system. In this future, energy is no longer sold primarily as kilowatt-hours, but as outcomes – reliability, comfort, mobility, and bill certainty. Retailers evolve into system orchestrators, managing CER, demand flexibility, and wholesale exposure on behalf of customers, while shielding households and small businesses from complexity and risk.

Crucially, this redesign cannot rely on market forces alone. Service-based models require explicit policy and regulatory choices: clear consumer protections, minimum service standards, transparent value-sharing arrangements, and safeguards against exclusion or exploitation. Without these, outcome-based offerings risk becoming opaque, inequitable, or accessible only to the most engaged and affluent consumers.

The rise of EVs may create public concern because consumers may only observe their household electricity bills increasing, without immediately seeing the offsetting savings in fuel or maintenance.

Government policy interventions pose an additional risk if they create instability, add compliance burden, or override market-based signals that support innovation.

Retailer innovation capacity is constrained by limited bandwidth, especially as organisations juggle compliance, customer support, and investment in new technologies.

Critical enablers (to bridge the gap between current and future states)

Policymakers should support retailers in developing innovative retail models. For example:

- The expansion of fixed-price or subscription-style offers will help customers manage volatility and build confidence in electrified, flexible energy services.
- Stability in wholesale markets assists with predictable year-to-year wholesale pricing underpins consumer confidence and enables retailers to design fair, sustainable retail offerings. It remains to be seen whether multi-year contracts can compensate for year-on-year wholesale price volatility.
- Energy-as-a-service can be an enabler of the deployment of EVs, heat pumps, induction appliances, and other electrified technologies. National tariff harmonisation, carbon-linked pricing structures, and coordinated electrification incentives must be developed to create consistent and inclusive pathways for such technologies.

The energy system and its regulatory frameworks need to be designed with diversity as the default, acknowledging the intersecting realities of income, culture, gender, disability, digital access, and housing tenure as well as the potential disparities that arise as CER penetration spreads unevenly throughout the customer base:

- Energy bill assistance must be targeted to those who need it most through automated, centralised systems that reduce friction and ensure consistent support.
- Retailers and government agencies need automated methods to identify customers who require extra help and deliver assistance promptly and appropriately.
- Concession and hardship programs must become harmonised and portable so that customers retain support as they move between retailers, properties, and life circumstances.
- Value-sharing mechanisms must be explored to avoid the concentration of CER benefits among already advantaged households and to ensure that system value is distributed equitably. However, we should be cautious of applying blunt instruments such as universal high fixed network charges.
- Regulation should be aligned to supporting customer service outcomes such as fairness, quality and consumer welfare rather than controlling the unit price of electricity.

Transaction costs for switching, comparison, and consent need to be extremely low and supported by harmonised national frameworks that make customer participation simple and effortless.

Adaptive regulatory cycles must be established, with periodic reviews of tariff fairness, CER distribution outcomes, and inclusion metrics to ensure that the system remains equitable as it evolves.

Retailers need to remain the primary customer interface; responsible for billing, communication, and support, while simultaneously orchestrating CER behind the scenes to optimise household and system outcomes.

Consumers will require access to physical enablers such as CER installations, insulation, and double glazing to fully benefit from electrification and flexible services.

Trust will be a critical enabler, supporting uptake of innovation, willingness to share data, and broader acceptance of fair but unfamiliar pricing or service models.

A mid-2035 review will be essential to determine whether the retail market continues to deliver fair outcomes as technology uptake and consumer capability evolve. If meaningful divergence emerges, policymakers may need to consider a layered market structure, such as an inner and outer market or a universal service obligation, to preserve fairness and accessibility.[11]

Priority Actions to Deliver

Create regulatory and market frameworks that:

• Foster the development of more innovative retail models, (e.g. subscriptions, fixed-price offers and energy-as-a-service); and

• Ensure sufficient flexibility to allow retailers to cater to a much more diverse customer base with different needs.

[11] Dr Ron Ben-David has proposed the concept of an “inner and outer consumer energy market” to recognise that consumers differ in their ability and willingness to engage with complex energy services: the inner market would offer a protected, simplified retail environment, while the outer market would enable more active consumers to participate in dynamic pricing and distributed energy markets. Monash University submission to AEMC Pricing Review https://www.aemc.gov.au/market-reviews-advice/pricing-review-electricity-pricing-consumer-driven-future

Distribution Networks

Target Future State (at 2050)

By 2050, distribution networks will be the primary hubs for a highly distributed, flexible energy system, operating as active intelligent system platforms which facilitate and optimise the two-way flow of energy and data.

The network will host a high penetration of CER, including rooftop PV, batteries, EVs, and third-party energy schemes. Widespread and seamless integration of these assets will be the norm, with competitive retailers and aggregators playing an active role as market participants and investors in grid-side CER. This shift requires that networks facilitate open access to value pools and transparent information flow to retailers.

Networks will operate as active system platforms, coordinating with retailers and other aggregators to optimise flexibility and reliability via dynamic signals. This is supported by the adoption of advanced technology solutions, including AI integration.

CER assets will be fully integrated into market mechanisms, providing essential system support services (such as stability and contingency support) as well as participating in wholesale and ancillary markets. Regulatory frameworks will be harmonised across jurisdictions, enabling streamlined connection, data sharing, and consistent market access, which is key to avoiding fragmentation and risk.

The ultimate goal is a consumer-centric system where consumers and communities are active participants, benefitting both financially and operationally from more local energy solutions. This involves a shift of capital investment towards the household and community level, while networks focus on optimising investment in the "poles and wires" of the physical network as well as the software and sensors to enable continuous network monitoring, facilitating a shift to markets for services.

Stepping back from the customer experience of distribution networks, system operations and planning (to the extent centralised planning is still required) will be optimised between transmission and distribution).

Where do we need to be by 2035 to achieve the 2050 targets?

The path to 2050 requires significant progress by 2035. Networks will need to have largely achieved the following:

- Integration of high CER penetration: High CER and distributed energy resources (DER) penetration, including network-located batteries and public EV chargers, will be common across urban and regional areas.
- Active management transition: Networks will need to be well along the journey from purely passive electricity delivery to the active management of future grid-side CER, including community power networks, batteries, and EV charging infrastructure. The model (whether networks act as owners of these assets or merely coordinate third-party owners via signals) will be defined by regulatory settings.
- Coordinated flexibility: Networks will need to coordinate with retailers and aggregators to deliver flexible services, balancing local reliability needs with participation in wholesale market functions through established revenue-sharing models. Aggregated CER will be scheduled reliably into the spot market.
- The aggregation swing factor: The biggest variable for 2035 is whether the necessary regulatory, technological, and market enablers will have fully progressed to make aggregation and orchestration the

norm, not the exception. There is a need for co-optimisation between both centralised and distributed resources.

Current State

Today, most networks still operate primarily as passive delivery systems, with CER orchestration capability remaining limited, demonstrated only through initial trials of community batteries and EV chargers.

This limited active management capability, coupled with increasing CER penetration, creates genuine and immediate operational challenges. These include constraints around hosting capacity, voltage management, and congestion, particularly in the low voltage network. Export constraints currently drive a choice between traditional network augmentation investment and managed DER solutions.

A critical challenge is ensuring that investment decisions, by networks and third parties, correctly balance traditional network augmentation with CER-enabled solutions to defer costs and improve flexibility. Pilot programs across Victoria, South Australia, and New South Wales have demonstrated the feasibility of network-owned CER for peak management and reliability, but large-scale deployment remains hampered by Distribution Network Service Providers' (DNSPs) regulatory constraints and the risks of asset stranding for private investors.

A potential missed opportunity is to better utilise the sub-transmission part of the distribution network for hosting renewables and batteries, especially in the light of the escalating costs and delays of transmission expansion. While the ISP and jurisdictional programs are driving investment in REZs and strengthening key corridors, so that new generation and storage only pay for shallow connection charges, there is no equivalent mechanism for distribution or a cross-check whether distribution augmentation could unlock hosting capacity more cheaply (and potentially faster).

Key risks and uncertainties

The transition comes with risks that could delay or derail the 2050 vision:

- Crowding out private investment: Heavy network investment in CER, signalling a "network-first" approach, risks prioritising network assets over private initiatives. The deployment of network-owned community batteries, EV chargers, and hosting infrastructure which fulfills a market or service need that a third party might have targeted remains a contentious issue. There is a risk of overbuild and the need for further clarity on DNSPs' regulated vs. non-regulated activities.
- Lack of market signals: There is currently a lack of clarity over how to provide appropriate, efficient, and transparent signals to retailers, aggregators, and consumers to incentivise network support and efficiently defer investment where possible.
- Regulatory inconsistency and boundary issues: Regulatory and market arrangements for network participation in markets remain unclear and inconsistent across states. The AER's ability to manage boundary issues is tested by network ring-fencing waiver and sandboxing applications. The traditional regulatory framework is increasingly viewed as lacking the flexibility required for the transition due to rigidities arising from a capital expenditure (CAPEX) bias, risk aversion, the five-yearly reset cycle, and a lack of recognition of shared investment models. Political intervention and a lack of clear direction also constitute areas of risk.

Critical enablers (to bridge the gap between current and future states)

Achieving the 2050 future state requires implementation of the following critical enablers:

Regulatory evolution: Network regulation must evolve to become nimbler, creating more scope for mid-period opportunities, shared projects, and a focus on co-optimisation between centralised and distributed systems. This includes simplifying reporting and compliance obligations for operators deploying CER solutions. It also includes creating a level playing field and comparability between distribution and transmission hosting.

Market integration: Incentivise the market for CER-enabled reliability and market services through transparent, cost-reflective market mechanisms. This requires opening up the value pools for stability services and behind-the-meter/utility competition, ensuring customers are rewarded for participation and trust in managing assets is restored. Networks' ability to support such markets may require them to be allowed to increase investment into network visibility and platform development (still subject to appropriate efficiency testing of course).

Clarity on regulatory boundaries: Clear regulatory guidance on boundary issues is essential. This will allow networks to focus on their core business and the evolution towards being a two-way platform for consumer-owned and distributed resources, rather than competing with the market.

Standardisation and interoperability: This involves:

- Standardised technical requirements for community batteries, EV chargers, and hosting infrastructure.
- Shared guidelines for data access and interoperability between networks, retailers, and aggregators. There is a need for open access to value pools and transparent information flow across the value chain.

Streamlined connection and management: Streamlined and standard connection and approvals processes for CER are necessary to reduce friction. This should be supported by standardised digital platforms for CER management (on the DNSP side) to reduce transaction costs across the system.

Large users

Target Future State (at around 2050)

By 2050, large commercial and industrial (C&I) energy users should benefit from a reliable, competitively priced energy supply. This may include some of their own CER as well as grid supply.

C&I customers are easily able to sell or manage flexible load.

Energy intensive industries have successfully decarbonised.

Where patterns of industry have changed, communities have adapted either to the loss of old industry or the presence of new industry.

Energy supply will be responsive to new sources of demand and deliver additional capacity without putting upward pressure on prices for all consumers.

Where do we need to be by 2035 to achieve the 2050 targets?

We will need to keep up with demand, especially if there are new large loads connecting to the system. This will entail an acceleration of the deployment rate of firmed renewables and flexible supply.

Australia will be need to be clear on which industries it can have a competitive advantage in a net zero world so that support can be directed to where it is most impactful.

Large users benefiting from government support for their energy costs will need to be transitioning towards cost-reflectivity.

Current state

There is currently a two-way narrative regarding large users on the electricity system in the NEM. On the one hand, there are concerns that existing large users such as aluminium smelters are at risk of closing as current power costs make them uncompetitive. On the other hand, there are concerns that a wave of new large users – primarily data centres – could push up the cost of electricity for all users. Additionally, there are organisations such as the Superpower Institute who argue Australia is on the verge of a green metals boom due to our superior renewable energy resources[12]. It is difficult to reconcile all these competing narratives.

The affordability issues have led to a series of large but ad hoc Government bailouts. This has picked winners by saving some industries but allowing others to exit.

There are examples where the existing system is having a disproportionate impact on the competitiveness of some users. For example, half of Tasmania's transmission costs are currently recovered from just four large users.

Key risks and uncertainties

Data centre demand is unclear as connection enquiries don't always result in new load. AEMO and other planning authorities are developing approaches to better forecast realistic demand impacts but there will always be some residual uncertainty.

Diagnosis of what is driving the closure of large energy intensive businesses is always somewhat ambiguous due to factors such as:

- Ongoing support for large energy intensive businesses that doesn't involve a pathway to decarbonisation risks locking in emissions.
- Tensions between increasing load to use excess energy, with demand charges in network tariffs.
- The pace of policy and market reform, in particular the consistency and speed of net-zero policy impacts large users.

Critical enablers (to bridge the gap between current and future states)

Enable growth industries through integrated resource planning for new facilities – a question remains as to whether growth industries can access the power, other fuels, water, and skilled labour they need, without negatively impacting other resource users. This also includes understanding the opportunities to locate close to adequate power infrastructure.

Focus assistance for energy intensive businesses on helping them transition. This entails greater clarity over the scope and level of industry policy – developing a framework for assessing when support for large users is appropriate, and determining the conditions for support.

The development of sustainably-priced contracts (for both parties) which allows for internationally competitive pricing. Consideration is needed as to whether embedding policy costs in large user costs makes sense in the context of potential closures and subsidies to avoid closures. Widespread subsidies over the longer term are not going to be fiscally sustainable. This enabler is dependent on delivering the wholesale market reforms discussed above.

[12] https://www.superpowerinstitute.com.au/work/the-new-energy-trade

Policies that provide a level playing field between Australian and international businesses in terms of their emissions profile and how that is reflected in energy costs.

Priority Actions to Deliver

- Enable growth industries through integrated resource planning.
- Focus assistance for energy intensive businesses on helping them transition.

Regional Development

Target Future State (at around 2050)

By 2050, it is expected all major coal-fired power stations, as well as associated mines, will have retired to meet Australia's Net Zero goals. The desired future state is for the regions which hosted this coal infrastructure to have thriving local economies.

With regard to issues around social licence in the regions, the AEC envisages energy projects will be viewed as opportunities for regional development, rather than impositions.

Where do we need to be by 2035 to achieve the 2050 targets?

In the intervening years, the goal should be for the following objectives to be in place for each regional transition[13]:

- Objective 1: Both regional empowerment and national alignment on Just Transition are achieved through layered, inclusive and collaborative governance, vision-setting and resourcing models.
- Objective 2**:** The negative impacts of power station closure are mitigated and positive opportunities and benefits for regions, worker and industry are catalysed by implementing multi-year planning and preparation (via methodologies consistent with Objective 1).

Current State

The progressive closure of coal-fired power stations is already occurring. Some generators have already retired, including:

- Hazelwood Power Station in 2017. Despite the short notice of closure, the creation of the Latrobe Valley Authority led to lower unemployment rates in the region compared with the period prior to the closure. Ongoing activities include final decommissioning and remediation based around the creation of a pit lake for its mine void.
- Liddell Power Station in 2023. Plans are for the site to be re-purposed as an industrial renewable energy hub.
- Additionally, the industry has been working to ensure transition programs are in place in collaboration with state governments. These include:
  - Energy Australia's "Power your future" Program has been put in place to transition support to their workers once Yallourn Power Station closes in mid-2028.
  - Origin Energy's Future Directions Program supports Eraring employees with individual support plans prioritizing flexibility of employee choice.
  - AGL has supported their employees following the closure of Liddell, providing new work opportunities or guiding them through retirement.
  - Synergy's Workforce Transition Program, supported by the Western Australian Government provides tailored support, services, and resources to support employees for the anticipated closure of Muja and Collie power stations.

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[13] These objectives and other elements of this section are drawn from the 2022 report for the AEC by Strategen – Just Transition: Navigating Australia's energy transformation

The Federal and state governments have already begun several initiatives to support regional development through a just transition. Including:

- The recent establishment of the Net Zero Economy Authority by the Federal Government, which has recently consulted on the Energy Industry Jobs plan.
- The planned National Energy Workforce Strategy (NEWS), conducted by DCCEEW.
- The Victorian Energy Jobs Plan, due to be released in 2026.

Despite increased awareness of the energy transition, many regional communities remain uncertain about how new developments will affect them. The rollout of renewable and transmission infrastructure has often faced resistance where local engagement has been limited, or benefits unclear. There is an opportunity to better articulate the opportunities for new industries in these regional communities, especially under a well-managed transition.

Key risks and uncertainties

For more than a century, Australia's major energy generation has been concentrated in coal-rich regional communities such as the Latrobe Valley, the Hunter Valley, Central Queensland and Collie. As coal-fired power stations, and in some cases their associated mines, retire, these areas face the loss of major employers, with significant flow-on effects for local economic wellbeing.

A poorly managed transition risks compounding existing disadvantage, leaving workforces stranded and producing uneven consumer outcomes. This underscores the need for a whole-of-society effort, tailored to the circumstances of each community, to support a broader 'Just Transition' for these regions. At the same time, achieving social licence from other regional communities remains a significant barrier for both current and future transmission and generation projects.

Uncertainty over the timing of coal closures inhibits the timely implementation of regional just transitions.

Critical enablers (to bridge the gap between current and future states)

Early place-based transition planning for affected regions. There is no "silver bullet" approach to conducting a just transition for regional development, rather, there is a need for a timely whole-of-society effort tailored to the particular circumstances of each community. Some high-level solutions listed here:

High Level leadership

- Government engagement and resourcing that focuses on promoting economic growth and diversification while providing regional communities and impacted workers the maximum autonomy to choose their own future.
- Such investment should be focused on catalysing long-term opportunities for the regions and avoid short-term 'band aid' solutions

Community Empowerment

- Structured financial support directed to impacted regions and workers that respect local differences, which includes:
  - Impacted workers being supported and provided access to job retaining services to ensure the impact of diversification policies

Proactive, Comprehensive planning

- Proactive and timely transition planning in the years preceding each closure, with comprehensive multi-stakeholder engagement to reduce negative impacts on the region

- Both near-term and long-term solutions are necessary and must work together.

Building social licence

Re-learning and maintaining social licence is essential to achieving regional support for new energy projects, as also discussed in the Transmission section above. Work here could focus on building off successful case studies, such as the Wimmera Southern Mallee (WSM) Collaboration, and encompass the following principles:

- Early, genuine engagement with host communities before project decisions are finalised.
- Clear, consistent communication on local benefits and project impacts. Tangible community benefits such as jobs, infrastructure and investment.
- Local participation in project planning and monitoring.
- Delivery on commitments to build long-term trust and credibility.

6. National Emissions Reductions and Targets

Target Future State (at around 2050)

The desired state is for both the economy as a whole and the electricity sector to reach net-zero emissions by 2050. There is an ongoing debate over how close the electricity sector will get to "real zero". While that debate will continue to evolve, AEMO's Integrated System Plan gives the current best indication of the technology fuel mix which will be needed in a net-zero energy system. That technology mix includes a need for around 15 GW of flexible gas for firming capacity.

The expectation of a role for gas in a future decarbonised energy system means a mix of renewable gases and/or some level of offsets will be allocated to the electricity sector.

The desired state in 2050 should then consist of:

- Net-zero emissions across the electricity grid.
- Understanding of and bipartisan support for the optimal energy technology mix.
- Economy-wide carbon signal that allows for the efficient allocation of offsets across each sector.
- Bipartisan support for market-based settings, with minimal government intervention, to drive future energy investment.

Where do we need to be by 2035 to achieve the 2050 targets?

The Federal Government recently announced its commitment to achieving an economy-wide 62% to 70% emissions reduction target by 2035. What this means in terms of the policy direction for the electricity sector is yet to be decided federally, however some states have checkpoints for 2035 (for example, Victoria has a renewable energy target of 95% by 2035). There will also likely be interim targets for 2040 and 2045 by this point.

It is expected that the electricity sector will have reached high renewable penetration by 2035, and there will be policy support for essential firming and system security technologies to maintain a reliable grid. The Capacity Investment Scheme will have wound down and market-based settings (such as the proposed ESEM) will be in place from 2030 or earlier to drive further investment.

Nonetheless, the whole-of-economy 2035 target will be challenging to meet. There will need to be a range of abatement policy settings in place across all major sectors of the economy by 2035 in order to reach these targets and net zero by 2050. This may in turn drive more electrification or stimulate a renewable hydrogen sector, leading to additional electricity demand.

Current State

Australia is currently working towards a 43% emissions reduction target by 2030. While this target is economy-wide, it is underpinned by achieving the 82% renewable electricity target by 2030, which means the electricity sector is receiving most of the political and policy action. The Federal Government's signature policy is the 'Capacity Investment Scheme'.

Complicating an assessment of the 'current state' is that electricity is technically a state responsibility, and all states have their own targets and trajectories. A summary of these targets is in the AEMCs Targets Statements, but they do not necessarily align, which make analysis difficult. There are also some highly specific technology targets that may not align with a least cost transition.

Assuming the Commonwealth's targets prevail, the electricity sector is currently working towards 82% renewable electricity in 2030. The Climate Change Authority's Annual Progress Report suggests there are significant challenges to reaching that target, mainly on the supply-side. These include community resistance, environmental assessment planning, as well as approval and timely AEMO grid connections.

Key Risks/Uncertainties

<u>Political and social</u>

Loss of bipartisan support for net-zero means the investment framework is constantly swinging and uncertain as governments change.

Community resistance to energy infrastructure projects slows the rollout and energises political opposition to net-zero.

There is ongoing, fractious debate about the optimal electricity technology mix which leads to uncertain investment frameworks that further delay the transition.

<u>Economic and commercial</u>

Political uncertainty reduces the investment case and means some technologies needed for the transition are not commercially viable.

Regardless of politics, some technologies do not commercially scale fast enough.

Apart from the Safeguard Mechanism, most abatement policies do not have a 'hard' target. It's unclear how policies will be adjusted to meet targets if they are delivering less abatement than expected.

<u>Technical</u>

Known or unknown issues emerge relating to the operation of a high VRE grid.

Critical enablers (to bridge the gap between current and future states)

- Realign jurisdictional emissions targets to deliver a nationally consistent trajectory.
- Implement policies to driver emissions reductions across all sectors. An economy-wide carbon signal is in place which identifies where abatement is most economically efficient, reducing the need for government policy. Government interventions are kept to a minimum and jurisdictional policies are aligned to the extent possible.
- Bipartisan support for net zero emissions by 2050, and 'closer bookends' about the optimal energy technology mix to get there. However, technology-specific targets should be avoided.
- Achieving community acceptance of the energy transition, putting frameworks in place to increase benefits to regional communities hosting new infrastructure and mitigating impacts for communities where emissions-intense infrastructure is closing.
- Clear governance around how policies will adjust if abatement occurs faster or slower than predicted across the economy.
- Well-designed electrification and energy efficiency policies, and a good understanding of the minimum and maximum energy demand levels in the future.

Priority Actions to Deliver

- Realign jurisdictional emissions targets to deliver a nationally consistent trajectory.
- Drive reductions across all sectors.
- Avoid technology targets.

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