Future of electricity network regulation

Information paper

June 2026

AUSTRALIAN ENERGY REGULATOR

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AER reference: AER32079464

Amendment record

Version	Date	Pages
1.0	17 June 2026	59

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Introduction

The electricity system is undergoing significant change. To ensure this change is delivered in the long-term interests of consumers, we must consider whether the regulatory framework for network services has the right structures and tools in place for the evolving electricity system.

Electricity network service providers, including transmission network service providers and distribution network service providers, are natural monopolies that provide essential services. We regulate these services to promote economic efficiency because it will maximise the welfare of Australians and achieve broader objectives for the long-term interests of consumers. Ensuring that electricity networks are efficient has a ripple effect across the economy and reduces costs for consumers over time. An efficient energy system is beneficial for all Australians.

We also regulate to protect consumers. For example, regulation of electricity networks protects consumers from unnecessary costs while ensuring the system delivers what they value, such as a safe and reliable supply of energy. Regulation can also make systems fairer and more equitable.

However, the changing electricity system raises new challenges and questions for our regulatory framework. Decentralisation and digitalisation are unlocking new ways to respond to problems that have traditionally required physical network investments, potentially creating new opportunities for contestable markets. At the same time, network service providers are increasingly expected to act as platforms that enable and coordinate energy services. The role of network service providers within the system – especially distribution network service providers – is changing.

This paper shares our observations on the evolution of our electricity system, the regulatory framework, and provides some context to consider the strength of the current framework in response to the future state of the electricity system. The issues are explored in this paper through the following sections:

- The rationale for why we regulate networks (Section 1)
- Phases of the electricity industry and regulation reforms (Section 2)
- Key characteristics of the current regulatory framework and tools that directly control and influence the performance, practices and conduct of how we regulate networks in the National Electricity Market. (Section 3)
- What and how we regulate in the National Electricity Market (Section 4)
- How the electricity network may evolve into the future, and future challenges the regulatory framework may face (Section 5).

The AER is committed to adapting the regulatory framework for electricity networks so that it continues to act in consumers' long-term interests as technologies, service models and economic conditions change. We are exploring this by asking whether what and how we regulate still aligns with why we regulate – and whether it will continue to align moving forward.

Our exploration of these questions will inform our approach to reviewing AER guidelines and engaging with broader reform initiatives, including the Australian Energy Market Commission's (AEMC) Electricity Network Regulation Review and relevant rule change processes. Figure 1 outlines the stages of our work.

This paper provides context to understand the regulation of networks in the National Electricity Market, and the way it is operationalised by the AER. With the AEMC soon to begin the most significant review of network regulation since 2020, and with a rapidly-evolving electricity system, the AER is proactively examining the current regulatory environment to support the development of national energy policy.

Figure 1. Stages of our foundational network analysis for network regulation review

- **Objective:** Develop preliminary thinking on why and what we regulate to inform direction for further work.
- **Objective:** Develop a useful framework for thinking about the future of network regulation to enable us to identify problems and options for change.
- **Objective:** Identify problems in the framework (e.g. gaps in what and how we regulate given changes we can foresee) and options for change to agree next steps and directions for future work.
- **For example:** Guideline reviews, rule change proposals or reform recommendations.

Much of the discussion in this paper is centred on issues that affect distribution network service providers, reflecting the pace of change driven by distributed energy and coordination challenges. Transmission network service providers face common issues to distribution, but we recognise there are distinct issues facing the transmission sector. The AER will engage with both in the AEMC reform processes and our broader work on network regulation reform.

1 Why we regulate

The problems that electricity network regulation has responded to can be grouped into recurring themes. Some relate to network investment, where networks may under- or over-invest in capacity in ways less likely under competition. Others relate to access, where connecting parties may face inefficient barriers to using the network. Regulation has also responded to information asymmetry, which can make efficient costs harder to assess. In operational terms, multiple participants may need coordination to maintain system stability. More broadly, individual incentives may not align with system-wide efficiency, and network monopolies may constrain innovation and competition in adjacent markets.

Many of these problems are consequences of the monopoly structure of electricity networks. Natural monopolies arise when there are prohibitively high fixed costs (for example, for distribution and transmission infrastructure), which mean that it is more efficient for one provider to deliver a service. However, this creates other efficiency problems because a single provider, facing limited competitive discipline, may not invest, operate or innovate to maximise efficiency. This can include artificially raising prices above efficient levels or providing services at a lower quality than desired or that consumers are willing to pay for.

Monopoly problems respond to corrective regulation that limits the monopolist's behaviour to approximate the efficiency outcomes a competitive market would deliver. This has been the primary focus of economic regulation in the energy sector since the formation of the National Electricity Market. The regulatory framework is designed to address these monopoly problems in pursuit of economic efficiency, consistent with the National Electricity Objective. But the transition to a renewable-based energy system is making coordination, rather than monopoly behaviour alone, a key driver of consumer outcomes.

Box 1. Key dimensions of economic efficiency for electricity networks

- **Productive efficiency** – Are we building and operating the network at least cost for a given level of service? For example, where networks encourage shifts in consumption from peak to off-peak it can increase the utilisation of electricity networks and reduce the need to upgrade, supporting the provision of an equivalent level of electricity services at lower cost.
- **Allocative efficiency** – Is the network providing services in ways that generate the most value, given the costs of providing those services? For example, scarce network capacity being allocated among competing users and uses in ways that don't reflect the value those uses generate, represents an allocative efficiency failure.
- **Dynamic efficiency** – Is the regulatory framework creating incentives for investments and innovations that meet the changing needs of the energy system over time?

Coordination requirements are growing within networks, at their interface with competitive markets and across the energy system as a whole.

The current electricity system is transitioning and can be characterised by widespread distributed generation and storage, more flexible demand, two-way power flows on distribution networks, and more diverse resources on both transmission and distribution networks. Distributed solar and battery systems have become prevalent. A large portion of these are end-consumer based distributed assets that enable consumers to substitute electricity supply from the grid with their own generation, while others are larger systems operated by commercial entities as participants in various NEM-based markets. An efficient energy network in this context must enable multiple parties to make increasingly interdependent decisions through and about shared infrastructure.

Because all participants in the electricity system must transact through shared network infrastructure (whether consuming, generating, storing or trading energy), networks and related services necessarily perform coordination functions – for example, managing access to shared infrastructure, allocating network capacity between competing uses, and providing data and platforms that enable connected parties to optimise interdependent decisions.

These functions do not reside solely with NSPs – those who manage the interface between the network and consumers, such as retailers, also perform coordination functions that affect the efficiency of the network (for example, by impacting the efficiency of network utilisation). Increasingly, new energy service markets, beyond the simple purchase of energy, involve the coordinated use of flexible load, fast response, demand response at scale, home batteries and smart appliances. These services are emerging in the mass market and rely on many small consumer-side resources responding in ways that support both consumers and the efficient operation of the network. Parties that perform coordination functions provide the framework within which energy service markets can operate. Inefficient performance of coordination functions risks significant harm to consumers (for example, higher than otherwise energy prices).

Our regulatory framework is focused on addressing monopoly problems – it has not been designed to address these risks to the same extent. For example:

- where coordination functions are performed by regulated networks (for example, through the emerging distribution system operator role, operating envelopes or flexibility procurement), the existing framework governs the network's expenditure on coordination but not the quality, neutrality or effectiveness of the coordination itself
- where coordination functions are performed by competitive market participants (such as retailers, metering coordinators, aggregators and flexibility providers), the framework has limited tools to ensure that the functions are performed in ways that support efficient system outcomes beyond the commercial interest of whoever controls them
- where the coordination function sits at the interface between the regulated network and the competitive market, the framework governs each side according to different principles but does not govern the interface itself.

Box 2. How coordination functions have migrated beyond the framework

Two illustrations show how coordination functions can sit beyond the regulatory perimeter even when the underlying service is formally contestable

- **Contestable metering –** the Power of Choice reforms made metering contestable on the basis that competition would drive innovation and accelerate smart meter deployment. The physical asset became contestable, but the coordination functions that depend on the asset (data management, communications, network integration and the interface with market systems) remained closely coupled with the network and the centralised market processes. The metering market has since consolidated significantly, with a small number of metering coordinators now managing the vast majority of installations in the NEM. The forthcoming sale of one of the largest metering coordinators to private investors has illustrated the value of its established position managing metering data and communications. The coordination function moved beyond the boundary of the regulatory framework before being subsequently consolidated in a way that may not align with the scale and potential impact of the function.
- **Competitive retail** – Retail contestability was introduced on the basis that competition between retailers would deliver efficient price signals, improve service and consumer choice. In practice, the retail market remains dominated by a small number of vertically integrated gentailers holding the majority of residential customers in most NEM jurisdictions. These retailers occupy a critical position in the coordination chain between the network, the wholesale market and the customer,

performing an optimisation function across multiple value streams (wholesale energy costs, network charges, demand flexibility, ancillary services and behind-the-meter resource dispatch) and determining how the resulting value is allocated. A vertically integrated gentailer may face commercial incentives that diverge from efficient system coordination, with limited regulatory visibility of the coordination function itself.

Both examples suggest that the effectiveness of network regulation is bounded by the extent to which coordination and value-allocation functions performed beyond the network perimeter support efficient system outcomes.

These observations suggest it is timely to reconsider the structures, tools and incentives of our regulatory framework for electricity network services. The regulatory treatment of distribution services currently falls into 3 categories – direct control services (standard control and alternative control), negotiated distribution services and unregulated distribution services. Unlike in transmission, the AER plays an active role in classification at the framework and approach stage of each distribution determination. We first consider whether an activity is a distribution service and, if it is, what form of regulation is efficient having regard to the form of regulation factors. In effect, services classification is where we decide what 'sits inside the perimeter' of distribution NSP-provided services and what should sit outside. Our services classification decisions determine the nature of regulation of a service, if any.

More broadly, for example, service classification and ring-fencing have usually been treated as a trade-off between allowing distribution NSP delivery and protecting contestable markets, but this framing may be incomplete because some services rely on coordination across both regulated networks and competitive providers, meaning that neither a strictly inside nor outside perimeter approach may always be sufficient.

These features of the framework are examples of the same interface that emerging coordination functions are increasingly crossing. As new and emerging distribution network services develop, questions arise about which of those services perform coordination functions, which participants will need to access those functions and how the mechanisms that define the boundary should respond. Questions also arise about how well our framework as a whole will perform in driving efficient outcomes in the long-term interests of consumers and the transformation of the energy system continues. These are questions we will explore in forthcoming work.

2 Evolution of the electricity industry and regulation

Change is nothing new for the electricity industry. The current regulatory framework has evolved in response to changes in the broader conditions of the energy system over time (such as to technology, market structure or government policy). In responding to these changes, the regulatory framework has aimed to address specific problems. These changes, problems and responses are summarised below within 5 phases which capture a brief history of our energy system and regulatory framework as it relates to the issues we face today.

2.1 A centralised system (pre-1990s)

Electricity provided by state-owned, vertically integrated monopolies. The electricity systems were centrally planned, with investment and operations directed by State Electricity Commissions and with limited interconnections between states. Electricity was reliable, widely available and considered a source of economic growth and regional development. However, monopoly structures and central planning decisions created inefficiencies, laying the foundations for major reform in the 1990s.

For much of the 20th century, Australia's electricity system was comprised of state-owned, vertically integrated monopolies. State Electricity Commissions managed generation, transmission, distribution and retail supply and were accountable to State governments for planning, investment, operations, reliability and tariff setting.[1]

Throughout the 1980s, the vertically integrated utilities model gave rise to significant monopoly-related challenges, particularly in relation to capital allocation and economic efficiency. Investment decisions were largely insulated from market-based incentives and performance accountability, leading to excess generation and transmission capacity.[2]

Rapid growth coincided with very low electricity prices, supporting energy-intensive industries and rising living standards.[3] In 1990, the sector comprised 34 state-owned corporations, with the broad objective of meeting household and business demand for reliability.[4] Interstate trade of electricity was limited.

Prices did not reflect efficient costs, blunting signals for efficient consumption and investment, while the absence of competitive or regulatory pressures limited incentives for productivity improvements.

By the 1990s, these challenges intersected with broader shifts in Australia's economic policy and objectives. Efforts to achieve economic growth, low inflation, and greater international competitiveness

1 T Nelson, S Bashir, E McCracken-Hewson & M Pierce, *The Changing Nature of the Australian Electricity Industry*, February 2017.

2 P Simshauser, *From First Place to Last: The National Electricity Market's Policy-Induced 'Energy Market Death Spiral'*, December 2014.

3 A Rai and T Nelson, *Australia's National Electricity Market After 20 Years*, Australian Economic Review, vol. 53, no. 2, 2020, pp. 165–182.

4 D Richardson, *The Costs of Market Experiments: Electricity Consumers Pay the Price for Competition, Privatisation, Corporatisation and Marketization*, The Australia Institute, January 2019.

prompted scrutiny of government-owned utilities sectors and their reliance on subsidised, centrally planned service provision.[5]

Regulatory intervention throughout this period largely occurred through minimal state-based regulation, rather than broad-based Federal reforms. From the late 1980s, Australian governments began introducing microeconomic reforms across telecommunications, electricity, water, road, and rail; however, these reforms were pursued on a sector-by-sector basis and lacked an overarching framework integrating economic principles with political governance.[6] This fragmented approach highlighted the need for a more coordinated reform agenda and set the stage for the more comprehensive restructuring of the electricity sector during the 1990s.[7]

2.2 A new market (1990–2005)

Major competition reforms dismantled state-owned electricity monopolies, drawing a clear boundary between the natural monopoly elements of the electricity system (transmission and distribution networks) and those segments where competition was expected to deliver efficient outcomes, including in generation and retail supply. These reforms led to the establishment of the National Electricity Market (NEM), which initially delivered stable prices and reliable supply under conditions of inherited excess capacity and relatively predictable demand. Consumers were viewed largely as passive end-users of electricity.

In the early 1990s, Australia's state-based electricity provision faced structural and regulatory inefficiencies: vertical integration meant generation, transmission, distribution and retail were managed as a single system, contributing to excess generation capacity, underutilised infrastructure and prices that often did not reflect the true cost of supply.[8]

These conditions led to concerns about inefficiency in the economy and reinforced the case for competition, better access to essential infrastructure and removal of barriers to entry to support more efficient investment, innovation and service delivery.[9]

An early inquiry that examined these issues was the Industry Commission's *Energy Generation and Distribution* inquiry (1991), which argued that the restructuring of the electricity sector could produce significant GDP gains through privatisation, deconstruction of vertical integration, competition, providing fair access to the transmission and distribution networks and the formation of a national grid with independent regulatory oversight.[10]

The 1993 *Hilmer Report* built on the findings of the Industry Commission and recommended reforms to allocate the risks of investment in generation and retailing to market participants, and away from consumers and taxpayers. This was intended as a means to achieving allocative efficiency and greater productivity. As such, the report recommended that monopoly sectors – such as electricity – be exposed to competition wherever feasible, with regulation applied only where monopoly

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5 KPMG, *National Electricity Market: A case study in successful microeconomic reform, report for the Australian Energy Market Commission,* AEMC, 2010.

6 KPMG, *National Electricity Market*, 2010.

7 M Parkinson, *Reflections on Australia's era of economic reform,* address to the European Australian Business Council, December 2014.

8 P Simshauser, *The regulation of electricity transmission in Australia's National Electricity Market: user charges, investment and access*, March 2023.

9 KPMG, *National Electricity Market: A case study in successful microeconomic reform, report for the Australian Energy Market Commission*, AEMC, 2010.

10 Industry Commission, *Energy Generation and Distribution Volume I*, 1991.

characteristics were unavoidable or competition conflicted with other social objectives.[11] This principle (that competition should be the default and regulation confined to where natural monopoly made competition impracticable) provided the foundational logic for determining what fell inside and outside the regulatory perimeter. Consequential reforms in the early-to-mid 1990s corporatised and privatised electricity commissions, unbundled the supply chain through vertical separation and increased competition in generation and retail, while retaining transmission and distribution as regulated monopolies.[8] The National Grid Management Council was also established to coordinate the development of a competitive electricity market.

These reforms paved the way for the NEM, aimed at providing a reliable, secure supply at the best possible price.[12] The NEM commenced on 13 December 1998, providing a competitive market for the supply and purchase of electricity in New South Wales, Victoria, Queensland, South Australia and the ACT. Tasmania later joined the NEM on 29 May 2005.

Inherited surplus capacity and new plant additions kept wholesale prices stable and real electricity prices low, and the NEM operated in a relatively 'steady state' with predictable demand growth and regulatory decisions broadly understood by investors and consumers.

In 2000, the NEM's energy mix was 92% coal and gas with hydro at 8%. Wind output rose from 58 GWh in 2000 to 885 GWh in 2004–05 as commercial deployment gathered pace.[13]

In 2001, the Australian Government introduced the Mandatory Renewable Energy Target (MRET) to lift renewable generation and reduce electricity sector emissions. The targets drove early investment in biomass, landfill gas and wind, and supported Australia's first commercial utility-scale wind project (Codrington Wind Farm in Victoria), alongside a broader global upswing in renewable investment in the mid-2000s.[14] Utility-scale renewables were an early catalyst for transmission network development, highlighting the need for new regulatory frameworks to fund and build the infrastructure needed to connect new generation projects to the market.

The Parer review in 2002 identified issues in governance arrangements in the electricity sector, including a multiplicity of regulators across the states, perceived conflicts of interest where state governments were both the owner of electricity companies and regulators of those companies, and barriers to entry for embedded generation.[15] These issues discouraged interstate trade, private investment in the industry, and were barriers to industry growth. The review also proposed the establishment of a national regulator to harmonise regulation, and nodal pricing to provide better investment signals to generation and transmission.

The National Electricity Code (authorised by the ACCC and administered by National Electricity Code Administrator) established an incentive-based framework for regulating monopoly networks. The ACCC's Statement of Regulatory Principles (2004)[17] operationalised this approach and supported investment certainty and revenue regulation with the ACCC (later the AER), with many distribution and retail activities still regulated by state and territory jurisdictions.

The AER and the AEMC were established in July 2005 as part of reforms to national electricity market governance arrangements. The initial functions of these bodies were responsibility for wholesale electricity and transmission network regulation. The AER was established under the Trade Practices

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11 F Hilmer, M Rayner and G Taperell, *National Competition Policy: Review Report (The Hilmer Report)*, August 1993.

12 F Hilmer, M Rayner and G Taperell, *National Competition Policy: Review Report (The Hilmer Report)*, August 1993.

13 DCCEEW, Australian electricity generation renewable sources, Australian Government, 2020.

14 Clean Energy Regulator, *Renewable Energy Targets*, January 2026.

15 W Parer, *Towards a truly national and efficient energy market, Council of Australian Governments*, Energy Market Review, December 2002.

Act 1974 as a constituent part of the ACCC. It provided a harmonised regulatory framework across NEM states, undertaking the regulatory and enforcement functions previously held by the ACCC and the National Electricity Code Administrator.

In 2005, the National Electricity Law replaced the Code objectives with the National Electricity Market Objective, framed around economic efficiency and long-term consumer welfare (and broadly aligned with the current National Electricity Objective, absent an emissions reduction factor), reinforcing a commitment to competitively neutral settings and continuity with the earlier market objectives.[16]

Box 3. Key economic principles on which the NEM was founded

- **Appropriate risk allocation:** Investment and operational risks rest largely with market participants, who have the best information, expertise and incentives to manage them.
- **Promoting competition:** Competitive markets in generation and retail drive efficiency and lower costs.
- **Flexibility and resilience:** Market and regulatory frameworks are designed to adapt to new technologies and evolving consumer expectations.
- **Reducing production costs:** Efficient pricing and competition incentivise lower-cost electricity production.[17]

2.3 An expanding system (2006–2015)

Incentive-based regulation was codified in the NER. Network investment expanded rapidly despite falling demand and utilisation, leading to overbuilt assets and rising consumer bills. Consumers were now viewed as 'shoppers' exposed to retail competition and increased household uptake of small-scale solar, energy efficiency and flexible loads was supported by demand-side participation reforms. At the same time, governments increasingly used renewables and emissions policy levers to reshape the energy supply mix through strengthened renewable targets, public finance and (briefly) carbon pricing. However, uneven coordination between energy regulation and climate policy created an uncertain investment environment and blurred pathways for emissions reduction.

Between 2006 and 2015, the NEM saw rapid transmission and distribution expansion, largely driven by tighter reliability standards after major outages in NSW and Queensland, made without clear alignment to consumers' willingness to pay.[18] Network utilisation fell materially as investment increased (for example, average distribution utilisation was 57% in 2006, falling to 39% in 2015).

Over this period, the generation mix remained coal-dominated (with gas firming peaks and hydro varying by water availability), while wind generation rose from 1.7 TWh (2005–06) to 11.5 TWh (2014–15) and solar generation rose from 0.09 TWh to 5.53 TWh, driven largely by rooftop PV.[19] Residential solar uptake was supported by rebates and feed-in tariffs (including Solar Credits and high feed-in tariffs introduced between 2009 and 2013 by different jurisdictions).

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16 South Australia, Parliamentary Debates, House of Assembly, 9 February 2005, 1452 (Hon JD Hill for Hon PF Conlon, Minister for Energy).
DCCEEW, *Australian Energy Market Agreement 2013*, December 2013

17 A Rai and T Nelson, *Australia's National Electricity Market After 20 Years*, August 2020.

18 A Rai and T Nelson, *Australia's National Electricity Market After 20 Years*, August 2020.

19 DCCEEW, *Australian electricity generation from renewable sources*, February 2026.

Rising prices, early CER uptake and the ability to choose retailers also began to position consumers as more active participants in the electricity system. CER in particular enabled some consumers to partially substitute grid-supplied electricity through rooftop solar generation. These were supported, in many cases, through regulated feed-in tariffs that incentivised the uptake of small-scale generation.[20]

Accelerating network investment resulted in a near-tripling of network asset bases and sharp increases in residential bills through higher network charges.[21] Rising coal and gas prices discouraged new dispatchable investment, contributing to abrupt generator exits and elevated wholesale prices.

Network regulation continued to evolve during this phase, embedding a comprehensive, incentive-based transmission economic regulation framework into the National Electricity Rules via the AEMC's Economic Regulation of Transmission Services rule (2006). This rule formalised National Electricity Code-era approaches to network regulation and clarified incentive-based, multi-year revenue-cap/CPI–X style arrangements and the associated investment and cost assessment frameworks.

A comparable national distribution framework commenced from 1 January 2008 as the AER began economic regulation of distribution networks under the amended national electricity rules (with transitional arrangements in some jurisdictions). This saw the regulatory framework mature around the model of privately owned or corporatised monopoly NSP regulated by an independent public authority.

The National Electricity Market Objective was amended to the National Electricity Objective in 2007, with policymakers emphasising an efficiency focus for the AEMC and AER in performing their functions and noting that the Objective should not extend into broader social and environmental objectives.[22]

The AER also began administering jurisdictional ring-fencing arrangements from 2008, initially focused on separating regulated network services from contestable retail and generation.[23]

As CER grew, the AEMC's Power of Choice Review (2012) drove reforms that once smart meters were universally available could achieve cost-reflective network tariffs, improved integration of CER into planning and operations, and enabling flexible load participation to improve efficiency and reliability, reflecting the view that consumers could be increasingly active participants.[24] The underlying premise of these reforms was that consumers would have more options and information to decide how they choose to produce and use electricity in an evolving system.

2.4 A decentralising system (2016–2022)

The NEM shifted from a centrally supplied, fossil-fuelled model toward one with more variable renewable energy and more decentralised, consumer resources. Coal closures and a tightening supply–demand balance increased the role of wind and solar and heightened the need for new

[20] Y Zhang and X Zheng, *Regional disparity of residential solar panel diffusion in Australia: The roles of socio-economic factors*, Renewable Energy, vol. 206, April 2023;
R Ben-David, *Rethinking markets, regulation and governance for the energy transition*, prepared for the ACCC/AER Regulatory Conference, Brisbane, Australia, August 2023;
A Abban & M Hasan, *Solar energy penetration and volatility transmission to electricity markets — an Australian perspective*, Economic Analysis and Policy, vol. 69, 2021, March 2020, pp. 434–449.
Deng et al, *Deploying solar photovoltaic through subsidies: An Australian case*, Journal of Environmental Management, December 2024.

[21] A Rai and T Nelson, *Australia's National Electricity Market After 20 Years*, 2020, pp. 165–182.

[22] South Australia, *Parliamentary Debates, House of Assembly*, 27 September 2007, 964 (Hon PF Conlon, Minister for Energy).

[23] Australian Energy Regulator, *AER Ring-Fencing Guideline – Preliminary Positions Paper*, April 2016.

[24] Australian Energy Market Commission (AEMC). *Power of choice review – giving consumers options in the way they use electricity: Final report*., March 2012.

transmission to connect generation distant from load centres, alongside stronger system coordination – most notably AEMO's first Integrated System Plan (ISP) in 2018. At the same time, rapid uptake of consumer energy resources (including solar PV, batteries and more flexible loads such as emerging electric vehicle demand) reshaped distribution networks, accelerating reforms to manage two-way flows, integrate distributed energy resources (DER) into planning and operations, and refine ring-fencing in a more complex market. These coordination challenges differed from the monopoly pricing and investment efficiency problems that the Phase 2 and 3 regulatory tools were primarily designed to address. This transition would not have been possible without the roll-out of the smart meter reform. Without digital meters or automated control systems there could be no meaningful demand side participation. While Victoria completed the roll-out of smart meters in 2013, the NEM is not expected to have universal smart meters until 2030.

From 2016 to 2022, Australia's electricity system shifted toward a more decentralised, low-emissions mix as coal exited and variable renewables and CER grew. This increased the need for new transmission to connect generation located further from load centres and for more coordinated system planning, with congestion and weak system strength causing issues in the NEM and higher integration costs.[25].

The introduction of the ISP reshaped transmission network planning – but not distribution level or demand side planning - and drove a large pipeline of capital-intensive transmission augmentation.[26] Renewable investment accelerated in the late 2010s (supported by higher wholesale prices after 2015), but higher shares of variable renewable generation exposed limits in connection and system-strength arrangements—especially in weaker parts of the grid—reinforcing the case for coordinated transmission and essential system services.[27]

Consumers began making increasingly sophisticated choices about their electricity load, supply and storage.[28] The growth in CER, along with export pricing incentives offered to retailers by the networks, also highlighted the potential for households and businesses to provide network services, including easing congestion to avoid augmentation or replacement network infrastructure. Decarbonisation and two-way system requirements also began to stretch traditional network roles, heightening concerns about efficient coordination versus risks of cross-subsidisation and market power and increasing the importance of ring-fencing and clear access and service arrangements.

The AER's 2016 distribution ring-fencing guideline expanded earlier arrangements to address contestable metering and emerging technologies (including solar PV and storage) and protect competition.

Rapid growth of variable renewables and CER increased the operational and regulatory complexity of the NEM. While the rapid adoption of solar capacity significantly increased total generation, with rooftop solar accounting for around 25.8% of total renewable energy generation in 2025[29], it has also created challenges for the system. A system built for predictable synchronous generation and one-way flows struggled with weather-dependent supply and distributed resources, revealing gaps in system strength and inertia, frequency and voltage control, DER visibility, and coordination across transmission, distribution and wholesale operations.[30]

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25 AER, *AER electricity wholesale performance monitoring – Hazelwood advice*, 2018.

26 DCCEEW, *Review of the Integrated System Plan – Final Report*, January 2024

27 Clean Energy Council, *Clean Energy Australia Report 2019*, Clean Energy Council, April 2019.

28 R Ben-David, *Rethinking markets, regulation and governance for the energy transition*, prepared for the ACCC/AER Regulatory Conference, Brisbane, Australia, August 2023

29 Renewable Energy Council, *Australian Rooftop Solar Breaks New Ground In 2022: Clean Energy Australia Report*, April 2023.

30 AEMO, *2024 Integrated System Plan*, June 2024.

These issues were highlighted by the Finkel Review (2017), which found that the NEM's design and governance arrangements had not kept pace with the technical needs of a more variable and decentralised system, and that policy uncertainty weakened investment signals. The review called for frameworks that better value reliability and system security services, clarify DER integration and provide a more coherent emissions pathway.[31]

Findings from the Finkel Review led to reforms on system security, reliability, prices, emissions, including the Generator Reliability Obligation, Mandatory Generator Closure Notice, explicit FCAS and inertia requirements, five-minute settlement and the ISP as a whole-of-system transition roadmap.[32] The Energy Security Board was established in 2017 following the Finkel Review to provide whole of system oversight for energy security and reliability of the NEM, and to improve long-term planning.

Other reforms relating to CER and demand-side participation included the AEMC's Access, Pricing and Incentive Arrangements for DER rule (2021),[33] the AEMC's wholesale demand response mechanism (2001)[34], AER's network tariff reform program and DER integration guidance (including its Customer Export Curtailment Value methodology), and the AER's regulatory sandbox to trial new technologies and business models. The Post 2025 electricity market design proposed a package of reforms to National Cabinet, including on resource adequacy and retirement of ageing generation, essential system services, effective DER integration, and transmission and access.

From 2019, States developed Renewable Energy Zones to proactively coordinate generation, storage and network augmentation where national processes were viewed as too slow or insufficiently used, highlighting growing coordination needs beyond the existing national framework.[35] In 2020 the AEMC investigated reforms to the transmission access framework as part of the Post-2025 Market Design project, including locational marginal pricing[36]. The Energy and Climate Change Ministerial Council decided not to pursue these reforms in 2023[37].

2.5 A transitioning system (present)

Electricity networks are increasingly shifting from traditional asset operators to platform operators, increasingly coordinating distributed and CER to improve efficiency, reliability and consumer value. Congestion and access constraints are tightening even as new transmission is built, and reliability as coal exits depends on timely delivery of new generation, storage and network projects. Regulatory reforms are enabling a more digitised, flexible and data-driven system. However, challenges persist around contestable participation, fair cost allocation, equitable access for consumers experiencing vulnerability, and ongoing reliance on safeguards such as the Default Market Offer.

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31 A Finkel, K Moses, C Munro, T Effeney and M O'Kane, *Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future*, Commonwealth of Australia, June 2017.

32 A Finkel, K Moses, C Munro, T Effeney and M O'Kane, *Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future*, Commonwealth of Australia, June 2017; AEMC, *Implementing the Independent review into the future security of the national electricity market (Finkel Review)*, AEMC, May 2018.

33 AEMC, *Access, pricing and incentive arrangements for distributed energy resources: Final rule determination*, AEMC, May 2021.

34 AEMC, *Review of the Wholesale Demand Response Mechanism*, AEMC, October 2025.

35 T Nelson, P Conboy and P Hirschhorn, *National Electricity Market Wholesale Market Settings Review: Final Report*, DCCEEW, December 2025.

36 AEMC, *Coordination of generation and transmission investment implementation – access and charging, Interim Report*, September 2020.

37 Energy and Climate Change Ministerial Council, *ECMC Communique*, 24 February 2023.

The present system is being shaped by rapid CER adoption, accelerating electrification and major shifts in generation and consumption patterns. Consumers are increasingly shaping the energy system by choosing how and when they use, store and supply electricity. Electrification of transport, heating and industry is increasing the economy's dependence on the electricity network, while renewable technologies (including rooftop solar, solar farms, wind and hydro) made up around 60% of NEM generation capacity in 2024, up from around 14% in 2014.[38]

Battery and electric vehicle uptake is increasing, intensifying two-way flow complexity and pushing distribution networks toward more active, platform-like roles reliant on improved DER visibility, flexible tariffs and orchestration to manage congestion and use capacity efficiently.[39]

Transmission remains central to reliability and renewable integration as coal exits, and higher shares of variable renewables and distributed generation are exposing legacy design limits (congestion, local constraints, volatility and minimum demand challenges), underscoring the need for stronger coordination across planning and network boundaries rather than siloed transmission, distribution and wholesale approaches. Distribution planning is further affected by fragmented data governance and sharing, while automation and third-party control of CER (for example via VPPs) is increasingly important for operational coordination.

New technologies and business models (such as EV charging, community scale batteries and flexibility services) are challenging the traditional boundary of distribution services and complicating service classification and ring-fencing waivers, especially where the coordination function spans the regulated–contestable interface rather than sitting clearly inside or outside the perimeter.

Equity concerns have become more prominent amid cost-of-living pressures and uneven CER uptake, with increasing attention on the distributional impacts of electricity pricing. There is growing concern about cost recovery risks as network costs shift toward a shrinking pool of non-CER consumers. This has elevated scrutiny of network tariffs,[40] access and non-network alternatives[41] and increasing reliance on retail safety nets for disengaged and vulnerable consumers.

In 2023 the NEO was amended to incorporate an emissions reduction factor, with policymakers emphasising that emissions reduction is an important component of the objective and consistent with efficient long-term consumer outcomes.[42] The Australian Government later increased its target for emissions reduction to a range of 62% to 70% reduction on 2005 emissions, reducing Australia's net greenhouse gas emissions to zero by 2050. This extended the previous emissions reduction target set in the Climate Change Act 2022 (Cth), which also included reducing Australia's net greenhouse gas emissions to zero by 2050.

The Energy Security Board was replaced by the Energy Advisory Panel in 2023, which maintained similar functions and membership. It comprises the heads of the Australian Energy Market Commission, the Australian Energy Market Operator, the Australian Energy Regulator, and the Australian Competition and Consumer Commission (as an observer only).

In December 2025, the Australian Government CER Taskforce also recommended that distribution NSPs be formally assigned a Distributed System Operator (DSO) role, reframing distribution networks

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38 AER, *An overview of an energy market in transition*, September 2025.

39 DCCEEW, *National Consumer Energy Resources (CER) Roadmap – Redefine roles for market and power system operations*, July 2025.

40 AEMC, *The Pricing Review: Electricity pricing for a consumer-driven future*, Market Review 2025

41 Non-network alternatives, or non-network options, are assets or services that provides an alternative to investment in transmission system apparatus, such as transmission lines or substations. They include, but are not limited to, battery storage, pumped hydro, synchronous condensers and

42 South Australia, *Parliamentary Debates*, House of Assembly, 14 June 2023 (Hon A Koutsantonis, Minister for Infrastructure and Transport, Minister for Energy and Mining).

as platforms for energy services and raising questions about how the coordination function should be governed beyond expenditure-focused tools.

As DSOs, distribution NSPs would coordinate and schedule CER to relieve local congestion and defer augmentation, improve system visibility through device-level data collection and sharing, and support system security by enabling DER to provide frequency, voltage and other stability services; they would also develop ways to reward households and businesses for providing flexibility when and where it delivers the most value.

Recent reforms include rule changes to accelerate smart meter deployment (mandating smart meters for all households and small businesses by 2030), improve real-time consumer data access, integrate price-responsive resources (making aggregated CER and demand response more dispatchable with supporting monitoring), and enable flexible trading for services such as EV chargers. AEMO established the Flexible Trading Arrangements (FTA) as part of the Post 2025 electricity market design, with the first release implemented on 31 May 2026.[43]

Alongside these transition measures, governments have increased the prominence of direct bill relief (for example, the Energy Bill Relief Fund, 2023–25) and reforms to strengthen the Default Market Offer as a safeguard for disengaged customers, including broader coverage, a guiding objective, an efficient-cost basis, tariff caps for common standing offers, and a regulated Solar Sharer Offer for midday free electricity for smart-meter households; together, these responses support a more flexible, data-driven and consumer-centric system while maintaining affordability and protections.

[43] AEMO *Flexible Trading Arrangements*, June 2026.

3 How we regulate networks in the NEM

Electricity networks – both transmission and distribution - and related services in the NEM are regulated to promote economic efficiency, maximise the welfare of Australians and achieve broader objectives for the long-term interests of consumers. The framework is comprised of legislation, rules and regulatory instruments, including the National Electricity Law (NEL), the National Electricity Rules (NER), and AER guidelines, instruments and decisions.

The framework combines economic regulation with conduct regulation. Economic regulation governs the terms on which regulated services are provided, including how efficient costs are assessed, how revenues are recovered, how prices are structured, and how regulated and non-regulated services are treated. Conduct regulation shapes how regulated service providers behave, including how they provide access to services, manage information, meet service obligations and comply with regulatory requirements.[44]

For economic regulation of electricity networks, the NEM adopts a hybrid incentive-based approach. Incentive-based regulatory models seek to replicate some of the profit-seeking discipline of competition while still retaining regulatory oversight of monopoly infrastructure.[45] In hybrid regulatory approaches, incentive-based mechanisms play a central role but are complemented by other forms of regulatory oversight and support mechanisms – for example, forward-looking price or revenue caps are commonly combined with measures such as performance incentives, benchmarking, service-quality schemes, reporting obligations and auditing requirements.[46]

In the current framework, services are first defined and classified, which is done to determine how different activities are treated and what form of regulation applies. This regulative approach is then implemented through ex ante revenue setting and supported by mechanisms such as uncertainty provisions, performance incentives and stakeholder engagement.

3.1 Key aspects of the regulatory approach

3.1.1 Service classification

The starting point for economic regulation of electricity networks in the NEM is determining whether a service meets the definition of a distribution or transmission service, and if so, how it is classified. Service classification determines the type of economic regulation, if any, that applies to services provided by NSPs. As discussed in Section 2, service classification defines the perimeter of the regulated business and provides the basis for later decisions about revenue-setting, pricing, ring-fencing and cost allocation.[47]

In distribution networks regulated services may be classified as standard control services, alternative control services or negotiated distribution services (see Figure 2). In practice, the AER generally classifies services in groupings rather than one by one, for example basic connections services include both residential and small business customers connections. This promotes consistency and gives networks some flexibility to adapt the exact specification of a service over time where its essential nature remains the same.[48] Services that meet the definition of a distribution service (which

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44 Norton Rose Fulbright, *Beyond law: Understanding the scope of conduct regulation,* April 2014.

45 S. P King, *Incentive regulation, benchmarking and utility performance,* Australian Competition and Consumer Commission (ACCC), November 2000.

46 The World Bank, *Rethinking Power Sector Reform in the Developing World*, 2019.

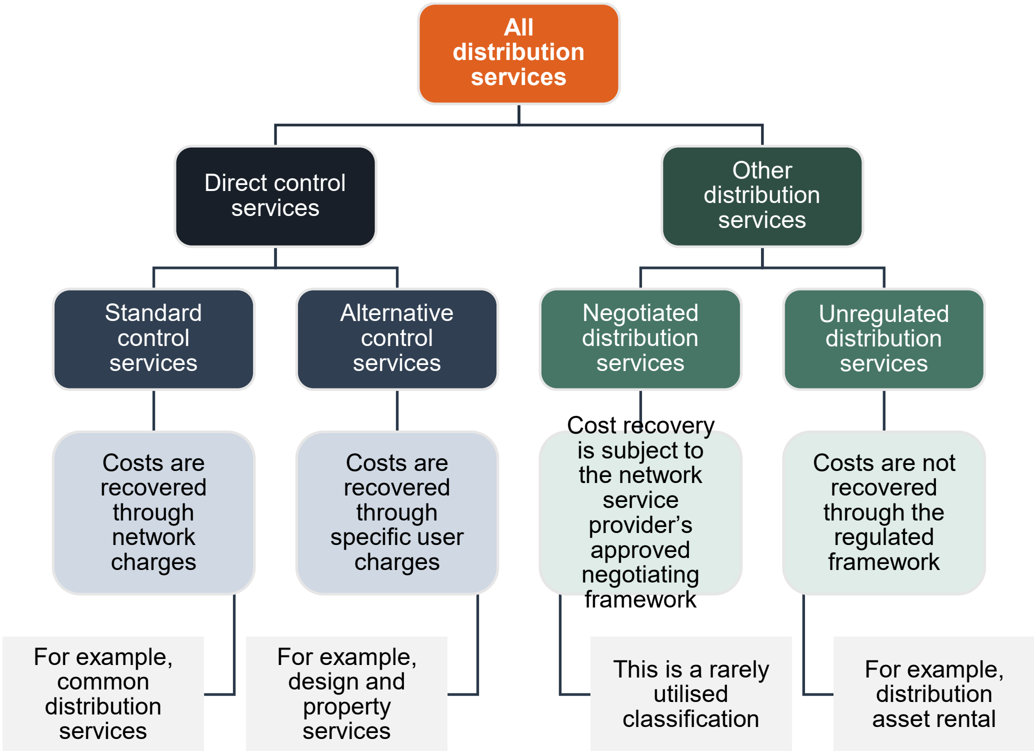
47 AER, *Electricity Distribution Service Classification Guideline*, Australian Government, August 2022.

48 AER, *Electricity Distribution Service Classification Guideline*, Australian Government, August 2022.

is ‘a service provided by means of, or in connection with, a distribution system’)[49] but that are not classified or fall within an existing service grouping are ‘unregulated distribution services’.

For distribution, classification decisions are made through the regulatory determination process for each distribution NSP. The AER sets out our initial views about service classification in our ‘framework and approach’ paper, which is published six months before a distribution NSP submits its regulatory proposal. Classification decisions are subsequently finalised as part of the distribution determination, usually for a regulatory period of 5 years.

Figure 2. AER distribution service classifications



For transmission networks, the classification framework in Chapter 6A of the NER sets out which types of services are treated as prescribed transmission services or negotiated transmission services. As such, in comparison to distribution services, the service categories and associated obligations for transmission services are more expressly structured through the rules, with the AER applying that framework in transmission determinations and related instruments.[50]

3.1.2 Boundary regulation

Boundary regulation governs how the framework manages the relationship between regulated services, non-regulated activities and adjacent markets. Building on service classification, it defines how service types are treated, how the regulated perimeter operates, and how NSPs engage outside it.

This aspect has grown in importance with new and emerging energy services. The AEMC’s 2017 *Contestability of Energy Services* rule change was a significant development because it clarified the treatment of behind-the-meter services and strengthened the separation between regulated network

49 National Electricity Rules, ch. 10.

50 National Electricity Rules, cl 6A.7.2, cl 6A.8.1 and cl 6A.9.1; National Electricity Law, s 7A.

functions and competitive energy services.[51] The AER's ring-fencing, cost allocation, shared asset and exemption guidelines give effect to this boundary, aiming to reduce cross-subsidisation, discrimination, market foreclosure, and misuse of monopoly advantages.[52]

Regulatory arbitrage risks are also increasing, as proponents may favour frameworks with faster decisions, better risk allocation, clearer access, or more direct policy support. Jurisdictional REZ frameworks can provide more prescriptive pathways than the NER framework. While this may support faster delivery, it can also create tension where overlapping regulatory regimes produce different answers to similar investment, access or cost allocation questions. This heightens the need to assess whether they deliver faster decisions and/or more efficient, durable outcomes.

The AER also uses regulatory sandboxing as a more flexible boundary tool. Through the Energy Innovation Toolkit, trial waivers can temporarily relax requirements under conditions such as consumer protections, reporting and time limits, allowing innovative business models and technologies to be tested while preserving accountability and generating evidence about whether more enduring regulatory change may be warranted.[53] The AER's policy-led sandboxing initiative is also relevant, as it considers how regulatory settings can better support access to deployment and orchestration of the CER and DER. This gives the AER a way to test some of these issues in practice, rather than only considering them at a policy level, while keeping the consumer protections and reporting requirements in place.

3.1.3 Incentive-based regulation as the core approach

The current approach to regulating prescribed and standard control services provided by electricity networks in the NEM is best understood as a form of incentive regulation applied to monopoly infrastructure.

Unlike earlier models like rate-of-return regulation, which tie revenues more closely to realised costs and focus more on cost recovery, incentive regulation sets revenues in advance and allows businesses to retain some of the benefits of cost savings until the next reset.[54] Conversely, businesses also bear some of the consequences if costs exceed allowances or performance falls short, including lower profits, penalties under service performance schemes, and the risk that inefficient expenditure will not be recovered from customers through mechanisms like ex post reviews.

Setting forward-looking allowances and exposing networks to the consequences of how actual costs and performance compare over the regulatory period aims to replicate a competitive market,[55] encouraging monopolies to reduce costs, improve efficiency and innovate. It also reduces information asymmetry by revealing efficient costs over time, which can inform future regulatory determinations so that consumers benefit over time from improved efficiency.[56]

Within this framework, gains and losses against forecast expenditure are shared by the NSP and consumers, rather than borne entirely by one party. Sharing mechanisms allocate underspends and overspends with the Efficiency Benefit Sharing Scheme (EBSS) for operating expenditure and the Capital Expenditure Sharing Scheme (CESS) for capital expenditure allows NSPs to retain a portion of

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51 AEMC, *National Electricity Amendment (Contestability of energy services) Rule 2017,* Australian Government, 2017.

52 AER, *Ring-fencing Guideline (Electricity Distribution) Version 4,* Australian Government, 2025.

53 AER, *About Regulatory Sandboxing trials*, Australian Government, 2025.

54 P.L Joskow, *Incentive Regulation in Theory and Practice: Electricity Distribution and Transmission Networks,* Massachusetts Institute of Technology (MIT), 2006.

55 R Nepal, F Menezes, & T Jamasb, *Network Regulation and Regulatory Institutional Reform: Revisiting the Case of Australia*, Energy Policy, pp. 73, 259–268. 2014.

56 AER, *Better Resets Handbook,* Australian Government, July 2024; AER, *Review of incentive schemes for regulated networks*, Australian Government, 2023.

efficiency gains, while also exposing them to a share of any overspend. This helps preserve incentives to manage total expenditure efficiently during the regulatory period, while ensuring that consumers benefit over time.

Reliability inputs, such as the Value of Customer Reliability, Value of Network Resilience and Value of Emissions Reduction, help assess the trade-offs between the cost of network investment and the outcomes consumers value. These parameters provide a more consistent basis for assessing expenditure and service levels by helping to weigh different dimensions of the long-term interests of consumers.

These incentives and trade-offs are given effect through the revenue determination framework under the National Electricity Rules. This begins with NSPs engaging with their customers and stakeholders to develop proposals which the AER then assess against the rules, consultation and relevant guidance.

Once submitted, the AER must assess the NSP’s proposal against specified criteria and accept the proposal if it is satisfied that it reasonably reflects prudent and efficient costs, realistic demand forecasts, and other requirements in the Rules. Where the AER is not satisfied, it may substitute its own estimate, but only in line with NER framework and relevant factors.

Through this process, the AER determines efficient expenditure and the maximum revenue that networks can recover over a five year regulatory control period.[57] Once the AER determines the maximum allowed revenue, it must also apply the relevant form of control that governs how that revenue is recovered and translated into annual prices, noting this is determined before a network submits any expenditure proposal.

For transmission, Chapter 6A of the NER requires a revenue cap, with pricing focused on allocating revenues.[58] In contrast, the NER allow a range of control mechanisms for direct control distribution services, for example revenue caps, price caps, tariff basket controls or other control mechanisms allowed in under the Rules.[59]

In deciding on a control mechanism for these services, the AER must consider a range of factors such as the need for efficient tariff structures, administrative costs, impact on potential competition, and consistency over time or across similar services.[60] The chosen mechanism affects the allocation of risk and the incentives the business faces in relation to pricing, demand and expenditure decisions over the regulatory period.[61]

Under a weighted average price cap, the regulator constrains the average prices rather than total revenue, so actual revenue varies with prices and services volumes.[62]

Under a revenue cap, the total revenue to be recovered is fixed for the regulatory period, with prices adjusted annually to recover that amount. Because revenue is decoupled from demand, the network does not gain from higher volumes or lose from lower volumes within the period, thereby removing the volume-driven revenue incentive that operates under a weighted average price cap. Incentives for cost-efficient delivery are preserved through other incentive mechanisms, namely the CESS and

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57 Outside of these determinations and the maximum allowed revenues set in that context, transmission NSPs and distribution NSPs may also recover other revenues e.g. for cost pass throughs, jurisdictional schemes, etc.

58 National Electricity Rules, cl 6A.4.2(b).

59 National Electricity Rules, cl 6.2.5(c).

60 National Electricity Rules, cl 6.2.5.

61 AEMC, *Network regulation*, (n.d.)

62 P.L Joskow, *Incentive Regulation in Theory and Practice*, MIT, 2006.

EBSS. As a result, revenues under this form of control are less sensitive to changes in demand and utilisation. In practice, the AER has decided to apply a revenue cap to all distribution NSPs.

In addition to the core revenue-setting approach, the NEM's incentive-based framework relies on mechanisms to make the incentives work in practice and allow the AER to manage demand uncertainty. A core feature of the model is the periodic reset, usually every 5 years, through which the AER reassesses efficient expenditure and revenue requirements in light of updated forecasts, changed circumstances and information revealed during the previous period. This reset process is central because it allows networks to retain some gains or losses within a regulatory period, while enabling revealed costs and performance to inform future allowances ensuring customers are better off over time.[63]

The framework is also supported by benchmarking, operational and financial performance reporting, service quality obligations, licensing conditions and performance-based incentive schemes. These mechanisms help test expenditure proposals and forecasts, monitor performance, moderate information asymmetries and provide confidence that apparent outperformance reflects genuine efficiency rather than forecast error, deteriorating service standards or non-compliance.[64] Together, these features reflect a central challenge in incentive regulation – stronger incentives can sharpen cost discipline and improve productive efficiency, but they can also create tension with other objectives, including service quality and longer-term dynamic efficiency. In particular, a framework that places strong pressure on businesses to contain expenditure within a regulatory period may weaken incentives for efficient long-term investment, innovation or other expenditure the benefits of which emerge over a longer time horizon.

Innovation often involves greater short-term costs or risks, while benefits may be uncertain or emerge only over a longer period (for example, in future regulatory periods). This can reduce the incentive for a network business to pursue innovative approaches where it bears the near-term costs but may capture only part of the long-term benefits. The framework therefore seeks to balance short-term efficiency incentives with the need to maintain service standards, support efficient long-term investment, and ensure that consumers benefit over time from information revealed through regulatory practice.[65]

3.1.4 Incentives operationalised through the building block model

The building block approach is the principal mechanism through which incentive regulation is applied. It starts from the proposition, embedded in the NEL,[66] that a regulated network business should be allowed a revenue stream sufficient to recover the prudent and efficient costs of providing regulated services. The AER determines at the start of the regulatory period the revenue an efficient network business would need to provide those services.[67]

The main 'building blocks' on which allowed revenue is based are:

- forecast efficient operating expenditure (opex)
- return on capital
- regulatory depreciation (return of capital)
- corporate income tax allowances

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63 AER, *Better Resets Handbook*, July 2024.

64 AER, *Review of incentive schemes for regulated networks*, 2023.

65 AER, *Review of incentive schemes for regulated networks*, 2023.

66 National Electricity Law, s 7A(2).

67 AER, *Overview of the Better Regulation reform package*, Australian Government. April 2014.

- relevant incentive adjustments.

Under this approach, allowed revenue is significantly impacted by an NSP's Regulatory Asset Base (RAB). Return on capital is calculated by applying the allowed rate of return to the RAB.[68] The rate of return is based on a benchmark efficient entity rather than the actual capital structure or financing costs of a particular NSP.[69] Regulatory depreciation provides for the return of capital over time. The RAB is rolled forward between regulatory periods by taking the existing asset base, indexing it for inflation, adding actual capital expenditure incurred during the regulatory period, and subtracting regulatory depreciation. This approach supports predictability and stability in how capital is returned over time, although the AER may determine a different approach as part of a determination. As a result, efficient capex is recovered over the life of the asset through a combination of depreciation and return on capital, while opex is recovered within the period in which it is incurred.[70]

An efficient rate of return compensates for only the systematic risk of investing in a firm supplying energy network services, since non-systematic risk can be mitigated by holding a diversified portfolio. While non-systematic risks are considered in the overall return in the regulatory framework, they are compensated through means outside the allowed rate of return. For example, regulation reduces uncompensated risks by allowing cost pass throughs for non-systematic risks, such as industry-specific tax changes or geographic-specific natural disasters.

The framework therefore determines which costs may be recovered through regulated revenues, the period over which those costs are recovered, and the way risks and incentives are allocated between consumers and NSP.[71] For services subject to building block regulation, the framework sets total forecast capex and opex allowances for the regulatory period and leaves the NSP to determine how best to deliver the required services within those allowances.[72] Once allowances are set, the NSP has a financial incentive to manage costs efficiently, while remaining exposed to part of the difference between forecast and actual expenditure.[73]

The treatment of capex in the building block model has received persistent criticism over time. Under the framework, capital investments are treated differently to operating costs. Capex can be added to the regulatory asset base and recovered over time, with a return on that investment. Opex is generally recovered as a cost allowance, so networks recover the cost but do not earn a return on it in the same way. As such, stakeholders have raised concerns that the framework can bias toward capital solutions over operating or procured alternatives.[74] This separation between capex and opex within the building block model can also make it more complex to assess alternative solutions on a neutral basis where the efficient response may involve a combination of network investment, network operating expenditure and the NSP contracting services (including demand management, flexible distributed resources or services from long lived assets such as large scale storage).

There are also challenges in identifying when non-network options are viable and efficient, which can depend on whether potential alternatives are visible to the NSP, how they are assessed, and the extent to which the regulatory framework supports their consideration at the right time and on a

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68 National Electricity Rules, cl 6.4.3 and cl 6A.5.4.

69 AER, *Rate of return and assessing the long term interests of consumers. Position Paper*, Australian Government, 21 May 2021.

70 Australian Energy Regulator, *Consumer information session: The Building Block Model*, November 2017.

71 AER, *Better Resets Handbook*, Australian Government, July 2024.

72 National Electricity Rules, cl 6.5.6 and cl 6.5.7.

73 AEMC, *Chapter 6: Economic regulation of distribution services*, 2021.

74 Brattle Group, *Incentive Mechanisms in Regulation of Electricity Distribution: Innovation and Evolving Business Models*, October 2018; Nexa Advisory, *Submission to VIC 2026–31 DNSP determinations*, January 2026, p 27.

comparable basis. This has led to concern that the current model biases conventional network augmentation over alternatives that may lower costs.[75]

The AER and broader regulatory framework have sought to address this issue through mechanisms intended to improve the consideration of non-network options and better align incentives with efficient outcomes. These include the Regulatory Investment Tests for Transmission and Distribution (RIT-T and RIT-D) processes, demand management and incentive arrangements, and more recent changes to the network support pass through arrangements and associated AER guidelines.[76] More recent changes also go to how some non-network support arrangements are assessed and recovered, including contract review and cost recovery outside the usual building block process where needed. Together, these mechanisms are intended to improve the visibility and assessment of non-network alternatives. However, some stakeholders have suggested that capex bias remains a material issue, particularly in distribution, where the framework may still favour traditional network investment over non-network alternatives, including demand-side solutions, flexibility services and aggregated CER/DER.[77]

The framework can also affect incentives to pursue innovation. Innovative approaches (such as new technologies, operating models or market-based solutions) often involve higher or more uncertain costs in the near term, while the benefits (such as avoided augmentation, improved utilisation or lower system costs) may materialise over a longer timeframe or in future regulatory periods. In these circumstances, the NSP may bear the upfront cost and risk within the current period, while a portion of the benefits is either uncertain or reflected in future allowances and therefore passed through to consumers over time. This may weaken incentives to pursue innovative or non-traditional solutions over more predictable, conventional investments.[78] However, recent mechanisms to support innovation, including innovation-related capex allowances and demand management incentive arrangements were designed to help reduce some of these barriers by giving more explicit pathways for NSPs to explore new approaches and recover efficient costs, noting that consumers will fund this allowance and therefore bear the risk associated with the innovation. Questions remain about whether these arrangements have delivered as expected, including issues raised by stakeholders about their use and effectiveness.[79]

Finally, the economic regulatory framework incentivises transmission NSPs to proactively identify and manage project risks ex-ante to reduce the risk of cost overruns being passed onto consumers. In 2021, the AER developed a guidance note to improve the predictability and transparency of how we will assess the costs of large transmission projects.[80] This guidance note stated that the AER can accept a project risk allowance in a contingent project application by assessing the residual risks identified by the transmission NSP, and the efficiency of the associated cost estimates (i.e. the consequential cost adjusted to reflect the likelihood of occurrence).

3.1.5 Performance-based incentive schemes

The performance incentive schemes sit alongside the building block model to address dimensions of network decision-making that a pure expenditure allowance framework does not fully capture or

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75 Frontier Economics, *Why TOTEX? A discussion paper,* Energy Networks Australia, 2018.

76 AER, *Regulatory Investment Test for Distribution application guidelines,* Australian Government, November 2024.

77 Brattle Group, *Incentive Mechanisms in Regulation of Electricity Distribution: Innovation and Evolving Business Models*, October 2018; Nexa Advisory*, Submission to VIC 2026–31 DNSP determinations.* January 2026.

78 AEMC, *Perspectives on the building block approach – Review into the use of total factor productivity for the determination of prices and revenues,* AEMC, 30 July 2009, page 8.

79 AER, *Incentivising and measuring export service performance – Final report*, March 2023, pp. 19–20.

80 AER, *Regulation of large transmission projects - Final decision,* March 2021.

ensure that lower expenditure is aligned with outcomes that consumers value. The role of performance incentive schemes is therefore to shape behaviour in ways that are important for long-term efficiency, including service performance, expenditure timing, and the consideration of non-network alternatives. These schemes are designed to mimic the profit seeking motives inherent in competitive markets by ensuring that consumers pay no more than necessary for services they value. These schemes are also intended to preserve incentives through the regulatory control period and to prevent those incentives from weakening as the next reset approaches.[81]

In the current framework, the main incentive schemes are the Efficiency Benefit Sharing Scheme (EBSS) for opex, the Capital Expenditure Sharing Scheme (CESS) for capex, and the Service Target Performance Incentive Scheme for service performance. Incentive schemes that only apply to distribution networks include the Customer Service Incentive Scheme and the Demand Management Incentive Scheme.[82]

In 2023, the AER reviewed the incentive schemes for regulated networks and found that:

- Specific parts of the transmission network Service Target Performance Incentive Scheme, required further review because historic baselines were becoming less reliable in a system with rising congestion and changing generation patterns.
- It would retain the Demand Management Incentive Scheme (which applies only to distribution networks) and the Demand Management Innovation Allowance Mechanism, providing funding for trials and projects to develop non-network solutions.
- The EBSS was working as intended and should be retained, reflecting the fact that opex is relatively recurrent and better suited to a revealed-cost approach.
- The CESS raised more significant issues because capex is often lumpy, non-recurrent and project-specific, making underspends harder to interpret and more susceptible to forecast error.

The AER retained the CESS but introduced a Bright-Line Tiered Test[83] that reduced rewards for larger capex underspends, maintained symmetrical treatment of overspends, and added transparency requirements to help distinguish genuine efficiency from over-forecasting.[84]

This review highlighted that the incentive schemes form an integral part of the NEM's hybrid incentive-based framework and have been recalibrated over time to maintain the balance between efficiency incentives, consumer outcomes and the changing dynamics of network operation.[85]

3.1.6 Ex ante with ex post monitoring

Ex ante regulation involves setting rules, allowances or incentives in advance of a regulatory period, typically based on forecasts, assumptions about efficient costs, demand and performance. In the NEM, the AER sets expenditure allowances, the allowed rate of return, depreciation, forecast tax allowances and the form of control at the start of the regulatory period, which are reset every 5 years.

The central revenue decision is made on the basis of forecast efficient costs rather than actual incurred costs. The NSP then bears the consequences of over- or under-spending during the

81 AER, *Review of Incentive schemes for regulated networks*, Australian Government, April 2023.

82 AER, *Review of Incentive schemes for regulated networks*, Australian Government, April 2023.

83 AER, *Review of Incentive schemes for regulated networks*, Australian Government, April 2023, p. 3. A bright-line rule (or bright-line test) is a clearly defined rule or standard, composed of objective factors, which leaves little or no room for varying interpretation.

84 AER, *Review of Incentive schemes for regulated networks*, Australian Government, April 2023.

85 IBID.

regulatory period, subject to pass throughs, contingent projects, capex re-openers and relevant incentive mechanisms.

This ex ante design is intended to create stronger incentives for cost discipline, encourage businesses to search for more efficient ways of delivering regulated services, and reduce the extent to which the regulator is drawn into a continual cost-by-cost review. It also gives the NSP flexibility to determine how best to deliver the required service outcomes, including those identified in the network engagement process, within the allowed revenue envelope. Within this envelope, NSPs can manage and reprioritise expenditure across their approved allowances during the regulatory period, which gives them scope to respond to changing circumstances without needing each expenditure project to be approved by the regulator. As such, it is intended to cap monopoly prices while leaving firms to make day-to-day expenditure and operational choices during the regulatory period.[86]

However, the effectiveness of this approach in revealing efficient costs can differ across expenditure types, particularly as demand patterns, connection activity and network investment needs become less predictable. This differs from earlier periods, where demand could often be assessed against historical trends and established planning assumptions. The issue now is that past trends may be a less reliable guide to what networks will need next, especially with electrification, changing connections and more distributed energy connected to the system. As demand becomes more variable, the characteristics of demand-driven expenditure become more important. In particular, demand-driven expenditure (network augmentation, customer connections, etc) is often lumpy, non-recurrent and project-specific, which can make underspends harder to interpret and more susceptible to forecast error compared to more recurrent-in-nature expenditure.[87]

The NEM regulatory model also adopts a range of ex post monitoring tools. Ex post regulation involves assessing actual behaviour or outcomes after the fact, through mechanisms such as monitoring, reporting, compliance, benchmarking and targeted reviews. In the NEM, these allow the AER to test actual performance, revealed costs and compliance over time.

In practice, the model is therefore best understood as ex ante revenue-setting supported by targeted ex post oversight and review. The ex ante elements support efficiency incentives by allowing NSPs to retain gains from outperformance or bear part of the cost of underperformance within the regulatory period. The ex post elements support accountability, provide information about how the framework is operating in practice, and help test whether observed outcomes reflect efficient performance, inefficient expenditure or non-compliance.[88] Together with periodic resets, uncertainty mechanisms and the use of revealed information in future determinations, these features help the framework respond to changing circumstances while preserving the core incentive properties of the regime.

3.1.7 Uncertainty mechanisms

Uncertainty mechanisms help allocate risk within the regulatory period by allowing certain changes in circumstances to be addressed without reopening the entire determination. They play an important role in the NEM's ex ante framework by recognising that actual costs, project timing and system conditions may evolve over the course of the regulatory period. These uncertainty mechanisms are becoming increasingly important in the context of the energy transition.

In the NEM, these uncertainty mechanisms include cost pass throughs for unforeseen but prescribed events that are beyond the reasonable control of a network business, such as new statutory

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86 Productivity Commission, *Electricity Network Regulatory Framework Productivity Commission Inquiry Report*, Australian Government, April 2013.

87 AER, *Review of Incentive schemes for regulated networks*, Australian Government, April 2023.

88 The AERs Capital Expenditure Incentive Guidelines (2025) makes this balance clear by stating that the ex post measures are intended to ensure that network users do not bear the costs of inefficient or imprudent overspends, capitalised opex or inflated related-party margins.

obligations or natural disasters, and which have not been accounted for in its current 5-year revenue determination (subject to materiality thresholds). The AER assesses the application and makes a cost recovery determination based on the principle that consumers should pay no more than necessary for safe and reliable energy.[89] Over time, changing interpretations of the cost pass through criteria have lowered the threshold for triggering pass through applications. This has expanded the circumstances in which NSPs may seek additional revenue during a regulatory period and has subsequently increased the number of pass through applications received by the AER.

Other mechanisms include contingent projects, which can be foreseen as reasonably required under specific circumstances, but which are excluded from an NSP's general capital expenditure allowance because of uncertainty about when or whether they will be needed during the regulatory period. The contingent projects mechanism in the NER recognises that, unlike competitive businesses which can adjust their behaviour in response to uncontrollable factors, a NSP is generally obliged to continue to supply services, even where their network is exposed to significant risks.

In comparison to a cost pass through, contingent projects are intended to apply to matters that are more specific to a particular set of conditions than a pass through event. To be accepted as a contingent project in a determination, a project must have clearly defined trigger events which, if it occurs during the regulatory period, allows a network business to recover incremental revenue during the period based on the capital and incremental operating expenditure reasonably required for the purpose of undertaking the project.[90]

In some cases, the NER also allows for an NSP to apply to the AER to reopen its regulatory determinations to adjust approved capital expenditure where specific and targeted criteria (and materiality thresholds) under the NER are met and, if so, what adjustments to its approved capital expenditure and revenue recovery from customers are appropriate.[91]

These mechanisms are important because they reduce some of the risk that NSPs would otherwise bear under a purely forward-looking framework. Uncertainty mechanisms thus preserve the overall incentive-based structure of the determination while introducing more cost-of-service-like treatment where strict reliance on ex ante allowances would allocate risk inefficiently or create poor outcomes.

Growing network resilience risks, changing patterns of demand, and evolving transmission and distribution needs associated with the energy transition all make it harder to forecast efficient costs and project timing with confidence at the beginning of the regulatory period. This raises a further question about whether the current suite of mechanisms is sufficient, or whether additional or differently calibrated pass through and reopening tools may be needed to respond to future uncertainty.

3.1.8 Investment assessments and non-network alternatives

To ensure network investments are in the long-term interests of consumers, the NEM regulates major network augmentation and replacement projects through investment assessments. These assessments involve a combination of analytical requirements and consultation obligations, which are intended to test assumptions, identify credible alternatives, and provide transparency to stakeholders. Different processes apply depending on how the need for investment is identified.

At the transmission level, AEMO undertakes whole-of-system planning through the ISP process. Where a project is identified as an actionable ISP project, the relevant transmission NSP must apply

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89 AER, *Cost pass throughs,* Australian Government, July 2023.

90 United Energy*, Managing uncertainty (UE Att 11.01 – Public),* United Energy, January 2025.

91 AER, *AER begins consultation on Transgrid's application to reopen the 2023–28 transmission revenue determination for Project EnergyConnect,* Australian Government 27 March, 2026.

the RIT-T in accordance with the AER's Cost Benefit Analysis Guidelines.[92] Separate project assessment processes apply where augmentation or replacement needs are identified by NSPs themselves. In those cases, both transmission NSPs and distribution NSPs must apply the relevant investment test to projects above the applicable threshold, using a RIT-T or RIT-D and associated guidelines.[93][94]

The RIT-T and RIT-D are designed to ensure that network investment is subject to a transparent and structured comparison of credible options. For transmission, the RIT-T requires publication of a Project Specification Consultation Report, which sets out the need to be addressed and the requirements that a non-network option would need to meet. For distribution, the RIT-D requires an options screening process, including publication of an options screening report, consultation on credible alternatives, and justification of the preferred option through a formal cost–benefit assessment. These processes are intended to ensure that capital network investments, including augmentation, and replacement expenditure above the relevant thresholds, are not preferred by default and that non-network options are considered on a comparable basis where these are capable of meeting the identified need.[95]

Together, these mechanisms seek to improve the visibility and assessment of non-network alternatives within network planning. To further enable the implementation of non-network options, the AER's Network Alternative Support Payment Guideline applies to transmission NSPs and provides guidance on the treatment of payments to non-network option providers, including how such payments may be recovered through the regulatory framework once a preferred option has been identified.[96] These aspects of the regulatory framework all form part of the broader regulatory approach to ensuring that investment decisions reflect efficient and least-cost outcomes over time.

3.1.9 Pricing and network use

While the above aspects of the regulatory framework shape the overall risks and incentives NSP face, the framework also recognises the role of pricing in reducing costs, promoting efficient use of the network, and allowing recovery of efficient costs – outcomes that are reflected in the pricing principles in the NER.[97]

A Tariff Structure Statement lays out the tariff structures and assignment policies for the regulatory period, and the *indicative* prices for those tariffs for each year of the regulatory period. It is supported by a tariff strategy, which helps explain how the proposed tariffs link back to the broader regulatory proposal, including expected demand, customer behaviour and the need for network investment. Distribution NSPs' Tariff Structure Statement development is informed by stakeholder engagement with distribution NSPs required to describe how they have engaged with customers and retailers in developing the proposed Tariff Structure Statement.[98] Distribution NSPs must then submit annual pricing proposals for approval each year of the regulatory period, setting out the actual prices that will apply for the network tariffs for the coming year and how they are consistent with the Tariff Structure Statement.

For transmission, the framework governs the methodologies used to allocate allowed revenue across transmission customers and regions, including the treatment of shared network costs and inter-regional pricing arrangements. The AER's role therefore extends to ensuring that the transmission NSP's transmission pricing methodologies comply with the specific allocation and pricing rules set out

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92 AER, *Cost Benefit Analysis guidelines*, Australian Government, November 2024.

93 AER, *Regulatory Investment Test*, Australian Government, November 2025.

94 AER, *System Security Network Support Payment Guideline*, Australian Government, November 2024.

95 AER, *Regulatory Investment Test*, Australian Government, November 2025.

96 AER, *AER – Network alternative support payment guideline*, Australian Government, 13 March 2026.

97 AER, *Chapter 6: Economic regulation of distribution services*, Australian Government, (n.d.).

98 National Electricity Rules, cl 6.8.2(c1)(c2)

in the NER. Relative to distribution, this means the AER's role in relation to transmission pricing is much more limited, as there is no annual process where transmission NSPs submit annual pricing proposals to the AER for approval.

This pricing function is becoming more important as network use becomes less predictable and more responsive to changing network and market conditions and consumer participation in the energy market through consumer energy resources continues to grow. Instruments such as the Export Tariff Guidelines and Export Limit Guidance Note show how regulation of tariffs and operational settings increasingly shapes access to network capacity, export services and CER integration.[99][100] Indeed, network tariffs are one of the main ways the regulatory framework influences how scarce network capacity is allocated, how costs are signalled to retailers (in the case of small customers) or large users, and how regulation can remain adaptive to more active and flexible use of distribution networks.[101][102]

3.1.10 Consumer protections and service obligations

In addition to protecting consumers from unnecessarily high prices through economic regulation, the framework also includes a set of consumer protection obligations that govern how NSPs interact with customers in delivering essential services. These obligations are typically set out in the National Energy Retail Rules (NERR) and related instruments and include requirements relating to notification of planned and unplanned outages, the provision of information to customers, and communication of changes that may affect service delivery. These mechanisms play an important role in ensuring that customers receive relevant and timely information, are able to understand and respond to changes in service and are protected from adverse impacts associated with network operations. Connection agreements and model standing offers also matter here, as they can affect how customers use their assets and appliances, including through technical settings or dynamic capacity such as flexible export limits.

The framework also includes service obligations to ensure a level of performance and reliability of network integrity. These obligations include system strength requirements for transmission networks as well as jurisdictional reliability standards and licensing conditions. Together, these obligations complement the broader regulatory framework by embedding minimum standards of transparency, communication and service into how network services are delivered.

3.1.11 Regulatory process and stakeholder engagement

Stakeholder engagement is a procedural and governance mechanism that supports the operation of the broader regulatory framework. By law, the AER is required to consult in a range of regulatory processes under the NEL and NER, including revenue determinations, guideline reviews and other decisions that affect NSP and consumers. More broadly, stakeholder engagement is a crucial part of evidence-based regulatory and policy decision-making. It improves the information available to the regulator, reduces information asymmetry between stakeholders, tests network proposals and regulatory assumptions, strengthens transparency, legitimacy and accountability, and brings consumer preferences and practical implementation issues into determinations and decisions.

The current revenue determination process is based on a 'propose–respond' model, where NSPs submit regulatory proposals to the AER, which the AER assesses, accepts or substitutes in part. The AER's assessment role is constrained by the legal framework. In electricity, the AER must assess

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99 AER, *Export tariff guidelines*, Australian Government, 2022.

100 AER, *Export Limit Guidance Note*, Australian Government, 2024.

101 AER, *Export Limit Guidance Note*, Australian Government, 2024.

102 AEMC, *The Pricing Review: Electricity pricing for a consumer-driven future*, 2026.

proposals against the criteria and decision-making requirements set out in the NEL and NER, and its ability to substitute alternative amounts or approaches depends on the circumstances and evidence before it. This means the AER does not simply 'set' revenues in an unconstrained way, even where it has concerns about aspects of a proposal.

This model recognises that NSPs operate the network and hold much of the relevant information, meaning they are well placed to develop the initial proposal. However, earlier reviews identified that this model can also reinforce information and resource asymmetries because the NSP frames the proposal and provides the supporting material that the AER, consumers and other stakeholders must then test. The 2015 Senate inquiry into the performance and management of electricity network companies described concerns that the propose–respond model allowed networks to 'frame the discussion', submit very large volumes of technical material, and make it difficult for consumers and other stakeholders to engage effectively. The inquiry also linked these issues to concerns about information asymmetry, incentives to 'game' the regulator, and the former merits review framework.[103]

These concerns have informed subsequent changes to the reset process. The AER's Better Regulation reforms and the establishment of the Consumer Challenge Panel sought to bring consumer perspectives more directly into revenue determinations. More recently, the Better Resets Handbook and early signal pathway have sought to improve the operation of the propose–respond model by encouraging earlier engagement, draft proposals, and giving consumer panels a pathway to provide their own findings separately from the network, and clearer evidence where consumer preferences have shaped proposals before they are formally lodged. This reflects a broader shift away from highly technical and adversarial reset processes toward more transparent, iterative and consumer-informed engagement.[104]

3.1.12 Compliance and enforcement

Compliance and enforcement mechanisms aim to complement the predominantly incentive based framework to achieve the desired outcomes. They provide the means for the AER to monitor whether regulated businesses are meeting their obligations, responding to non-compliance, and promoting confidence that the energy markets are working effectively and in the long-term interests of consumers.

The AER is responsible for monitoring, investigating and enforcing compliance with obligations under the NEL, NER, National Energy Retail Law and National Energy Retail Rules, and AER enforceable guidelines. The AER's Compliance and Enforcement Policy states that this role is directed to encouraging compliance, addressing and deterring non-compliance, holding parties to account and achieving broader deterrence across the market. The AER uses a risk-based approach, supported by annual compliance and enforcement priorities, and may use tools such as monitoring, information requests, audits, infringement notices, enforceable undertakings and court proceedings.

3.2 Key regulatory instruments

The regulatory model is implemented through a layered set of legal obligations, rules, guidelines, methodologies, determinations and processes, rather than through a single law, rule or decision. Collectively, these instruments shape how the AER makes decisions, how NSPs understand and meet their obligations, how regulatory proposals are developed and assessed, and how stakeholders engage with, test and interpret regulatory outcomes.

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103 Senate Environment and Communications References Committee, *Performance and management of electricity network companies: Interim report*, Parliament of Australia, April 2015.

104 Energy Networks Australia, *AER engagement reset a win for all*, Energy Networks Australia, 28 October 2021.

The NEL provides the statutory foundation for the regulation of electricity transmission and distribution services across the NEM. Based on that foundation, the NEL and NER establish objectives, institutional roles, core regulatory principles and key decision criteria, while the more detailed operation of the framework is carried through a wider set of regulatory methodologies, guidelines, determinations and processes developed and applied by the relevant institutions.

At a broad level, the tools perform two related functions. First, they contain the substantive requirements that determine how regulation applies in individual cases. The core rules are contained in the NER, while more detailed methodologies may be set out in the Rules and, where the framework provides for discretion, in AER guidelines and guidance.

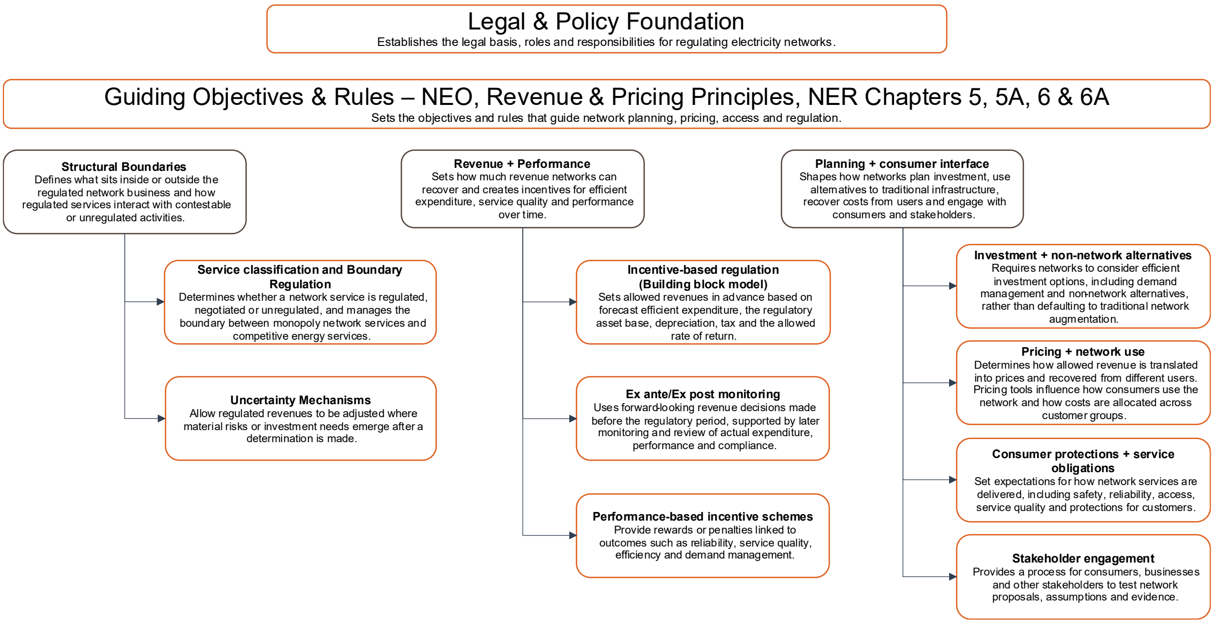
Some guidelines made under the NER are binding and enforceable (for example, the ring-fencing guideline), while others provide guidance on how the AER will exercise its discretion (for example, service classification and cost assessment approaches). Together, these cover matters such as service classification, expenditure assessment, rate of return decisions, incentive design, cost allocation, pricing and investment assessment.

The tools also contain the procedural rules and governance mechanisms that determine how decisions are made. This includes consultation requirements, information and reporting obligations, approval processes, compliance arrangements and the circumstances in which the regulator may exercise discretion.

A central feature of the NEM approach has been to balance codification and discretion of regulatory instruments. Some instruments of the framework are set out in relatively prescriptive terms because they need to be known in advance, applied consistently across businesses, or provide a stable basis for long-term investment and regulatory administration. Conversely, other instruments are left to regulatory judgment so that NSP and the AER can exercise a degree of flexibility when responding to evolving system conditions. Over time, the rules have developed as either highly prescriptive or allowing for more discretion across different parts of the building block model and associated regulatory tasks. This has been accompanied by the development of more detailed regulatory guidance in areas where the law provides for discretion, but where transparency, predictability and consistency remain important.

Figure 2 shows the key instruments that give effect to the regulatory framework, with a fuller description contained in Appendix A. This is not intended to be a comprehensive review of all AER guidelines, guidance notes or related regulatory instruments. Rather, it focuses on instruments most relevant to the preceding discussion in this paper.

Figure 3: Key elements of the electricity network regulatory framework



4 What we regulate in the NEM

As set out in Section 3.1, service classification determines the type of economic regulation, if any, that applies to services provided by NSPs. This section explores how the scope of services provided by NSPs has changed over time to shape what we regulate today, and how recent service classification decisions can provide insight into how the role of NSPs may change into the future.

4.1 Distribution

4.1.1 What is a distribution service?

A 'distribution service' is defined in the NER as a service provided 'by means of, or in connection with, a distribution system'.[105] This definition is broad and market bodies have previously considered whether it should be clarified.[106] For example, in 2016, the AEMC consulted on whether this definition provides clear guidance on which services are distribution services and which are not. The AEMC considered that introducing a functional characteristic into the definition of 'distribution services' would reduce the AER's discretion without improving clarity. The AEMC concluded that improvement in clarity, transparency and regulatory predictability is best achieved through the AER's publication of the service classification guideline.[107]

In 2018, the AER consulted on how the definition of a distribution service should be interpreted in developing the Electricity Distribution Service Classification Guideline, in the context of emerging technologies and ancillary-service markets. The AER noted that the statutory definition had been contentious and that stakeholders had criticised the definition as being vague and imprecise, leading to uncertainty about what services would be regulated.[108] The AER concluded that the definition did not provide a 'bright-line threshold'[109] and that services should continue to be assessed case by case under the statutory definition in the NER.[110]

The service classification guideline provides the framework for identifying whether a service is a distribution service and, if so, how it should be classified for regulatory purposes.[111] It improves clarity, transparency and predictability by applying the NEL (including the form of regulation factors[112] and the NEO), the NER, and best-practice regulation to develop baseline service groupings and classifications.

There are various types of distribution service to which different levels of regulatory oversight apply.

Direct control and negotiated distribution services

If the AER determines that a service is a distribution service, the AER will then classify it as either a direct control service (standard control or alternative control) or a negotiated distribution service.[113]

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105 National Electricity Rules, ch 10.

106 AEMC, *Contestability of energy services – Consultation paper*, Australian Government, 15 December 2016.

107 AEMC, *Contestability of energy services: Final determination*, Australian Government, 12 December 2017.

108 AEMC, *National Electricity Amendment (Contestability of energy services) Rule 2017: Rule determination*, Australian Government, 12 December 2017.

109 A **bright-line rule** (or **bright-line test**) is a clearly defined rule or standard, composed of objective factors, which leaves little or no room for varying interpretation.

110 AER, *Draft explanatory statement: Electricity distribution service classification guideline*, Australian Government, June 2018.

111 AER, *Service classification guideline*, Australian Government, August 2022.

112 The form of regulation factors is set out in section 2F of the NEL.

113 NER Cl. 6.2.1

The AER does not actively classify services unless they are proposed in a revenue determination. The AER also reviews and approves each distribution NSP's negotiating framework, which will apply to any negotiated distribution services.

In 2018, the AER developed a list of baseline service groupings, which represent the core services provided by a typical distribution NSP.[114] These groupings gave practical effect to the broad definition of distribution service, promoted consistency across distribution NSPs and allowed the AER to focus on incremental classification changes in each framework and approach process.

Direct control services were separated into the following groupings, although it is not intended to indicate that distribution NSPs can provide all activities that might meet these definitions (for example, metering contestability was in place at the time that these groupings were developed, so distribution NSPs would not be expected to undertake type 1-4 metering):

- **Common distribution services**: Effectively a single service, this grouping relates to the conveyance or flow of electricity through the network for consumers (and includes activities that relate to maintaining network integrity). The common distribution service is the bundle of distribution activities used by customers, relating to their use of the shared network.
- **Network ancillary services**: These services are best described as those offered to customers and/or third parties that are related to common distribution services. While they are related, these services do not form part of the bundled common distribution service because not all customers request or require these services.
- **Metering services**: This grouping of services relates to the measurement of electricity supplied to and from customers through the distribution system (excluding meters on the network's side).
- **Connection services:** This grouping includes activities relating to the electrical or physical connection of a customer to the distribution network.
- **Public lighting services:** This grouping relates to lighting services provided by means of or in connection with a distribution NSP's distribution system.

The baseline service groupings also describe negotiated distribution services. This is a classification for services that have prices set by the parties to the negotiation. Beyond the initial classification decision,[115] the AER approves each distribution NSP's negotiating framework and may be involved in resolving disputes between distribution NSPs and customers. There are relatively few negotiated services in the NEM.[116]

Unregulated distribution services

In 2016, the AER defined an 'unregulated distribution service' as a distribution service that has not been classified as direct control or negotiated services including through an existing grouping[117] In some circumstances the AER may identify that a service is an 'unregulated distribution service' or a 'non-distribution service' if we consider that this will provide greater clarity. This is done on a case-by-case basis or if requested by stakeholders.[118] The concept of an 'unregulated distribution service' is not present in the NER, as the AER's prescribed role is to determine services that are to be

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114 AER, *Explanatory statement: Distribution Service Classification Guideline*, Australian Government, 28 September 2018.

115 Under NER, cl. 6.2.1(a).

116 AER, *Distribution Service Classification Guideline*, Australian Government, August 2022.

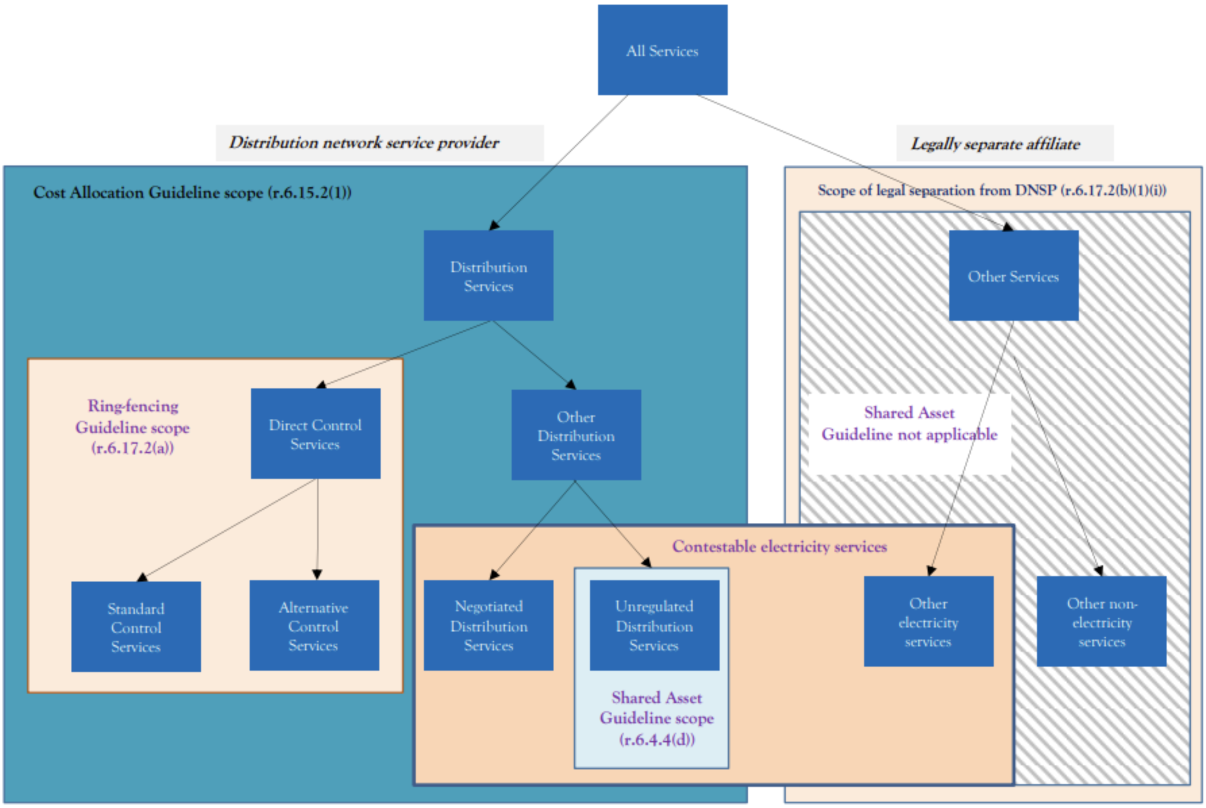
117 AER, *Distribution Service Classification Guideline*, Australian Government, August 2022.

118 IBID.

classified.[119] However, the AER has a role in regulation of these services via boundary regulation, such as the ring-fencing, cost allocation and shared asset guidelines.

Negotiated distribution services and unregulated distribution services are considered 'contestable electricity services' for the purpose of ring-fencing (see Figure 4). Distribution NSPs may provide these services, so long as they are 'functionally separate' from the provision of the distribution NSP's direct control services, including complying with obligations on non-discrimination, sharing and co-locating staff, information and co-branding of advertising materials.[120]

Figure 4: Regulatory treatment of distribution services[121]



Other services

Other services are defined as "services other than transmission services or distribution services" in the Ring-fencing guideline (electricity distribution).[122] The current ring-fencing framework prohibits distribution NSPs from offering other services, including other electricity services and other non-electricity services, to prevent them from using their monopoly position to undermine competition in contestable markets or subsidising the provision of other services (see Figure 4). However, distribution NSPs are permitted to:

- establish a legally separate affiliated entity to offer these services, subject to meeting a range of ring-fencing obligations

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119 AER, Service classification and asset exemption guidelines: Issues paper, Australian Government, February 2018.

120 AER, Ring-fencing Guideline: Fact Sheet, Australian Government, 30 November 2016.

121 AER, Ring-fencing Guideline: Explanatory statement, Australian Government, 30 November 2016.

122 AER, Ring-fencing guideline: Electricity distribution, version 4, Australian Government, 27 February 2025.

- apply for a waiver to ring-fencing obligations, either via the ring-fencing or sandbox pathways e.g. to conduct a trial.

4.1.2 Changes in distribution service classification

Since the AEMC last considered the definition of a distribution service, the mix of services provided by distribution NSPs has changed. Some services have moved out of regulated classification as reforms opened them to competition, most notably metering, while other services have been described and clarified more explicitly. Some services reflect a genuine change in the role of distribution networks in a two-way system, including export and dynamic services, stand-alone power systems, and other coordination-oriented functions associated with CER integration.

Unclassified services previously regulated

The AEMC's 2015 metering contestability reform opened metering services to competition and required the AER to publish a distribution ring-fencing guideline.[123] Metering services include maintenance, reading, data services, and the recovery of capex related to metering assets. As a result of the AEMC's reform, metering was no longer considered a distribution service (except for Victoria where distribution NSPs are still the monopoly providers of most metering services to small customers).[124]

Clarification of existing services

Prior to the introduction of the Ring-fencing guideline (electricity distribution) in 2016, the AER's established practice had not been to seek an exhaustive listing of a distribution NSP's unregulated distribution services in the service classification decision. [125] Following the introduction of the Ring-fencing guideline (electricity distribution), it became increasingly important for distribution NSPs and other stakeholders that the AER's service classification decisions reflect a fuller listing of distribution services, including unregulated distribution services. This helped to provide clarity on which ring-fencing obligations would apply to these services.

In 2017, the AER recognised that distribution NSPs were already providing a range of services that were (or were likely to become) unregulated distribution services and therefore would be subject to functional separation ring-fencing requirements. The AER made several clarifications to service classification to make it clear that these services are direct control services.

- Non-standard connections were historically unregulated but moved into the alternative control service classification to allow distribution NSPs to continue providing the service.[126]
- SAPN provided many negotiated services compared to other distribution NSPs that were moved into the alternative control service classification in the subsequent regulatory determination to avoid ring-fencing complications.[127]
- Distribution asset rental was previously classified as unregulated, but a new aspect of the common distribution service was introduced to allow distribution NSPs to facilitate this service from within the regulated business. [128]

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123 AEMC, *Expanding competition in metering and related services*, Australian Government, 26 November 2015.

124 AER, *Attachment 15: Metering services – Draft decision – Jemena distribution determination 2026–31*, Australian Government, 30 September 2025.

125 AER, *Electricity Distribution Service Classification Guideline*, September 2018.

126 AER, *Ring-fencing waiver applications: Final decision*, Australian Government, 18 December 2017.

127 AER, *Ring-fencing waiver applications: Final decision*, Australian Government, 18 December 2017.

128 AER, *Ring-fencing Guideline: Explanatory statement*, Australian Government, 30 November 2016.

Classification of additional services

Since 2018, when the AER developed baseline service groupings, distribution NSPs have begun to provide a wider range of services associated with a two-way system, including:

- Classifying export and dynamic services as standard control services[129]
- Integrating distribution NSP-led stand-alone power systems (SAPS) into the standard control service[130]
- Other coordination-oriented functions linked to integration of CER.[131]

These new services are characterised in the present phase in the history of the NEM that was defined in Section 2.5 – Phase 5: A transitioning system – and will be explored in more detail in the next section.

4.1.3 The ongoing evolution of distribution services

As Australia transitions from a centralised, fossil fuel-based system to a decentralised, renewables-based system, the role of distribution NSPs is changing as they need to optimise their networks to account for two-way energy flows.

Distribution NSPs are responsible for various interfaces through which different electricity service providers interact with the distribution system. To facilitate this, distribution NSPs undertake 'coordination functions' so that access, operation and investment occur safely, efficiently and on consistent terms. The growing importance of these coordination functions is reflected in the AER 2020–25 Strategic Plan under which the AER will 'deliver efficient regulation of monopoly infrastructure while incentivising networks to become platforms for energy services'. We suggest that there are several types of coordination functions.

- Access services
- Orchestration services
- Services at the boundary of the network

Access services

Services that distribution NSPs have historically offered to facilitate access to the network (such as information and connection services) have become increasingly relevant to facilitate new and emerging contestable electricity services. Participants in a two-way system require more access services from distribution NSPs than the traditional model assumed, including granular network-capacity data,[132] timely and transparent connection processes, clearer access conditions, and better visibility of local constraints.[133] Speed and certainty of access are also becoming more important, particularly for DER connections and EV charging infrastructure, where delays or unclear access terms can affect investment timing and whether a project is commercially viable.

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129 AER, *Final Framework and Approach: Victorian electricity distribution determinations 2026–31*, Australian Government, 31 July 2024.

130 AER, *Explanatory statement: Updating instruments for regulated stand-alone power systems*, Australian Government, May 2022.

131 AER, *Final Framework and Approach: Victorian electricity distribution determinations 2026–31*, Australian Government, 31 July 2024.

132 EVC, *EVC response to ESB-AER: Benefits of increased visibility of networks consultation paper*, Electric Vehicle Council, 24 August 2023.

133 Clean Energy Council, *Submission to the Australian Energy Market Commission's Integrated Distribution System Planning rule change*, Clean Energy Council, 24 July 2025.

System Visibility

As the monopoly owners of network infrastructure and associated data, the provision of data access to the market is key in enabling competitive market outcomes and encouraging greater consideration of non-network solutions.[134]

The NER currently requires distribution NSPs to release some data for public access. This includes:

- Annual Information Orders that are submitted to, and subsequently published by, the AER.[135]
- Distribution Annual Planning Reports published by distribution NSPs.

Data requests are received from a large range of stakeholders including residential, small business customers, commercial customers, government, community groups, universities, consultants, councils, developers and renewable generators.[136]

Several distribution NSPs host online data portals that allow their network data to be visualised spatially. The level of detail available can still depend on things like smart meter coverage and the minimum functional specification of the meters in place. Interested parties may also submit requests to distribution NSPs for data that isn't publicly available,[137] however:

- distribution NSPs may choose not to provide information that they consider to be difficult to produce, or that would violate customer privacy.[138]
- some information, such as whether a proposed new connection is able to be made, is available to external parties only after submitting a connection application and paying associated fees to cover assessment costs by distribution NSPs.[139]

However, some stakeholders have advocated for improved access to more granular and transparent data. For example, the Clean Energy Council supported AEMC's proposal for distribution NSPs to publish detailed hosting capacity metrics, utilisation, export capacity, and low voltage (LV) network insights, with a roadmap for data improvements. The Clean Energy Council also advocated for standardised data formats, timely updates, and open access where possible and noted that improving hosting capacity visibility is critical to enable CER uptake and Virtual Power Plant services.[140]

In July 2023, the AER published the Phase 1 consultation paper "Benefits of increased visibility of networks", which was authored by the Energy Security Board (ESB).[141] The intention of this project was to define the range of use cases for network data and the associated required datasets.

As part of the 2024–29 NSW distribution NSP resets, NSW distribution NSPs proposed "provision of standardised data sets and/or data that is provided to a distributor in accordance with obligations under the Rules" to be incorporated into the common distribution service. Essential Energy highlighted

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134 Clean Energy Council, *Submission to the Australian Energy Market Commission's IDSP - Directions Paper*, Clean Energy Council, November 2025.

135 AER, *Annual Information Orders 2024-25 to 2027-28*, Australian Government, 5 April 2024.

136 CPU, *Submission to AER ESB Network Visibility Paper*, CitiPower, Powercor and United Energy, 1 September 2023.

137 AER, *Low-voltage Network Visibility: Summary of neighbourhood battery trials*, Australian Government, 11 October 2024.

138 IBID.

139 IBID.

140 CEC, *Submission to the AEMC on its Integrated Distribution System Planning - Directions Paper*, Clean Energy Council, November 2025.

141 Energy Security Board, *Benefits of increased visibility of networks: Consultation paper*, Australian Government, July 2023.

the network visibility reforms underway, which may result in expanded obligations on networks as data sharing frameworks are established and refined.[142]

As part of the 2026–31 Victorian distribution NSP reset decisions, Victorian distribution NSPs proposed a new framework for provision of data to customers or other stakeholders. Under this proposal the provision of basic network data, such as visibility maps and data portals, would be incorporated within the common distribution service, and classified as direct control, standard control services.[143]

The Victorian businesses submitted that their proposed framework would provide for more equitable cost allocation and is consistent with the objectives of the AER's Network Visibility project. This was reflected in a final classification decision to include "provision of basic electricity distribution network data, including data that is provided in accordance with legislative obligations, standardised or automated data sets".

This update to the common distribution service reflects the AER's vision for a future energy system where distribution NSPs publicly provide all data that they have that is useful to their stakeholders, except where data cannot be published for security, commercial or personal privacy reasons.[144]

This is expected to expand further as part of the AEMC's ongoing rule change process to enhance distribution network planning and reporting.[145] The proposed rule change will:

- require distribution NSPs to regularly produce and publish an expanded suite of network data; and
- establish a consistent, longer-term strategic planning framework to improve predictability of augmentation plans and support more effective joint planning.

Connections

Historically, many network-facing services have been classified as alternative control services, as they are often required by a subset of identifiable users and involve costs that can be directly attributed to those users. The AER's Electricity Distribution Service Classification Guideline and Connection Charge Guideline both reflect this logic: where a connection or related access service is only required by some customers, some of the time, and the relevant distribution NSP is the unavoidable provider, user-pays regulation through alternative control services has often been regarded as appropriate.

In recent years, stakeholders have raised concerns that the connections process is complex and uncertain. In response to the AEMC's Enhancing Investment Certainty rule change request, the Clean Energy Council states that connecting a generator or storage asset to the NEM is onerous and time consuming, with a high bar set in terms of technical capabilities, exacerbated by complex modelling requirements. They note that monopoly networks have an incentive to load uncertainties and associated costs onto connecting parties and that these material uncertainties are a major headwind to attracting international capital to invest in the NEM.[146]

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142 Essential Energy, *6.01 Classification of Services*, Essential Energy, November 2023.

143 CitiPower, Powercor, United Energy, *Proposed framework and approach 2026–31*, October 2023, p.6; Jemena, Framework and approach letter and proposal, October 2023, p.22; AusNet, *Request to replace framework and approach*, October 2023, p.15.

144 AER, *AER submission to AEMC Integrated distribution system planning directions paper*, Australian Government, 17 November 2025.

145 AEMC, Enhancing distribution network planning & reporting, April 2026.

146 CEC, *Submission to AEMC's Enhancing Investment Certain rule change process*, October 2023.

Access to infrastructure & land

In some instances, distribution NSPs facilitate access to infrastructure, such as office space, poles and ducts, or land, such as land around zone substations. Distribution asset rental has historically been treated as an unclassified distribution service,[147] which means that the AER considers the service does not require revenue regulation.[148] By nature of not being classified, the AER receives minimal information on how distribution NSPs are undertaking this service, such as through shared asset reporting. Some stakeholders have raised concerns with the AER about the ability for third parties to access distribution NSP-owned infrastructure or land that is required to deliver a product or service. For example, in consulting on CitiPower, Powercor and United Energy's (CPU's) waiver application stakeholders noted high fees and restrictive Facilities Access Agreement terms where being faced by contestable Charge Point Operators accessing distribution poles[149]. In 2026, The AER proposed to classify pole leasing (a subset of distribution asset rental) as a negotiated service in the draft Victorian revenue determinations.[150] This was proposed to support negotiation of access to Victorian distribution NSPs' kerbside poles for that purpose on terms that are fair, reasonable and cost reflective in response to stakeholder concerns with respect to connection services.

Orchestration services

In light of the increasing uptake of distributed energy resources and the range of services these technologies are capable of providing, distribution system operations are beginning to offer a wider range of services to a wider range of participants that aim to optimise and coordinate this rollout.

Where effectively managed and seamlessly integrated, CER & DER can help with more reliable, secure and cheaper energy. This reduces the need for large-scale grid investment, benefits all customers and rewards CER owners for the value their CER provides to the system. However, the use of coordinated CER & DER to provide network services such as managing network congestion or provision of other system services has been relatively limited to date. DER-based options to meet distribution network requirements are still predominantly at the trial phase, often with financial support from ARENA or other government entities.

Dynamic signals (Dynamic Operating Envelopes (DOEs), flexible export limits (FELs), and dynamic connections) are emerging as an increasingly common tool used as the basis for varying the import and export limits for a customer over time and location. The limits are varied based on the available capacity of the local network or power system as a whole.[151] DOEs can help capture CER & DER value by enabling higher levels of energy exports from customers' solar and battery systems when there is more hosting capacity on the local network and more equitable treatment of customers at times when access is limited.[152] The AER export limit guidance note provides a framework for the application of export-side DOEs.[153]

To date, the AER has taken the position that distribution NSPs are best placed to determine when and if FELs are necessary for efficiently managing network congestion to improve network hosting

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147 AER, *Ring-fencing guideline: Electricity distribution,* Australian Government, 30 November 2016.

148 AER, *Distribution Service Classification Guideline*, Australian Government, August 2022.

149 Nexa Advisory, *Submission to CPU ring-fencing waiver for EV charging infrastructure*, June 2025.

150 AER, *Overview: Draft decision – Jemena distribution determination 2026–31*, Australian Government, 30 September 2025.

151 DEIP DOE Working Group, *Allocation Principles Workshop Summary*, Australian Renewable Energy Agency, July 2021.

152 DCCEEW CER Taskforce, *Distribution system and market operations: Consultation paper*, Australian Government, July 2025.

153 IBID.

capacity.[154] In publishing an export limit guidance note, the AER set out that it intends to monitor distribution NSP adherence to the guidance note to determine whether it has been effective in addressing identified problems and promoting the intended policy outcomes. Preliminary assessment of 2026-31 revenue proposals indicates that Victorian distribution NSPs have provided some information on their hosting capacity analysis[155], but did not provide evidence of meaningful industry engagement on FELs and were lacking transparency in some areas.[156]

Distribution NSPs have acknowledged that they are required to facilitate CER export and that certain costs associated with CER integration will be recoverable.[157] Furthermore, distribution NSPs have an apparent incentive to use mechanisms like FELs, DOEs and dynamic network prices to improve orchestration of CER as this presents opportunities for savings in operational and capital expenditure. These savings are incentivised under the EBSS and CESS incentive schemes, as well as the export service incentive scheme, which enables distribution NSPs to set CER export service performance targets based on the priorities and preferences of distribution NSPs' customers.[158] Distribution NSPs are likely to further explore the facilitation of CER as they adopt roles as the Distribution System Operator.

Distribution NSPs as Distributed System Operators

The following case study explores how CitiPower considers network tariffs performing a role in supporting non-tariff demand management initiatives by providing discounted network tariff rates in return for handing the distribution NSP some form of control, for instance load control of hot water, limiting exports or imports, or other types of flexible connection arrangements.[159]

CitiPower flexible connection arrangements

Flexible connection is import and/or export management actioned through connection agreements such as an agreement to be connected to and potentially controlled by distribution NSP systems or an agreement to limit imports and/or exports under certain network conditions.[160]

The reward for a flexible connection is a lower connection charge and a lower contribution to residual network costs in the network tariff. Flexible connections also remove the need for network tariffs to signal short-term local capacity constraints through network tariff charges for behaviour which exacerbates the constraint. Furthermore, flexible connections located in areas where network support is required will have the opportunity to be rewarded through network support payments outside network tariffs.

CitiPower has already introduced flexible connections for high voltage storage and generation connect to their distribution energy resource management system. This system allows the distribution NSP to secure a dynamic operating envelope by discontinuing, interrupting or limiting the quantity of electricity imported from or exported to the distribution system.

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154 AER, *Flexible export limits: Final response and proposed actions,* Australian Government, July 2023.

155 AusNet Services, *Hosting Capacity, Electrification and CER Enablement Methodology*, November 2025; Jemena Electricity Networks (Vic) Ltd. *Consumer Energy Resources – Integration Strategy*, January 2025; United Energy, *Part B: explanatory statement. Revenue and expenditure forecasts*, January 2025.

156 AusNet Services, *Future Networks Panel*, viewed May 2026; Jemena Electricity Networks (Vic) Ltd. *Energy Reference Group Meeting Paper 4*, viewed May 2026; United Energy, *Part B: explanatory statement. Revenue and expenditure forecasts*, January 2025.

157 AER, *Export limit guidance note*, Australian Government, 23 October 2024.

158 DCCEEW, *Redefining roles and responsibilities for power system and market operations in a high CER future*, Australian Government, July 2025.

159 Citipower, *Revised proposal 2026-31 Tariff structure statement Explanatory statement*, December 2025.

160 IBID.

In their 2026-31 regulatory proposal, Citipower proposed flexible connections for low voltage connected generation and storage, such as community batteries located downstream of a distribution transformer.

Citipower's flexible connection program demonstrates how distribution NSPs can undertake orchestration functions through controlling customer assets to manage demand while returning a benefit to the customer.

Although many orchestration services have been offered as part of the common distribution services, this is not necessarily always the case. In April 2024, the AER granted SA Power Network (SAPN) a ring-fencing waiver to undertake their Market Active Solar Trial. This trial involved dispatching curtailment signals to a customer's solar inverter. Although two models of deployment were considered direct control services because the distribution NSP is only dispatching their own signal, a third model involved using SAPN's system to provide a retailer's control signal to a customer solar inverter. Although SAPN is undertaking the trial to determine the most effective model of deployment, this indicates that distribution NSPs may need to undertake orchestration in a way that doesn't currently fit into the groupings of services that a distribution NSP is able to offer.

Services at the boundary of the network

New business models and technologies such as electric vehicle charging infrastructure, community scale batteries and flexibility services are challenging the traditional definition of a distribution service, making it difficult to distinguish between regulated monopoly functions and contestable market activities.

In the past 2-3 years, the AER has received a range of ring-fencing and sandbox waiver applications to allow distribution NSPs to offer 'other electricity services' that often relate to DER and CER:

- Selling excess capacity on network-owned battery energy storage systems
- Installation, ownership and maintenance of kerbside EV charging infrastructure
- Installation and ownership of domestic solar PV.

The following case study explores how the service of owning, maintaining and providing access to electric vehicle charging infrastructure has been proposed by networks in different contexts with uncertainty around whether or not this meets the definition of a distribution service.

Electric vehicle charging infrastructure

In 2025, CPU applied for a ring-fencing waiver to run an electric vehicle charging infrastructure trial. In their application CPU stated that they considered that electric vehicle charging infrastructure services may be provided in connection with the distribution system and may accordingly come within the NER definition of "distribution services" but nevertheless sought a waiver from clause 3.1.[161]

In SAPN's 2025-30 regulatory determination, the AER stated that it is not clear whether electric vehicle charging infrastructure of last resort would be a distribution service. However, the AER noted that we did not need to reach a conclusion on this question as we did not find a material change in circumstances to justify moving away from SAPN's approved Framework and Approach for the 2025–30 regulatory period.[162]

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161 CPU, *Supplementary ring-fencing waiver application: EVCI*, CitiPower, Powercor and United Energy, April 2025.

162 AER, *Attachment 13: Classification of services – Final decision – SA Power Networks distribution determination 2025–30,* Australian Government, April 2025.

In 2026, the AEMC received three rule change requests relating to service classification for electric vehicle charging infrastructure. The ENA rule change request would specify that distribution NSPs are able, but not required, to offer public electric vehicle charging infrastructure as a direct control service. The AER would then determine whether the service is an alternative control service or standard control service.

The DCCEEW rule change request relates to a $40 million grant program to facilitate the rollout of EV charging infrastructure. The proposed grant program would require Distribution Network Service Providers (DNSPs) to perform certain activities and, in limited circumstances, would allow DNSPs to install EV charging infrastructure in targeted locations. The proposal is time-limited and restricted to assets under the grant program.

The Nexa Advisory rule change request proposes changes to strengthen the ring-fencing framework that applies to distribution services by moving it from an AER guideline to the National Electricity Rules (NER) and adding additional protections.

Distribution NSPs as Distributed System Operators

In December 2025, Energy Ministers accepted the recommendation of the CER Taskforce that distribution NSPs be formally assigned the role of Distributed System Operator (DSO). This role recognises the distribution networks as platforms for energy services rather than simply asset owners and operators.

As DSOs, distribution NSPs will be required to deliver a range of coordination functions, outside their traditional responsibilities in owning and operating the network. In practice, distribution NSPs are already performing elements of this role through the coordination functions explored above such as orchestrating DER and facilitating access to data and infrastructure. The CER Taskforce's DSO report notes that the AER has already approved expenditure for distribution NSPs to undertake "DSO-like activities" and invest in DSO capabilities.[163] The CER Taskforce has noted that consideration of these roles will ensure there are no gaps in the activities being undertaken to effectively integrate CER into the power system and market:

- **Active system management:** Actively manage network assets, CER and flexible loads to achieve safe, reliable and efficient operation of the distribution system in a two-way power flow environment for example, assessing hosting capacity limits, and managing and publishing dynamic operating envelopes.
- **Enabling CER flexibility:** Involves employing distribution level tools, mechanisms, and market interfaces to value, incentivise, procure, and coordinate energy and flexibility services from CER.
- **Transmission–distribution coordination:** active coordination between the system operators and network operators to enable operational visibility and data exchange required for operations, and for system security and reliability.
- **Integrated distribution planning:** perform long-term distribution system planning, in consultation with the system operator (AEMO in the NEM) and relevant transmission network, as an integral part of advanced whole of system planning.

The CER Taskforce's report notes that distribution NSPs are already undertaking many DSO-type functions, which has been facilitated by changes within the existing regulatory framework. For example:

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163 DCCEEW, *Redefining roles and responsibilities for power system and market operations in a high CER future*, Australian Government, July 2025.

- the emergence of dynamic operating envelopes, supported by the AER's Export Limit Guidance Note on funding flexible export limits.
- removal of the prohibition on export tariffs under the AEMC's *Access, pricing and incentives arrangements for distributed energy resources* rule change, allowing distribution NSPs to propose introducing two-way pricing to match the two-way flows on their networks.
- publication of the AER's DER Integration and expenditure guidance note, which supported distribution NSP expenditure requests for DSO-like activities and capabilities.

However, the CER Taskforce considers that the role of DSO needs to be formalised to establish DSO expectations, rights and obligations as well as establish appropriate incentives to encourage distribution NSPs to maximise DSO outcomes and determine reporting requirements.

The assignment of the DSO function to distribution NSPs has raised questions about how this function should be governed and includes whether the existing regulatory framework, designed primarily to govern the network's expenditure and investment decisions, provide adequate tools for governing the quality, competitive neutrality and effectiveness of distribution NSP performance.

While distribution NSPs have been able to provide some DSO-like services through the common distribution services, some stakeholders have raised concerns of the distribution NSPs being able to provide these services (or other coordination services) in a competitively neutral manner. Furthermore, DSO roles have focused to date on activities and capabilities related to new and emerging technologies, but have not focused as much on other, traditional coordination functions like access and connections.

4.2 Transmission

There are significant differences between how transmission services are defined in the NEM compared to how distribution services are defined and classified. Consequently, we consider that detailed consideration of service classification be focused on distribution.

The NER defines transmission services as 'services provided by means of, or in connection with, a transmission system' and defines three categories of transmission services – prescribed, negotiated and non-regulated transmission services. Prescribed transmission services cover services that benefit or are required by all consumers including use of the core transmission network not exceeding performance standards and transmission planning functions. Negotiated transmission services cover those that can typically be attributed to a single large party such as connection services for a large-scale generation project or exceeding minimum performance standards. Non-regulated services cover anything else including fully contestable transmission connection works. As these are defined in the NER, the classification of services does not occur during revenue reset.

As a result, transmission service classification has been quite consistent across transmission NSPs, notwithstanding differences in individual transmission NSP interpretation and delivery of services.

Further, there appears to be generally no major stakeholder concerns raised regarding the definition or breadth of transmission services. A major contributing factor for this is because the fundamental role and responsibilities of transmission NSPs in the NEM has remained largely consistent over time. This contrasts to the more substantial changes distribution NSPs have faced in response to both the introduction of competition in retail and metering as well as the need to effectively manage growing levels of distributed energy resources.

The general acceptance of the definition or breadth of transmission services is also likely aided by the independent and transparent process to amend service definition and classification via AEMC rule changes. This process also means that stakeholders may have greater confidence that outcomes are more directly aligned with NEM-wide policy outcomes.

Treatment of dual function assets

Dual function assets are network assets that perform both transmission and distribution functions, such as sub-transmission lines and associated connections. Services provided by these assets can therefore fall within both transmission and distribution regulatory frameworks.[164]

Under the National Electricity Rules (NER), Clause 6.24.2(c) establishes a reciprocal service classification approach. Where a distribution NSP provides a negotiated transmission service using a dual function asset, that service is also deemed to be a negotiated distribution service.[165]

In practice, this means the AER does not determine the distribution classification of these services through the usual reset process. Instead, the classification flows directly from the transmission service classification, which can have important regulatory consequences. One key implication arises under the AER's Ring-fencing Guideline (electricity distribution), which treats negotiated distribution services as contestable services subject to functional separation requirements. As a result, services delivered via dual function assets may be required to comply with distribution ring-fencing obligations, even where they are fundamentally transmission in nature.[166]

This issue is becoming more relevant over time. Potential growth in connection-intensive loads, such as data centres, is increasing demand for bespoke network solutions, including sub-transmission and dual function assets. At the same time, differences in how negotiated services are treated across transmission and distribution frameworks mean that similar services may be subject to different regulatory obligations depending on their classification. More broadly, this raises questions about whether the current classification approach consistently aligns regulatory requirements with the underlying characteristics of the service.

A recent case involving a distribution network's treatment of services associated with a sub-transmission substation illustrates these issues in practice. In that case, services classified as negotiated transmission services are also deemed to be negotiated distribution services under Clause 6.24.2(c), and are therefore treated as contestable services under the distribution ring-fencing guideline. This results in services that are transmission in nature being subject to distribution ring-fencing obligations, requiring either functional separation or a waiver. The case highlights how the interaction of classification rules across frameworks can lead to outcomes that may not fully align with the intent of either framework when considered in isolation.

164 AEMC, *National Electricity Rules*, Australian Government, April 2026.

165 AEMC, *National Electricity Rules Chapter 6*, Australian Government, April 2026.

166 AER, *Ring-fencing guideline (electricity distribution) 2022*, 2023.

5 How the future NEM may look

Australia's electricity system is undergoing massive transformation through increased CER and DER adoption, accelerating electrification and significant shifts in generation and consumption patterns. Electrification of transport, heating and industrial processes is expanding the share of economic activity that depends on the electricity network, increasing its structural significance relative to other energy sources.

We have explored different ways in which the future electricity system might unfold to explore where this transformation might challenge the effectiveness of the regulatory framework. The existing framework has been reasonably effective, but considering the significance of the transformation it is appropriate to proactively review the framework to ensure it remains fit for purpose.

We have developed alternative futures that represent potential visions of the future of the NEM. These visions are intended to represent what the NEM may look like in 2045–2050 and are designed to provide a useful framework for considering the future of electricity network regulation. They are not (and are not intended to be) exhaustive – there are other potential visions of the future or 'future worlds' that could be developed. These scenarios are stable future states, rather than transitional stages or an untenable future where the system or framework would break down.

The development and description of the alternative futures are a fundamental step in identifying potential issues in the current regulatory framework. This work is ongoing and we expect to expand on this in future papers and submissions.

5.1 Development of scenarios

We have reviewed existing industry reports and documents to guide early thinking on drivers and potential directions of change. We sought reports that provided bold visions of how people interact with the energy system in the future and a more formal structure for thinking about what factors could drive the evolution of the energy system. These reports included reports such as the *Digital Energy Futures* by Monash[167] and *Navigating to Australia's Future Grid* by Energy Catalyst.[168]

These helped to identify drivers of change that may affect how the NEM develops into the future. To narrow this list to a manageable number to inform design of alternative futures, these were consolidated within common themes and grouped into two broad categories:

- **Common assumptions:** These drivers of change have informed the design of all the alternative futures because they are either more certain in any future (such as the transition towards renewable generation supported by firming capacity to meet net zero commitments) or would be less informative in testing how the network regulatory framework may be stressed (such as the design of the wholesale market).
- **Differentiating dimensions:** We have designed the alternative futures to test these drivers of change, which remain key sources of uncertainty and which we believe are most informative in uncovering stress points in the current regulatory framework. The futures assume different levels of change on these dimensions to test their potential impact on the electricity system and regulatory framework.

5.2 Common assumptions

All alternative futures share the following assumptions, grouped within 5 key areas of change.

167 Monash University, Digital Energy Futures: Scenarios for Future Living 2030/2050, February 2023.

168 Energy Catalyst, Navigating to Australia's Future Grid, August 2025 (in particular, Report 2 Emerging Trends Driving Grid Transformation).

- **Broader environment**
  - Extreme weather events will be more common and more severe.
  - Supply chain and financing conditions are more exposed to global conditions which could result in increased or more uncertain costs as well as project delays.
  - There will be more opportunities for NSP to procure services rather than building, investing or delivering themselves.
  - It will be more important to build and maintain social licence and a political authorising environment.
- **System operation**
  - Supply-side versus demand-side distinctions will become less relevant as technology and systems allow solutions to come from across the supply chain.
  - There will be more bi-directional and volatile power flows in the system, making the system more computationally complex to model and to operate.
  - Flexibility and balancing services will be more necessary and available, although how they are valued and coordinated will vary.
  - More participants will be actively engaging with and using the system (e.g. those directly seeking to connect to the network, such as generation and storage proponents, as well as those indirectly using the network as a platform to provide value-adding services, such as CER aggregators, VPP operators and home automation services).
- **Generation and storage**
  - The closure of thermal generation and increase in variable renewables with firming generation will continue.
  - Grid-forming technology[169] will become more common as technology continues to develop, providing a latent resource that could potentially be called upon.
  - Grid-scale battery costs will fall and they will become more common in the system.
  - Consumers' installation of CER will continue to grow.
  - The technical capability of new CER installations as well as the combined capability of the CER fleet will continue to improve (e.g. their ability to provide firming capacity, communication ability, data).
  - More network augmentations will be driven by the need to host and integrate generation and storage rather than only to meet load growth.
- **Load and demand**
  - Electrification and new loads result in growing total (i.e. native) electricity demand, although a proportion of this may be met locally by self-consumption and not always required to be met by the grid.
  - More tools and technology (including artificial intelligence) are available to allow automated responses to price signals and other demand management activities.
- **Data and digitalisation**
  - More, more granular and more varied data is available and required for decision-making.
  - Cyber security risks become more critical (including managing legacy architecture).
  - Interoperability and low latency of data become important factors incorporated in product and system design.

[169] Grid-forming and grid-following technology allows inverter-based resources (such as solar and wind) to provide more of the essential system services (such as system strength or system restart capability) that have traditionally only been able to be delivered by thermal or hydro plant.

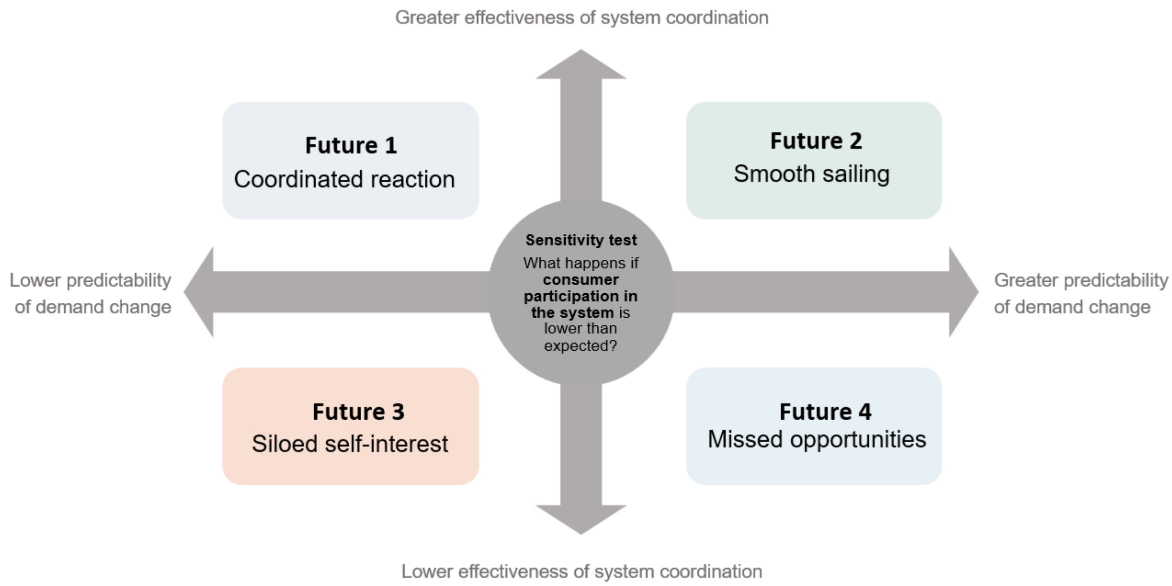
5.3 Differentiating dimensions

We have designed the alternative futures to test the combined impacts of the following dimensions:

1. **Effectiveness of system coordination**, which includes how effectively whole-of-system plans can be made and implemented to optimise across the supply chain, the ability to see and activate capability across the supply chain to effectively plan responses and mitigate risks, and the degree of alignment between government policies and efficient NEM-wide outcomes. This might be driven by effective policies and planning frameworks, as well as the existence of well-operating markets or signals that procure or incentivise necessary services and responses.
2. **Predictability of demand changes**, which refers to how well the nature of changing demand can be adequately predicted and hence planned for. This could be in terms of the quantum of energy, its impact on daily/seasonal load profiles, where in the system the demand occurs or the timing of any demand changes. The change in demand could be driven, for instance, by the electrification of existing loads or through the entry of newer loads such as data centres.
3. **Level and nature of consumer participation in the system**, which includes the degree to which consumers (including residential, commercial and industrial consumers) are willing to use or allow some use of their CER for system optimisation rather than for self-optimisation. The alternative futures in this paper assume some degree of consumer willingness to participate in system optimisation, such as by responding to price signals in network or retail pricing, automating their devices in response to price signals, signing up to Virtual Power Plants or similar aggregation programs, or in some instances just remaining connected to the system despite the availability of cost-competitive self-supply options.

These three factors are not entirely independent. For example, effective system coordination may involve incentivising consumers to participate in the system. Furthermore, the predictability of demand change may be a driving force for undertaking this approach to coordination and participation. However, they represent important drivers of change to help stress-test the regulatory framework for the future, due to their degree of uncertainty and potential impacts. Figure 5 below illustrates how the alternative futures reflect each of these dimensions.

Figure 5: Illustration of alternative futures against differentiating dimensions



5.4 Description of alternative futures

5.4.1 Future 1: Coordinated reaction

Box 4. Position on differentiating dimensions

- Effectiveness of system coordination: High
- Predictability of demand change: Low

In this future, the system leans less on building large assets far in advance and more on staying flexible. Smarter demand management, staged investments and storage assets become critical to allow the system to adjust to unpredictable demand and minimise the risk of locking in major infrastructure too early.

A more flexible and coordinated approach can help address the risk of project delays, cost blowouts from these delays and over-investment. While there may be less redundancy to prevent outages, greater coordination helps the system recover and restore power to communities more quickly when extreme weather events do occur. This is because network and system operators are able to plan and operationalise targeted, potentially modular responses to restore power more quickly.

However, this approach to addressing network needs undermines longer-term decisions for generation, storage and load. While there is good data visibility regarding network congestion and hosting capacity, there is less certainty about how this congestion and capacity may change into the future.

Network and system operators make heavy use of flexibility services which, in turn, encourages retailers and third parties (such as aggregators) to develop niche, responsive products and build a robust portfolio of participating assets. Over time established businesses such as NSPs and gentailers establish close, long-term partnerships with these flexibility providers.

Consumers increasingly help the system respond to change by shifting their usage, using their own energy resources (such as solar, batteries and EVs) differently, or participating in programs (such as demand response or flexibility programs) that help manage demand as a matter of course or during extreme events.

While some consumers are willing to accept a lower level of grid-supplied reliability where they can supplement it via their own CER, this option remains underutilised by network and system operators in planning and operating the network as technology and government policy settings are just beginning to enable behind the meter PV and storage usage during a network outage.

5.4.2 Future 2: Smooth sailing

Box 5. Position on differentiating dimensions

- Effectiveness of system coordination: High
- Predictability of demand change: High

The system is well connected and planned, and demand change is easier to prepare for. Stronger planning coordination, along with better data visibility and access, provides high confidence about where demand is growing and what kind of response will be needed.

Decisions can be made earlier and can rely less on short-term fixes. While flexibility and demand management play an important role, the high level of predictability and coordination results in timely investment and a longer-term vision of meeting demand changes. Retailers and third parties (such as aggregators) develop and offer flexibility services using large portfolios of participating assets and may enter into longer-term (multi-year) contracts to provide these services.

The energy industry is more willing to make longer-term investments in expectation of future network needs, including upsizing the capacity of network investments ahead of demand growth or hosting capacity arriving (i.e., anticipatory investments). This means network congestion and curtailment are largely 'planned away' and occur less frequently. While anticipatory investment aids efficient longer-term outcomes, some businesses attempt to exploit this opportunity to shift risk beyond what is efficient away from themselves and onto consumers.

The high degree of predictability and coordination also allows businesses to plan to minimise the risk of project cost escalations or delays and mitigate their impact should they occur. This environment where a longer-term planning and investment view is taken may also extend to preventing more severe impacts from extreme weather events, including by hardening key infrastructure.

Households and small businesses play a role through shifting demand, using solar, batteries or EVs differently, or taking part in programs that support system coordination. In this future, flexibility is less critical to managing the system but still valuable. It is also easier to use because the system is more coordinated and future needs are clearer, which supports more effective behaviour change and product development.

5.4.3 Future 3: Siloed self-optimised

Box 6. Position on differentiating dimensions

- Effectiveness of system coordination: Low
- Predictability of demand change: Low

The system is harder to manage because change is uneven and hard to predict. Demand growth patterns are uncertain and there is less coordination across the sector. It is not always clear where pressure will appear, how long it will last, or what kind of response is needed.

The lack of coordination reduces options for effectively managing this uncertainty and undermines the value of flexibility by making it harder to utilise. There is less data available to NEM participants to identify where constraints will emerge and what resources are available to provide flexibility services. The limited access to data and lack of coordination mean market participants seek to exploit market power using data they do have.

Responses to system needs and network planning are fragmented, resulting in solutions that do not effectively balance different system objectives and options – for example, the need to address wholesale versus network constraints or whether solutions are most efficiently provided by transmission- or distribution-level resources.

While flexibility services are important for the system, the lack of coordination means they remain underutilised in system operation and planning. Consequently, flexibility services are less commercially viable, and retailers and third parties (such as aggregators) are unwilling to build large portfolios of participating assets. This leads to the use of more short-term fixes and poorer timing of investments, exposing the system to a greater risk of project cost escalations and delays. It also leads to concerns of market power being exercised by the relatively fewer providers of non-network options and flexibility services.

The system is exposed to greater risk if demand growth is substantially greater, in a different location or earlier than expected – either from large point loads (such as data centres) emerging or from more widespread load growth (such as from electrification). Similarly, less efficient planning increases the risk of network overbuild and, therefore, of assets becoming underused or obsolete over time.

Overall, the system is more expensive and, in response, consumers' willingness to pay for grid reliability reduces, with those who can increasingly managing their own reliability through solar, batteries, EVs or other resources. In the extreme, this leads to grid defection where some consumers with significant CER cease to rely on the grid because they do not trust it to meet their needs or they see energy independence as more cost-effective. This is exacerbated by extreme weather events and other outages, which may make self-supply more salient and provide opportunities for consumers to 'test' energy independence.

5.4.4 Future 4: Missed opportunities

Box 7. Position on differentiating dimensions

- Effectiveness of system coordination: Low
- Predictability of demand change: High

Demand growth is more predictable and manageable but planning across the system is still fragmented. The system has a clearer sense of where change is happening but is unable to respond in a well-coordinated way. This risks higher costs, missed opportunities and more siloed decisions, even when the direction of change is relatively clear.

While the system can prepare for demand growth more easily, the benefits of holistic planning and operation are lost – for example, missed anticipatory investments necessitate avoidable upgrades in another 5–10 years, or opportunities to address transmission-level network constraints via a mixture of distribution-level solutions (or vice-versa) are lost because a lack of coordination has prevented non-network solutions from addressing network constraints through solutions like flexibility services.

The risk of network overbuild and asset underutilisation or obsolescence still exists but is lessened by the more predictable nature of demand changes. Network utilisation metrics may appear positive, but the system as a whole may not be efficient due to less coordinated planning and operation.

Flexibility services are valued but their full potential to coordinate and value stack is not realised because planning remains fragmented and responses are not well aligned. With their potential value undermined, these services are less commercially viable, and retailers and third parties (such as aggregators) are discouraged from building large portfolios to provide them.

Market participants have less access to data to identify where constraints will emerge and what resources are available to provide flexibility services. While the predictability of demand change helps mitigate the downside risk of this, the scarcity of available data and coordination mean some participants seek to exploit market power using what data they do have.

Reliability expectations in this future stay closer to today's standards. The system continues to rely on more familiar approaches to planning and delivering reliability service standards, and consumers are more likely to focus on self-optimisation than broader system outcomes. Households and small businesses still use solar, batteries or EVs, but mainly to manage their own bills, reliability or energy use rather than to support the wider system.

6 What and how we might want to regulate in the future

The NEM's incentive-based framework continues to provide an important basis for constraining monopoly power, supporting investment and promoting efficiency over time. However, it was developed primarily for a system in which NSPs delivered a more stable and conventional set of monopoly services. As the energy system changes, the challenge is increasingly focused on whether the framework remains well suited to the broader range of new services, risks and decisions that future regulation may need to address.[170]

As part of looking at the scenarios that the future regulation may need to address, we will consider the overarching questions:

- What would drive/need to happen for this scenario to come to pass?
- What do we think the desirability and likelihood of this scenario is?
- Does the existing framework enable this scenario to occur (and should it)?

The analysis of alternative futures suggests that three uncertainties are likely to be particularly important in testing the resilience of the current framework. The first is the effectiveness of system coordination – how well planning, operational decisions, incentives and governance arrangements align across transmission, distribution, generation, storage, retailers, aggregators and governments. The second is the predictability of demand change – how well its scale, timing, location and load shape can be anticipated and planned for. The third is the level and nature of consumer participation, including the extent to which consumers are willing to respond to network and market signals or allow their resources to be used to support system optimisation, or instead prioritise self-optimisation and energy independence.

However, it is likely that the regulatory framework will need to respond to some changes. Across all futures, the system is expected to become more electrified, more decentralised, more digital and more exposed to climate, cyber and supply-chain risk. CER capability is expected to continue growing, more network needs are likely to be driven by generation and storage as well as load, and there are likely to be more opportunities for NSP to procure services rather than building and owning assets directly. These common assumptions raise questions about whether the regulatory framework can continue to direct NSPs toward efficient outcomes in a system that is more dynamic, more uncertain and more dependent on coordination than in the past.

The potential changes place pressure on an incentive framework that is strongest at assessing and remunerating conventional capex and opex through revealed costs over time, but less settled in its treatment of visibility services, flexibility procurement, operational coordination and other functions that may be essential to an efficient, highly distributed system. The issue is thus not only what new functions may need to be regulated, but whether the current framework provides the right regulatory levers or incentives for distribution NSPs to prefer efficient network and non-network responses, pursue innovative solutions in reliability and electricity distribution, and remain accountable to consumers as their role expands.[171]

The current incentive framework continues to be built around the building block model and the treatment of capital expenditure through the RAB and recovery of opex. This framework may favour

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170 AEMC, *Electricity network regulation review,* AEMC, 2025.

171 AER, *Consumer Energy Resources Taskforce consultation – National CER Roadmap exempt – Redefine roles for market and power system operations,* August 2025.

capital intensive solutions, which are more established and predictable, rather than procured, contracted or distributed alternatives, where those alternatives are harder to identify, assess and remunerate within the existing framework. Lower-cost outcomes may depend less on building new network capacity and more on making better use of existing capacity, coordinating access more effectively, and drawing on non-network or service-based responses where they can meet the underlying need more efficiently.

In practical terms, this suggests possible evolution in the framework toward more outcome-oriented incentives, more structured treatment of non-network options, and more adaptive mechanisms for testing and integrating new service models. Additionally, we may need to consider that where the issue is not solely an expenditure choice, but how coordination, access and capacity are provided, incentive-based regulatory mechanisms may be insufficient on their own, and the primary regulatory tool may increasingly need to be explicit conduct requirements governing the terms on which those functions are performed.

The analysis of alternative futures also suggests that the importance of these issues will vary with the degree of coordination and data visibility in the system. In more coordinated futures, where data is visible, planning is aligned and participants can respond to signals effectively, the framework may do more to support efficient use of existing capacity, anticipatory investment where justified, and wider use of non-network and flexibility responses. This broader shift is also reflected in the changing mix of services that participants increasingly require from networks. In a high-CER system, efficient participation may depend not only on physical flows of electricity, but also on access to granular network data, timely and transparent connection processes, clearer access conditions, better visibility of local constraints, and more dynamic signals around exports, congestion and hosting capacity.

In this context, the AER is faced with a challenge of regulating a more varied set of services, some of which are increasingly important to enabling third-party participation, competitive markets and more efficient use of the system. In less coordinated futures, where information is fragmented, planning is siloed and market participants have limited visibility of constraints and opportunities, there is a greater risk that traditional augmentation remains the default even where it is not the lowest-cost long-term solution.

Another challenge is whether the current framework remains well suited to greater risk and cost uncertainty. Future regulatory needs are likely to depend not only on the scale of demand growth, but also on how predictable that growth is, how effectively the system is coordinated, how much consumers participate in system optimisation, and how data, flexibility and planning are valued across the supply chain. At the same time, more frequent and severe climate-related events, supply chain pressures, project delivery risks and large, interdependent investment requirements place greater weight on forecasting, resilience, uncertainty mechanisms and risk allocation than in earlier periods. This raises questions about whether the current suite of pass throughs, contingent projects, reopeners and related mechanisms remains appropriately calibrated, and whether the framework can adequately value expenditure directed to resilience, preparedness and adaptation as well as more conventional network investment.

Transmission raises a related, but somewhat different, set of questions. The current framework remains more familiar and better aligned with the traditional functions of transmission networks relative to distribution; particularly large-scale long-lived infrastructure planning, cost recovery and system-wide reliability. However, the issue of neutrally assessing network and non-network responses is also relevant in transmission, particularly as a wider range of solutions may be available to address future system needs.

Transmission regulation is also being tested by the scale, pace and uncertainty of major developments under the ISP, including associated system strength, congestion and interconnector needs, as well as interaction with jurisdiction-specific arrangements such as REZ frameworks. Transmission NSPs also face cost uncertainty due to supply chain pressures, non-NEM approval frameworks and coordination with generation projects.

These developments place more weight on forecasting, coordination and risk allocation than in earlier periods. In this context, questions remain about whether the current incentive and assessment settings remain well calibrated for a period of large, uncertain and interdependent investment. The future framework may therefore need to pay closer attention to how transmission planning, financeability, uncertainty mechanisms (like contingent projects and reopeners), system support arrangements and ex post review interact with the broader incentive model.

Across both transmission and distribution, the future framework is likely to require a more explicit treatment of coordination functions. In a more decentralised and electrified system, efficient outcomes depend not only on prudent network expenditure, but on how shared capacity is allocated, how operational information is generated and used, how different parties interact with monopoly infrastructure, and how network and non-network services are combined. Existing tools such as service classification, ring-fencing, cost allocation, shared asset rules, pricing reform, investment tests and sandboxing will remain important, but they may increasingly need to be applied to services and delivery models that do not fit neatly within the assumptions of earlier network regulation.

The framework will therefore need to remain disciplined enough to constrain monopoly power, while becoming more flexible and more explicit about how it regulates coordination, access, visibility and market-facing network functions. The challenge for the next stage in this thinking is to test whether those existing instruments can continue to govern these functions as they emerge, or whether the framework is beginning to encounter activities and interfaces from which its inherited boundaries are no longer enough.

We are proactively reviewing selected guidelines and regulatory instruments and engaging with external reform initiatives to ensure the framework is still fit-for-purpose as the energy sector evolves. We are working on identifying areas where the regulatory framework could be improved to meet the needs of the future NEM and ensure that the AER continues to fulfil its purpose to ensure consumers are better off now and in the future.

A Key Regulatory Instruments

A.1.1 Overarching statutory framework

The NEL, NER and State jurisdictional frameworks provide the core legal and policy foundation for the economic regulation of electricity networks in the NEM.

The NEO and the revenue and pricing principles in the NEL orient the framework toward efficient investment in, and efficient operation and use of, electricity services in the long-term interests of consumers.

Chapters 6 and 6A of the NER then give effect to these principles through the detailed rules for distribution and transmission revenue regulation, including service classification, forms of control, building block revenue-setting, pricing and incentive arrangements.

A.1.2 Service classification and boundary regulation

These instruments define and manage the boundary between regulated network services and contestable or unregulated activities. They establish the conditions under which services are classified, costs are allocated and activities may be undertaken within or outside the regulated business. The broader objective is to support efficient investment and competition, while limiting the risk that NSPs use their regulated position to distort markets or cross-subsidise competitive activities The key instruments include:

- Service Classification Guideline (2018) – determines the regulatory treatment of network services.
- Ring-fencing Guideline (Electricity Distribution) (2025) - sets the main behavioural separation obligations for distribution NSPs.
- Cost Allocation Guideline (Distribution) (2008) - govern how costs are attributed across regulated and unregulated services.
- Cost Allocation Guideline (Transmission) (2007) - govern how costs are attributed across regulated and unregulated services.
- Shared Asset Guidelines (2025) – deal with how consumers share in benefits where regulated assets are also used for other services.
- Distribution Service Classification Guideline and Asset Exemption Guideline (2018) – sets out classification for distribution services and exemptions.
- Trial Projects Guidelines – Regulatory Sandboxing (2023) - provide a controlled pathway for testing innovative services or business models under time-limited regulatory sandbox arrangements.
- Connection Charge Guideline (2024) - supports boundary regulation by setting expectations for how connection costs are allocated between connecting parties and the shared network.
- Exempt Networks Guideline (2025) - defines when network activities may operate outside full NSP registration, while imposing conditions to protect customers and manage interactions with the broader network framework.

A.1.3 Incentive-based regulation and the building block model

These instruments establish the framework for revenue regulation, guide expenditure assessment and forecasting approaches and determine key inputs such as rates of return and financing assumptions. Key instruments include:

- NER (Chapters 6 and 6A) - establish the legal basis for network revenue regulation, including the building block model, control mechanisms and expenditure criteria.
- Better resets handbook – supports improved regulatory proposals through earlier engagement and clearer expectations on evidence and consumer participation.
- Rate of Return Instrument (2026) - sets the method for determining the allowed return on capital.
- Expenditure Forecast Assessment Guideline (2024) - explains how the AER tests proposed capex and opex before allowances are set.
- Financeability Guideline (2024) – supports key inputs to the revenue determination process.
- Forecasting Best Practice Guidelines (2020) - supports key forecasting related inputs to the revenue determination process.
- Rate of Return Annual Updates (2026) - sets the method for determining the allowed return on capital.
- Guidance on amended National Energy Objectives (2023) – explains how emissions reduction considerations are incorporated into relevant AER decisions.
- Regulatory tax approach review (2013) – supports key inputs to the revenue determination process.
- Review of treatment of inflation (2020) – gives guidance of treatment of inflation and related indexing in revenue determination process.

A.1.4 Ex ante with ex post monitoring

These instruments support a framework in which key benchmarks are set up front, but actual outcomes are monitored and, in some cases, adjusted over time. They support a regulatory framework that combines the up-front decision making with ongoing monitoring and review mechanisms. Allowances are generally determined ex ante to provide certainty and incentives for efficient decision making and investment from NSPs, while ex post process help assess outcomes, maintain accountability and address circumstances where actual performance differs from expectations.

Key instruments include:

- Capital Expenditure Incentive Guideline (2025) - clarifies how ex ante capex incentives interact with later ex post review, including treatment of overspends, underspends and some ex post exclusions.
- Annual pricing proposal approval processes - approvals check whether network prices remain consistent with the applicable determination.
- Annual benchmarking reports - provide an ongoing evidence base on relative efficiency and productivity across NSPs.
- Confidentiality Guideline (2017) - supports these processes by governing how confidential information is handled in AER regulatory decision-making.

A.1.5 Uncertainty mechanisms

These instruments allow certain changes in circumstances to be addressed within the regulatory period without reopening the entire determination. They include cost pass throughs for defined events beyond the NSP’s reasonable control, contingent project mechanisms for projects excluded from base allowances because of uncertainty about timing, need or cost, and reopening mechanisms available in specified circumstances. Together, they preserve the overall incentive-based structure of the framework while allowing more targeted adjustment where strict reliance on ex ante allowances would allocate risk inefficiently or create poor outcomes. Key instruments include:

- NER Chapter 6, including cost pass through provisions, contingent project provisions, and provisions for reopening or substitution of determinations in specified circumstances.
- AER pass through, contingent project, and reopener decisions.

A.1.6 Performance-based incentive schemes

These instruments shape how NSPs are rewarded or penalised for expenditure and service outcomes during the regulatory period. Performance-based incentive schemes exist to provide financial incentives for NSPs to align their expenditure, service quality and innovation outcomes with regulator instructions in the regulatory period. Together, they are intended to strengthen incentives for efficient decision-making by linking financial outcomes to performance, while maintaining accountability to consumers and broader regulatory objectives. Key instruments include:

- Expenditure Incentives Guideline (2024) - supports the operation of the EBSS and CESS.
- Service Target Performance Incentive Scheme (2025) - sets the service performance incentive framework, particularly for transmission.
- Review of Incentive Schemes for Regulated Networks (2023) – sets the service performance incentive framework for distribution NSPs in relation to customer service outcomes.
- Distribution NSP Customer Service Incentive Scheme (2020) – sets out financial incentives for businesses to implement cost-effective, non-network alternatives to meet demand.
- Demand Management Innovation Allowance Mechanism (distribution) (2017) – support demand management and non-network innovation, including trials and projects that may reduce barriers to efficient alternatives to network investment.
- Demand Management Innovation Allowance Mechanism (transmission) (2026) – support demand management and non-network innovation, including trials and projects that may reduce barriers to efficient alternatives to network investment.
- DER integration expenditure guidance note (2022) - supports assessment of expenditure related to DER integration.
- Reliability Instrument Guidelines (2025) - relate to the AER's role in reliability-related processes.
- Demand Management Incentive Scheme (2017) – sets out financial incentives for businesses to undertake efficient expenditure on non-network options relating to demand management.

A.1.7 Investment assessments and non-network alternatives

These instruments govern how major investment needs are assessed and how network and non-network options are identified and compared. Together, they seek to improve the transparency, quality and consistency of investment decisions by providing frameworks for identifying needs, assessing costs and benefits and testing whether proposed investments are in the long-term interests of consumers. The key instruments include:

- Regulatory Investment Test for Transmission and Distribution, including RIT-T Application Guidelines (2024) and RIT-D Application Guidelines (2024) - set expectations for option development, consultation and supporting analysis.
- Cost Benefit Analysis Guidelines (2024) - establish the analytical framework for assessing classes of costs and benefits, especially for actionable Integrated System Plan projects.
- System Security Network Support (SSNS) Payment Guideline (2024) - supports assessment of prudent and efficient expenditure on transmission support arrangements.
- Network Alternative Support Payment Guideline (2026) - addresses the treatment of payments to non-network option providers.

- Industry Practice Application Note: Asset Replacement Planning (2024) - relevant in shaping how replacement needs are framed and assessed.
- Customer Export Curtailment Value Methodology (2022) – supports assessment of the impacts and value of export curtailment for CER customers.
- Revenue Determination Guideline for NSW Non-contestable Projects (2024) – sets out the framework for assessing and determining revenue for NSW non-contestable projects.
- NSW Contribution Determination Guideline (2024) – establishes approaches for determining customer and proponent contributions to project costs under NSW arrangements.
- Valuing Emissions Reduction Final Guidance (2024) – provides guidance on how emissions reduction benefits may be considered within investment assessments.
- Guidance note on the AER’s EII Assessment Approach for Non-contestable Revenue Determinations (2024) – outlines the AER’s approach to assessing expenditure and project costs for non-contestable projects.
- Guidance Note on Amending the Post Tax Revenue Model in NSW Roadmap Determinations (2024) – supports consistent treatment of model amendments in NSW roadmap revenue determinations.
- Non-disclosure Guideline – Electricity Infrastructure Investment Act 2020 (NSW) (2024) – establishes arrangements for handling confidential information under NSW infrastructure investment processes.
- Efficient management of system strength framework guidance note (2024) – provides guidance on applying the efficient system strength framework and assessing related investment needs.
- Guidance note on regulation of actionable Integrated System Plan projects (2024) – clarifies the regulatory treatment and assessment approach for actionable ISP projects.
- Social licence for electricity transmission projects directions paper (2023) – explores approaches to strengthening stakeholder engagement and community acceptance of transmission development.
- RIT-T threshold reviews – examine whether current threshold values remain appropriate for triggering regulatory investment assessment requirements.
- ISP transparency reviews – consider opportunities to improve transparency and stakeholder understanding of Integrated System Plan processes and outcomes.
- Better Resets Handbook (2024) – supports improved regulatory proposals through earlier engagement and clearer expectations on evidence and consumer participation.
- Values of Customer Reliability (2024) – provides estimates of the value customers place on reliability outcomes to support investment and cost-benefit assessments.

A.1.8 Pricing and network use

These instruments govern how allowed revenue is translated into prices and how newer forms of network use are reflected in pricing and operational arrangements. Together, they help translate allowed revenues into pricing structures that promote efficient use of existing networks, while also adapting to energy challenges associated with CER integration and two-way energy flows. Key instruments include:

- Pricing Methodology Guidelines (2025) - particularly relevant to transmission pricing and interconnector cost allocation.
- Export Tariff Guidelines (2022) – relevant to network export tariff rates relevant to distribution and CER integration.

- Export limit guidance note (2024) – relevant to how networks use export limits to manage hosting capacity relating to distribution and CER integration.

A.1.9 Consumer protections and service obligations

These instruments govern how NSPs interact with customers in delivering essential services They set minimum standards of service, consumer protections and information requirements to help ensure essential services are delivered in a safe, reliable and transparent manner whilst also safeguarding the interests of all consumers. There are also other obligations set through broader retail and jurisdictional frameworks rather than network regulation alone. For instance, in South Australia, distribution licence conditions and the Guaranteed Service Level scheme administered by Essential Services Commission of South Australia set minimum standards for reliability and customer service, including payments to customers for events such as prolonged or frequent outages, and requirements on distributors to provide timely information to customers about supply interruptions and restoration. The key instruments include:

- National Energy Retail Rules - govern the sale and supply of energy from retailers and distributors to customers.
- Jurisdictional service standards, licence conditions and customer information requirements.
- Export Limit Guidance Note (2024) - relevant to how networks use export limits to manage hosting capacity relating to distribution and CER integration.

A.1.10 Stakeholder engagement

These instruments and processes shape how regulatory decisions are developed, tested and applied in practice. They are intended to strengthen evidence-based decision-making by improving the flow of information to regulators and NSP decision makers, thereby reducing information asymmetries, and increasing transparency, legitimacy and accountability. Additionally, they help ensure consumer preferences and community views are made known and taken into consideration at the decision-making level. Key instruments include:

- NEL consultation requirements – establish formal consultation obligations for regulatory processes and support stakeholder participation in decision-making.
- NER consultation requirements for determinations, guideline reviews and related processes – set procedural requirements for consultation across determinations, guideline development and other regulatory activities.
- Better Regulation reforms – introduced measures aimed at strengthening consumer engagement, improving transparency and supporting evidence-based regulatory decision-making.