

FINAL REPORT

Are electricity network investment regulatory processes fit-for-purpose in Australia? Procedural and substantive review of network investment processes in the NEM



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The authors of this report would like to respectfully acknowledge the Traditional Owners of the ancestral lands throughout Australia and their connection to land, sea and community. We recognise their continuing connection to the land, waters, and culture and pay our respects to them, their cultures and to their Elders past, present, and emerging.

What is RACE for 2030?

[RACE for 2030](#) is a 10-year cooperative research centre (CRC) with \$350 million of resources to fund and support research towards a reliable, affordable, and clean energy future.

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The authors have used all due care and skill to ensure the material is accurate as at the date of this report. The authors do not accept any responsibility for any loss that may arise by anyone relying upon its content

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Executive Summary

This report examines whether Australia's existing regulatory framework for distribution network investment in the National Electricity Market (NEM) remains fit for purpose amid an accelerating and increasingly uncertain energy transition. Rather than offering a high-level policy statement, the report undertakes a systematic procedural and substantive mapping of the institutional architecture governing network investment - tracing information flows, planning horizons, and regulatory requirements across Chapters 5 (physical planning) and 6 (economic regulation) of the National Electricity Rules (NER), and examining the role of market institutions within that framework. It should be read alongside its companion comparative literature review (Cserekyei and Kallies, 2026), which situates the Australian framework against international experience.

The review identifies four principal areas where the current framework may fall short of being fit for purpose:

Institutional design. The multiplicity of rule-making and review bodies, combined with the prescriptiveness of the NER relative to comparator jurisdictions, constrains the AER's and AEMC's ability to adapt the framework quickly. Reform proceeds through piecemeal, reactive rule changes rather than proactive, holistic reassessment - a structural feature of the NEM's institutional design rather than a temporary shortcoming.

Disconnect between planning and economic regulation. Chapters 5 and 6 of the NER are only formally linked to a very limited degree, producing overlapping and at points duplicative assessment of the same investment decisions across physical network planning, the five-year economic forecast, and the Regulatory Investment Test (RIT-D). The forthcoming shift to a 20-year Distribution Network Development Plan addresses long-run physical planning, but leaves the five-year economic forecasting horizon unchanged, creating a "horizon problem" (mid-term-only investment) and a "level of detail problem" (difficulty deviating from mid-term forecasts).

Incentive regulation inefficiencies. Australia's suite of main incentive schemes including the EBSS, CESS, STPIS, CSIS, DMIS – and DMIAM, which functions as an allowance scheme - has developed piecemeal and can work at cross-purposes. A persistent capital-expenditure bias remains only partially addressed.

Contestability and the DNSP-to-DSO transition. Service classification boundaries are increasingly tested by emerging non-network alternatives, and networks are already engaging in contestable activities (e.g., EV charging, storage) via a ring-fencing waiver system. The formalisation of a Distribution System Operator (DSO) role raises unresolved questions about how competing incentive schemes should be reconciled.

The review arrives at a moment of unusually dense regulatory activity: the AEMC's Network Regulation Review (Packages 1 and 2) and the AER's Future of Electricity Network Regulation information paper and ring-fencing review are all live. These processes are, in principle, well placed to address the contestability, ring-fencing and incentive-design findings above, but

neither package squarely addresses the planning–investment interface finding - the risk being that reforms improve incentive and boundary settings without resolving the underlying duplication and rigidity in how investment need is identified and approved.

The report concludes that all four areas warrant further, more detailed research, and that while they can be researched separately, reform proposals will need to account for the interactions between them. Individual, piecemeal rule change proposals will not, on their own, be sufficient to prepare the framework for the future.

1. Introduction

Energy transitions support several objectives. They are critical to achieving energy supply security in era of increasingly volatile global energy markets. Recent geopolitical disruptions affecting global energy markets, in particular oil supply, have highlighted the vulnerability of fossil fuel supply chains. Macroeconomic shocks arising from overreliance on imported fossil supplies have contributed to fuel and associated product shortages and price volatility.

Energy transitions are also essential in mitigating climate change and (associated) environmental degradation. The substitution of fossil fuel resources with low-emissions alternatives has the potential to significantly reduce greenhouse gas emissions (as well as PM_{2.5}, PM₁₀, NO_x and SO_x pollutants) compared to a status quo. Enabling as well as regulating the energy transition has become a key purpose of energy regulation/policy.

Australia has committed to emissions reduction at both federal and state levels. The Australian Government has committed to reducing greenhouse gas emissions by 43 per cent below 2005 levels by 2030 and achieving net-zero emissions by 2050, with legislated targets in section 10 of the *Climate Change Act 2022* (Cth)). Several states also adopted ambitious legislated targets to achieve a net zero emissions by 2045-2050.¹ The National Energy Objective (NEO) - the objective governing energy regulatory frameworks - has been expanded in 2023 to reflect these national and subnational pledges.

Energy transitions encompass not only the electricity generation sector but span the entire economy. Increased electrification across industrial processes, transport systems, and residential energy use alongside simultaneously rising electricity consumption from digital infrastructure is expected to drive sustained growth in electricity demand over coming decades (AEMO, 2026), requiring significant investment in physical generation and network infrastructure. AEMO's 2026 Integrated System Plan (ISP) identifies the need for 6000 km of new transmission network infrastructure by 2050 under the Step Change scenario as well as 5 times the current grid capacity of wind and solar (AEMO, 2026).²

Sufficient network infrastructure is essential to facilitate this economy-wide growth in electricity demand and cope with different spatio-temporal generation patterns. Networks are regulated monopolies, subject to meticulous investment planning requirements and a regulatory framework seeking to provide a regulated return on their investments. At the same time, their infrastructure planning inherently involves high uncertainty about demand growth,

¹ See the *Climate Change (Net Zero Future) Act 2023* (NSW) s 9; the *Climate Change and Greenhouse Emissions Reduction Act 2007* (SA) s 5; *Climate Action Act 2017* (Vic) s6 commits to a 2045 net zero target.

² We note that the ISP projections can differ markedly between both ISPs and scenarios. For example, in 2024, AEMO projected the need for 10,000 km under the Step Change scenario. We also acknowledge that the ISP as of 2026 includes opportunities within the distribution network space, where these are the most cost-effective solutions.

asset conditions, technology costs, and regulatory and policy changes. External, macroeconomic uncertainty is also amplified under these accelerated transition conditions.

Over the past two decades, electricity networks have faced several - partly interrelated - challenges that fundamentally altered both the nature and scale of required investment. The rapid uptake of distributed energy resources - including rooftop solar, battery storage, and other forms of embedded generation - has transformed many consumers into “prosumers,” reshaping demand patterns and introducing increasingly complex, two-way power flows across distribution networks, decreasing minimum intraday demand, and voltage challenges. At the same time, state and federal energy policies (Csereklyei and Say, 2026) alongside technological development have driven the large-scale integration of utility-scale variable renewable generation, with the share of non-hydro renewables in the NEM increasing from 2.2 % in 2010 to 37.1 % in 2025. (OpenElectricity Tracker, 2026)

Further electrification in industry and residential sectors as well as the emergence of data centres are expected to drive significant increases in future total maximum or peak demand. Consequently, both maximum and minimum demand levels are expected to become more “extreme” and result in increased volatility and operational complexity, putting a strain on network services and network utilisation levels.

Under these circumstances network investment planning and execution, - still largely carried out by the same processes and within the same regulatory framework that were established over 20 years ago in a technological, and socio-technical landscape that looked very different from today’s - are becoming increasingly difficult.

The central research question of this project is whether existing regulatory frameworks governing network investment in Australia remain *fit for purpose* in this rapidly evolving energy environment. In this context, *fit for purpose* refers to the extent to which regulatory arrangements are capable of facilitating timely, efficient, and forward-looking investment that meets both current system needs and emerging challenges. We will investigate *whether current regulatory frameworks merely sustain existing network functions, or whether they are adequately designed to enable and support the broader energy transition?*

We are here concentrating on the regulatory frameworks for distributions networks. While transmission network regulation has been transformed with the advent of ISP actionable projects and the introduction of Renewable Energy Zones, a rethinking of the role of distribution networks is lagging behind. We note that this work is a general account of distribution network regulator frameworks. Significant differences exist between energy transition challenges for networks in regional and rural areas and in metropolitan areas. Whether and how a future regulatory framework can be designed in a way that addresses these differences in a fair and just way, should be considered in future research.

While discussions of potential Distribution System Operator models are underway (Energy Catalyst, 2025), this work presents a timely review of the current frameworks to identify gaps and inconsistencies. Where this report refers to networks and network investment, it refers to distribution networks, unless expressly specified otherwise.

We contribute to the literature in several key ways. We examine network investment processes from both procedural and substantive perspectives to identify where and how we may better support the current energy transition. In doing so, we map data and information flows, planning horizons, and regulatory requirements under the National Electricity Rules (NER), with particular attention to the (lack of) interplay between processes provided for in Chapters 5 and 6. We analyse the interactions with the Australian Energy Regulator (AER), including its statutory role and exercise of discretion within the regulatory framework. We also examine the required level of detail in network planning, the recoverability of efficient investments, and the effectiveness of existing efficiency investment schemes available to network businesses. Lastly, we systematically map end-to-end processes across Chapters 5 (physical investment) and 6 (network regulation) of the NER, restate known issues in the literature and practice, and identify additional, previously underexplored inefficiencies and gaps.

This report is structured as follows: Section 2 provides the regulatory background surrounding networks, Section 3 analyses network investment and investment planning processes, Section 4 throws light on the key procedural and substantial challenges in the current system and Section 5 concludes.

2. A background to the regulatory framework governing networks

Electricity distribution (and transmission) networks in Australia operate and invest in a tightly regulated environment. This section introduces the historical development of the regulatory and institutional frameworks surrounding networks in the Australian National Electricity Market – the NEM. In particular, we detail how the market liberalisation of the 1990s has informed and shaped the current governance structures and investment regulation for networks.

In this paper we use the term “NEM” to describe the integrated electricity system,³ stretching across five states⁴ and the Australian Capital Territory on Australia’s East Coast. Western Australia and the Northern Territory operate their own electricity systems which are not physically interconnected with the NEM and have separate regulatory frameworks and governance structures. These regulatory frameworks are not a focus of the report.⁵

³ The term National Electricity Market can also mean the “wholesale exchange operated and administered by AEMO...”, see *National Electricity Law* section 2, Definitions, which expressly sets out the two possible meanings of the term.

⁴ South Australia, Victoria, Tasmania, New South Wales, the Australian Capital Territory and Queensland.

⁵ We acknowledge that Western Australia has been able to flexibly react to transition pressures. Future research should assess which conditions supported this flexibility – examining industry structures, regulatory settings or particular geographical conditions.

2.1. Electricity market liberalisation in Australia: The context

The current regulatory model for network investment must be understood against the backdrop of electricity market liberalisation in the 1990s.

Electricity supply is an essential service that encompasses electricity generation, its transport through transmission and distribution networks, and the provision of electricity to end users. Historically, these functions were jointly provided by state-owned, vertically integrated and state-regulated electricity utilities in Australia.⁶

Pre-market reforms, state-owned utilities were exempt from competition law. For example, in Victoria, the State Electricity Commission (SEC) was legally authorised to decide whether or not it would allow the creation of potential rival organisations and to take over private companies when their franchise to generate and distribute electricity expired (Abbott, 2006). In return, state utilities, such as the SEC, were expected to provide reliable and affordable services consistent with their role as essential service providers. They held responsibility for system-wide planning and investment decisions for both networks and generation within their designated areas (Cantley-Smith, 2009). This coordinated approach enabled alignment between generation and network development, an issue that is currently constituting a key challenge in liberalised markets, especially with respect to the strategic siting of renewable generation assets. In Australia, and elsewhere pre-liberalisation electricity prices were set to cover the cost of the utilities, an approach called “rate of return” or “cost of service” regulation (Baldwin, Cave and Lodge, 2012). These constructs were to change with a worldwide push to liberalise electricity markets.

The purpose behind the liberalisation efforts across most of Europe and North America has been the anticipated increases in efficiency, customer value and short- as well as long-run resource allocation (Borenstein and Bushnell, 2015; Csereklyei and Kallies, 2024; Burger et al., 2019a). The textbook model for electricity reform was described by a number of authors, (Littlechild 2006; Newbery 2002, Joskow 2006), the central elements of which include:

- *privatization* to enhance performance and reduce the ability of the state to use these enterprises to pursue costly political agendas;
- *vertical separation* of competitive and regulated monopoly sectors to facilitate competition and regulation;
- *horizontal restructuring* to create an adequate number of competing generators and suppliers;
- designation of an *independent system operator* to maintain network stability and facilitate competition;

⁶ Originally the system was characterised by centralised generation and network infrastructure operated by vertically integrated utilities. The centralised nature of the network is now rapidly changing due to the uptake of utility-scale renewable electricity generation and active prosumerism. Network infrastructure designs have thus also come under pressure to cope with these challenges. It is important to recognise that the regulatory framework of the NEM we are describing here emerged at a time where these challenges did not exist.

- creation of voluntary energy and ancillary services *markets and trading arrangements*, including contract markets and real-time balancing of the system;
- application of regulatory rules to promote access to *the transmission network* and incentivize efficient location and interconnection of new generation facilities; and
- creation of *independent regulatory agencies* with adequate information, staff and powers, and duties to implement incentive regulation and promote competition.⁷

Market liberalisation has led to profound changes in market structure and in the governance of the electricity sector. Key elements of the reform have included the administrative and in many cases ownership separation of generation, transmission, distribution network operation and electricity retail operations. This process is not unique to Australia and is commonly referred to as the “unbundling” of electricity sector functions. Extensive regulatory frameworks have emerged to support the unbundling process and to facilitate the coordination between the different functions of the market.

While competition has been introduced to electricity generation (through the introduction of wholesale electricity markets) and to a large degree in retail markets, transmission and distribution networks were considered natural monopolies, and thus remained tightly regulated. A “natural monopoly” is one where “the entire demand within a relevant market can be satisfied at the lowest cost by one firm, rather than by two or more” (Posner, 1969, p.548). While competition generally serves consumer interest, it has been noted that especially in industries with substantial infrastructure needs and large-scale economies it can be “prohibitively expensive” (Brown and Sappington, 2025, p.18). Distribution and transmission networks were considered to be such industries⁸, therefore “consumers can be better served by well-designed regulation than by competition” (Brown and Sappington, 2025, p.18).

Third-party access to networks and incentive regulation are among the central aspects of these regulatory frameworks (Kallies, 2023). The economic and legal assumption underlying these regulatory settings was that network regulation can mimic a competitive market (Jamashb and Pollitt, 2007, p 6163), or, as Outhred (1998) poses, regulation provides competition “by proxy” (Outhred, 1998, p. 15). Economic theory defines the regulator’s goal as increasing social welfare (Joskow, 2014; Brown and Sappington 2025). In theory this can be achieved by replicating competitive discipline by making sure that the networks “*employ the most efficient production technology, deliver the welfare-maximizing levels of service quality, and set prices that ensure*

⁷ Further aspects include *unbundling of retail tariffs* and rules to enable access to *the distribution networks* in order to promote competition at the retail level; specification of *arrangements for supplying customers* until retail competition is in place; and provision of *transition mechanisms* that anticipate and respond to problems and support the transition rather than hinder it.

⁸ Although, as will be seen in Section 4 of this paper, whether this is still the case is an area of discussion.

(only) a normal return for the network when it operates efficiently (i.e., at minimum cost)” (Brown and Sappington, 2025, p.18).

The ability of the regulator to do so, however, hinges on their knowledge of relevant information about available production technologies and their inherent costs, the level of “normal profits”, as well as consumer preferences (Brown and Sappington, 2025, p.18). This information, however, sits with the regulated firm. Joskow (2014) identifies this information asymmetry about inherent costs and managerial effort as a key challenge for incentive regulation to overcome. Good incentive regulation therefore requires rules that induce regulated firms to use their privileged information in pursuit of regulatory objectives (Brown and Sappington, 2025). These regulatory objectives are traditionally focussed on consumer costs, but can include goals such as service quality, efficient levels of capital investment, promotion of non-network solutions and DER, or environmental goals. Across jurisdictions, several different types of network and incentive regulations have been employed over time, to reach the same regulatory objectives.

The following subsections will introduce the Australia specific developments associated with electricity market liberalisation, with particular focus on networks and the gradual emergence of the governance frameworks of the NEM.

2.2 State-level restructuring

As noted in Section 2.1, in Australia, prior to liberalisation state-based monopolies such as the *State Electricity Commission of Victoria*, the *Electricity Commission of New South Wales*, or the *Electricity Trust of South Australia*, operated separate electricity supply systems and exercised exclusive control over electricity generation, transmission and distribution to all end users (Cantley-Smith, 2009). With technological progress, initially localised grid systems were gradually interconnected to form state-wide networks. Nevertheless, for an extended period⁹ these systems remained physically isolated from one another, and “each state governed its electricity industry exclusively according to its own priorities, e.g., promoting the use of state resources, creating employment within the state, ensuring complete independence from other states for meeting electricity needs of the state.” (Sharma, 2003, p.1094).

By the 1980s, this highly centralised and integrated model of state-based electricity provision increasingly came under criticism. The state-owned systems were characterised by inefficiencies, including over-investment in generation capacity, excessive staffing levels, inflexible pricing structures and weak accountability mechanisms (Sharma, 2003).

⁹ Until the construction of the Heywood interconnection in 1990, the only interconnector between States was the Snowy Hydroelectric scheme, which spanned Victorian and NSW locations.

Early reform efforts in Australia as well as across many industrialised countries focused on improving the performance of state-owned electricity utilities. These initiatives included the corporatisation of public utilities to enhance efficiency and accountability, as well as, in some jurisdictions, the administrative separation of generation from transmission functions. Although these measures resulted in notable efficiency improvements for Australian state utilities in the 1980s to early 1990s (Sharma, 2003), they did not fundamentally alter the underlying structure of the electricity industry.

From the early 1990s, reforms in Australia shifted towards the creation of a nationally integrated electricity system, framed within a broader agenda of microeconomic reforms. It is important to understand that this was a gradual process, moving at different pace in the different states. During the first half of the decade, vertically integrated state utilities in Victoria - and, to a lesser extent, in New South Wales and South Australia - were disaggregated and corporatised by state governments. At this time, Victoria and New South Wales already operated limited wholesale electricity markets (Rann, 1998). Victoria also undertook the privatisation of its electricity assets. Subsequently, Queensland and NSW followed a similar path, with the Queensland Electricity Commission being disaggregated and corporatised in 1997, and the NSW Electricity Commission in 1995. However, unlike in Victoria and South Australia, privatisation efforts remained contentious and piecemeal in other states.

Building on state-level restructuring reforms, state and federal governments initiated the creation of a national scheme. An agreement designed to facilitate the establishment of a national electricity market was negotiated and agreed upon during the Council of Australian Governments (CoAG) meetings in 1993 and 1994.¹⁰ These reforms encompassed commitments to:

- the structural separation of generation, transmission, distribution and system operation;
- the introduction of customer choice of electricity supplier;
- the provision of non-discriminatory access to transmission and distribution networks;
- non-discriminatory entry for new generators and retailers; and
- the removal of legislative or regulatory barriers to interstate and intrastate electricity trade.

Notably, privatisation was not mandated as part of the reform agenda, and a mix of public and private ownership arrangements continues to characterise generation and network operations within the industry. Details on current ownership structures of networks are provided in Appendix 1.

¹⁰ CoAG was created in 1992 as the forum for cooperative arrangements among governments in the national interest.

The next section discusses the emergence of the NEM as a national scheme with its own regulatory frameworks and institutions.

2.3 The emergence of the NEM and its governance frameworks

Building on state-based reform efforts, the framework for the National Electricity Market (NEM) was established in 1996. The primary legislative instrument governing the NEM is the *National Electricity Law* (NEL). The NEM framework is given effect through the *National Electricity (South Australia) Act 1996* (SA), which operates nationally via enabling legislation enacted by each participating state. In other words, each state participating in the NEM is adopting the National Electricity Law. Through this legislation, and regulations made on its

State law or federal law – Explaining the nature of NEM frameworks

Australia is a federated country with states retaining jurisdictions over several portfolios, including energy. The reason for this is based in the restrictions of the Australian Constitution, which allows the Commonwealth Parliament to legislate only where expressly enabled by the Constitution. As energy is not expressly named as one of the subject matters delegated to the Commonwealth, it remains state responsibility (Kallies, 2021). The National Electricity Market is governed by a multi-jurisdictional, “national” scheme. The laws establishing this national scheme, its objectives and institutions are passed by all participating state parliaments. It is therefore based in state law – not federal law. Federal legislation has a role to play with regard to competition law, which is an area the Commonwealth can legislate in. The provision of third-party access to infrastructure is regulated in the *Competition and Consumer Act 2010* (Cth) pt IIIA.

As a result, the NEM relies on states all agreeing on its structure and institutions. While largely the overall framework is stable, states can and do derogate from specific regulations of the NEM framework if these do not align with state policy objectives.

It should be noted that in addition to being bound by the rules of the National Electricity Market, networks have to be licenced in each of the state jurisdictions they operate in. State licencing frameworks will require compliance with state legislation, state licence conditions and state-level networks codes.

basis - most notably the National Electricity Rules (NER) - the roles, responsibilities and obligations of market participants are comprehensively defined.

Following the creation of the NEM in 1996 with the passing of the NEL and NER in all participating jurisdictions, an overarching national institutional framework was gradually developed.

Initially, market rules were provided for in the National Electricity Code, a code of conduct approved by all the relevant state and federal ministers. An intergovernmental body, the National Grid Management Council (NGMC) was established to develop market rules. These functions were transferred to the National Electricity Market Management Company Ltd (NEMMCO) created in 1996 which managed the wholesale market. The Code was enforced by the National Electricity Code Administrator (NECA). The market was overseen by the National Electricity Market Ministers Forum, which in June 2001 was replaced by the Ministerial Council on Energy (MCE) to “provide national oversight” and to set up an independent review of energy market directions. These institutions were the predecessors of the institutional frameworks the NEM relies on today.

The current institutional structure of a separate regulator, rule maker and operator – overseen by a Ministerial Council was agreed between state governments through an intergovernmental agreement - through the Australian Energy Market Agreement (AEMA) in 2004 (AEMA, 2004). This national governance structure reflects its multi-jurisdictional character. A ministerial council comprised of all state and federal energy ministers sets strategic energy policy direction, agrees on legislative reforms to national energy laws, and oversees the national market institutions collectively.

Under the oversight of the council, the following institutions provide for the governance of the NEM:

- the Australian Energy Market Operator (AEMO), which operates the day-to-day activities of the wholesale electricity market and system and has a network planning role especially for transmission planning;
- the Australian Energy Market Commission (AEMC), which develops the NER and undertakes regular market reviews;
- the Australian Energy Regulator (AER), which ensures compliance with the network regulatory frameworks;
- An Energy Security Board (ESB) was implemented in 2017 to provide the Ministerial Council with whole of system and long-term planning advice. This body has been replaced by an Energy Advisory Panel in 2023.

Market institutions in turn are guided by the National Electricity Objective stated in Section 7 of the National Electricity Law, which provides that the objective of the National Electricity Law is

“to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:

- a. price, quality, safety, reliability and security of supply of electricity; and*
- b. the reliability, safety and security of the national electricity system; and*
- c. the achievement of targets set by a participating jurisdiction-*
 - i. for reducing Australia’s greenhouse gas emissions; or*

ii. that are likely to contribute to reducing Australia's greenhouse gas emissions.”¹¹

With the basic institutional design of the NEM set out here, the next section provides an overview of how networks are regulated in the NEM.

2.4. Network regulation in the NEM

Network regulation in Australia clearly mirrors the standard elements of market liberalisation introduced above – in particular third-party access, unbundling and incentive regulation. Standard network services provided by distribution networks include (i) conveyance of the flow of electricity through the network for consumers, (ii) network ancillary services, (iii) metering services,¹² (iv) connection services. These are provided for in the AER Electricity Distribution Service Classification guideline under NER 6.2.3A (AER, 2022). Networks have to invest into and maintain (and decommission sometimes) their physical infrastructure to carry out the above services.

A third-party access regime is provided for in part IIIA of the *Competition and Consumer Act 2010* (Cth). The NER provide additional detail for an access regime to networks in Chapter 5.

Networks have been unbundled from upstream and downstream markets in the NEM – a process largely undertaken by state governments in the late 1990s. Strict unbundling of network services is maintained through the NER, which classify network services (direct control services) in Chapter 6. These are monopoly services which can only be provided by networks. However, networks can also provide “contestable” services, which could be offered by other parties. Given the monopoly position of a network, the conditions under which such a service can be provided by the networks are tightly regulated. A ring-fencing¹³ regime maintained by the AER through a Ring-Fencing guideline (AER, 2025a) sets out narrow conditions under which waivers to operate potentially competitive services by networks can be provided. These requirements seek to address the risk of networks discriminating against third-party providers or cross-subsidising contestable services with regulated revenue (AER, 2016).

Incentive regulation has been introduced to ensure that investments and prices are efficient and prudent. The details of how regulatory control (through the AER) seeks to achieve this are

¹¹ Subsection c was added in 2023. The ministerial council subsequently agreed on a method to calculate the interim value of greenhouse gas emissions reductions to be used in considering or applying the objective. (MCE, 2024).

¹² While metering contestability was introduced in 2015, networks remain responsible for legacy meters until these are replaced, and continue to provide metering services in Victoria, which has deferred the introduction of metering contestability. AER (2022) provides a detailed breakdown of which metering services remain regulated.

¹³ The AER (2016) defines ring-fencing as ‘separation of monopoly services and contestable services where a regulated business also offers services into a competitive market.’.

described in Section 3 below. It has been argued that without constraint and oversight, networks have incentives to over-invest (“gold-plate”) in capital investment, prefer capital-intensive network solutions, and discount non-network or demand-side alternatives (Averch and Johnson, 1962; Joskow, 2014). Network services are therefore subject to economic regulation designed to replicate competitive pressures and promote efficiency. The AEMC describes the purpose of network regulation as helping “consumers by managing the potential risks of monopoly pricing” (AEMC, n.d.).

Australia has experienced a substantial network regulatory asset base (investment) growth particularly during the 2004–2018 period, in which regulated asset bases expanded significantly before demand outcomes diverged from forecasts (Simshauser and Akimov, 2019). Whether this significant expansion, (or overexpansion) was due to a combination of forecast error, jurisdictional reliability settings, and regulatory design features, rather than systematic over-capitalisation alone (Simshauser, 2025) or to the economic “drive” or rationale of networks (Kuiper, 2024), remains debatable.

The rules under which networks are investing and are remunerated for their investments are prescribed in detail in the NER.¹⁴ While Chapter 5 contains the rules for the physical planning of networks, network economic regulation, is set out in Chapter 6. The next section details the planning and economic forecasting processes under these two chapters, which together provide the regulatory framework for network investment decisions.

¹⁴ In addition, jurisdiction-specific licence conditions drive investment patterns. While an in-depth comparison between the jurisdictional regulatory settings is outside the scope of this report, we note that the overlay of NEM and additional jurisdictional requirements is a major source of regulatory fragmentation and complexity described in Section 4.2 below.

3. Investment planning and network investment: An overview

The purpose of this section is to describe the procedural steps of network investment planning and authorisation. This includes the dynamic interplay between the different forecasting, planning and investment test requirements, governed by Chapters 5 and 6 of the NER. While most of the following processes have been described previously by other authors, (e.g. Kuiper, 2024, Simshauser 2025) this has often been done in isolation, without presenting the nuances of interlinkages between different processes. In the next subsections we provide an overview of the integrated physical and economic planning and investment processes and their complex interlinkage, followed by a more detailed analysis of the annual network planning process, the economic forecast process, and the regulatory investment test. We examine in particular required information flows and the role of the regulator and external parties in this process. Our approach allows us to identify temporal, procedural and substantive challenges and areas of improvement.

3.1 Network investment regulation: Infrastructure planning, economic forecasting and their interlinkages

Figure 1 provides an overview of the regulatory processes governing network investment. On the left side of Figure 1, we depict planning and investment processes governed by Chapter 5 (Network Connection, Access, Planning and Expansion) of the NER, and on the right side of Figure 1 those governed by Chapter 6 (Economic Regulation of Distribution Services) of the NER¹⁵. While the chapters rarely refer to each other, the processes they require are interdependent.

¹⁵ Chapter 5 governs network assets requirements under different conditions whereas, Chapter 6/6A sets out rules on investment sums, return-on-investment, depreciation, monetary incentives and corresponding tariff settings. Chapter 5 is ultimately concerned with the physical and technical reality of network planning and investment, whereas Chapter 6 prescribes the rules governing the regulatory asset base and associated monetization. In a commercial environment, the ability to recover costs and realise profits influences the decision-making processes on what is being built. This is especially the case for investment that may be needed to react flexibly to a rapidly changing generation and demand profile.

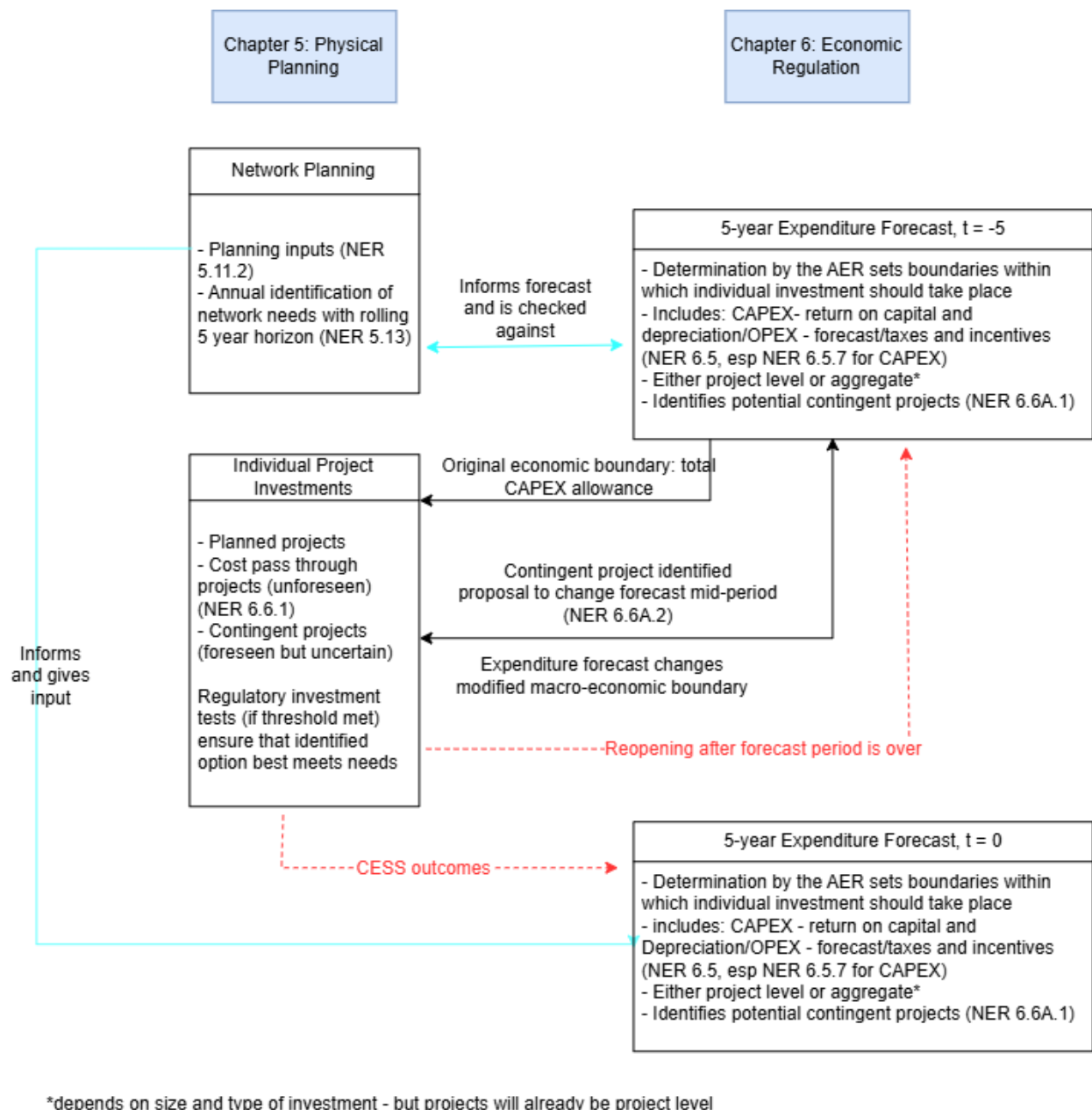


Figure 1: Network physical infrastructure planning and economic forecasting in the NER.

We define network investment here as investment needed to meet the regulatory service obligations networks face. Since electricity provision is an essential service continuous network investment either to replace and repair ageing assets, or to create new connections is required for the safe and secure supply of electricity. As mentioned in Section 2.2 networks are natural monopolies, receiving a pre-determined rate-of-return on their investments. Since they are providing an essential service without competition, the regulation of network investment activities is extensive, reaching from the exact planning of network physical needs (NER 5.13), to forecasting requirements (NER 6.3), including monetary, physical, and aggregate forecasts, rates-of-return and depreciation schedules, and the individual testing of each network project

above a certain threshold (NER 5.17). These regulations are often overlapping and require extensive documentation from networks.

Network service provision

Networks can provide a range of services – both regulated and negotiated. The NER define “distribution service” as a “service provided by means of, or in connection with, a distribution system” (NER, Glossary). “Distribution system” is defined in Section 2 of the NEL as “the apparatus, electric lines, equipment, plant and buildings used to convey or control the conveyance of electricity that the Rules specify as, or as forming part of, a distribution system and includes a regulated stand-alone power system to the extent provided by the Rules”. Networks get incentivised to provide these services by linking their provision to regulated revenue. The NEL distinguished between direct control network services¹⁶ and negotiated network services, with the AER providing further service classifications in their Electricity Distribution Service Classification Guideline (AER, 2022). The former includes typical distribution activities such as facilitating the flow of electricity through the network to the consumer. Regulatory obligations are also set out in Section 2D of the NEL:

- (1) A regulatory obligation or requirement is-
- (a) in relation to the provision of an electricity network service by a regulated network service provider-
- (i) a distribution system safety duty or transmission system safety duty; or
- (ii) a distribution reliability standard or transmission reliability standard; or
- (iii) a distribution service standard or transmission service standard.

Under s 2D (1)(b) of the NEL, this definition extends to any other obligation of requirements under the NEL, the NER or the laws and regulations of participating jurisdictions.

Physical Network Planning is a continuous process, governed by NER 5.13, taking place on an annual basis. This means that Physical Network Planning not only informs the compulsory 5-year *Economic Forecast* periods on a rolling basis but is constantly monitored against the current forecast period.

Distribution networks have a legal obligation under NER 5.13.1 to carry out physical planning for their distribution assets annually with a regulated *minimum* forward planning period of 5 years.

¹⁶ Where these services are subject to a “control mechanism based on a Distribution Network Service Provider’s total revenue requirement”, they are called standard control service (NER, Glossary, Standard Control Service).

In practice however, distribution networks already plan with a 10–15-year horizon.¹⁷ From 1 December 2027, a 20-year planning horizon will apply due to an AEMC rule change introduced to reflect the long-lived nature of network assets and the scale of expected future change (AEMC, 2026a, further detail below in Section 3.2).

Physical Network Planning on a project and aggregate level then feeds into the 5-year *Economic Forecasts*.¹⁸ These Chapter 6 processes are depicted on the right-hand side of Figure 1. NER 6.5.7 sets out detailed requirements on how capital expenditure is forecast, including information on both at project and at aggregate levels. Capital expenditure (CAPEX) is here defined as an addition to the regulatory asset base (RAB), which comprises the assets that networks use to provide their standard control services¹⁹, that will be amortised over time and carries a pre-determined rate of return (allowing for network profit).

The cost of the investment as well as the regulated return is ultimately recovered from the electricity consumer base in the form of network tariffs, that can constitute a significant part (30–40% for residential consumers (AEMC, 2025a) and more than 50% for C&I consumers (Csereklyei and Say, 2025) of the final retail electricity bill.

The 5-year *Economic Forecast* (see Section 3.3 for details) must first be approved by the AER. Once approved, it establishes the economic framework and boundary within which individual projects—typically identified either in the *Physical Network Planning* or within the 5-year *Economic Forecast* itself—can be initiated (corresponding to years $t = -5$ to 0 in our figure). The conditions under which these projects may be initiated and subsequently constructed are governed by Section 5 (see Section 3.4 for details), but they are constrained by the scope defined in the approved 5-year *Economic Forecast* ($t = -5$ to 0).

Thus, economic forecasting sets the economic framework for most of the individual investment decisions. These decisions are typically subject to a *regulatory investment test* (RIT), which evaluates projects based on their net economic benefit (NEB) and their comparative advantage over alternative (non-network) options. The RIT process is set out in more detail in Section 3.4 below.

¹⁷ In contrast, for Transmission Networks, the legal minimum forward planning period is set at 10 years, however considerable simultaneous planning is undertaken by AEMO in its Integrated System Plan, NSCAS Reports, Inertia Reports and System Strength Report, which must be taken into account by the network (NER 5.12).

¹⁸ Forecasts are required for each regulatory control period. The NER require a regulatory control period of a minimum of 5 years – see, NER Glossary: regulatory control period: “(b)In respect of a Distribution Network Service Provider, a period of not less than 5 regulatory years for which the provider is subject to a control mechanism imposed by a distribution determination”.

¹⁹ The regulatory asset base is defined in the NER, 6.1.5 as: “*The regulatory asset base for a distribution system owned, controlled or operated by a Distribution Network Service Provider is the value of those assets that are used by the Distribution Network Service Provider to provide standard control services, but only to the extent that they are used to provide such services.*” An equivalent provision for transmission networks can be found in NER 6A.6.1

We have identified three different categories of individual network investment projects – distinguished by the different treatment in the rules: 1) planned and identified projects (2) cost-pass-through projects which are necessary but unforeseen and (3) contingent projects, which are foreseen but not forecastable.

The first category includes projects planned for and identified in the 5-year *Economic Forecast* – either on individual or aggregate level. Individual project investment may then be subject to a regulatory investment test (RIT-D), if cost thresholds are met (NER 5.15.3). The second category concerns cost-pass-through projects, which were not reasonably foreseeable (NER 6.6.1, 5.17.3(c)). These types of projects will not require a standard RIT-D (NER 5.17.3(a)(1)) approval. The third category includes contingent projects (NER 6.6A.1), which are foreseen but lack sufficient specificity at the time of the forecast to be included in the revenue determination. Proposed contingent capital expenditure needs to be included in economic forecasting, including trigger events. Contingent projects can be subject to a RIT-D, if thresholds are met.

Contingent project and cost-pass through events both introduce flexibility into revenue determination. Due to the unforeseen, and/or unforecastable nature of some individual project, the regulation allows amendment of a revenue determination during, or after a regulatory control period ($t = -5$ to 0). Cost pass through and contingent project costs may be recovered in future regulatory periods if they occur at a late stage of the prevailing period²⁰.

Should one of the aforementioned categories apply, this in turn modifies the economic framework and the total allowed CAPEX and operating expenditure (OPEX), including replacement expenditure sums. Thus, both economic and (systemic) physical network planning inform the investment processes under the NER. Whether a network has surpassed the allowed investment sums or managed to stay within the allowance during a regulatory period carries consequences for future regulatory periods ($t = 0$ to 5 years) in the form of incentives or penalties under the Capital Expenditure Sharing Scheme (CESS) (NER 6.5.8A).

Network investment processes thus follow a multi-step process designed to ensure that sufficient investment is undertaken to provide safe, secure and reliable supply, while ensuring that consumers (who will have to pay for the undertaken investment through their electricity bills) are not paying for unnecessary investment. For electricity systems in transition, the questions of what is *necessary* and *sufficient* require a closer look.

We note that while there is limited cross-referencing of the network investment planning process between Chapters 5 and 6 of the NER, there is in practice substantial information flow and repeated information provision that may contribute to process inefficiencies. To make these assessments, the standard process blocks and information requirements for distribution network investment will be described and explained below. While the major steps for

²⁰ Contingent projects (if trigger event occurs, NER 6.6A.2.), cost pass through event (if AER makes relevant cost-recovery determination, NER 6.6.1).

transmission investment are similar, importantly, AEMO has a major planning role in transmission planning and investment²¹.

3.2 The Annual network planning process

We note that the processes described here are updated from December 2027 onwards following the Enhancing Distribution Planning and Reporting Rule Change (AEMC, 2026a).

Currently, the NER require DNSPs to undertake an annual planning process and publish a Distribution Annual Planning Report (DAPR) with a minimum 5-year horizon (NER 5.13.2). As already flagged above, networks usually already report with a longer horizon. From December 2027 networks will be required to report with a 20-year horizon.

The planning process allows networks to:

- identify network limitations,
- identify demand of assets,
- based on the above, identify investment needs.

Networks are required to identify network limitations based on the forecasts of supply and demand by registered participants (NER 5.11.2). Based on this information and the technical requirements of the network, each DNSP currently undertakes an annual planning review (NER 5.13.1) of expected future operations and limitations over a minimum five-year forward planning horizon for its distribution assets. If the annual review identifies the need for corrective action, the DNSP must determine whether a Regulatory Investment Test is required (NER 5.13.1(3)).

In future, the rule change²² replaces the annual DAPR with a Distribution Network Development Plan (DNDP) to be developed every 5 years (with annual updates). It also introduces changes aimed at more transparency in network planning, and better stakeholder engagement. The AER is subsequently tasked with developing guidelines setting out requirements for the forecasting practices used in the DNDP and its annual updates (new NER 5.13.3). These forthcoming changes to NER 5.13.1 will expressly require a DNSP to submit the DNDP “at the same time that it is required to submit a regulatory proposal under clause 6.8.2, submit a plan for the development of its distribution network to the AER and publish the plan on its website.”

The information required to be included in the DAPR, and in the future the DNDP and its annual updates, is extensive.

Specifically, currently, the NER 5.13.1 and Schedule 5.8 require the DNSP to provide, *inter alia*:

²¹ The AEMO models long-term scenarios and identifies an “optimal development path” in their biennial integrated system plan (ISP). The ISP also identifies actionable projects for which a streamlined RIT applies.

²² The proposed changes will commence on 1 December 2027. See AEMC (2026a) National Electricity Amendment (Enhancing distribution network planning and reporting) Rule 2026 No. 7.

- detailed information on their network assets;
- forecast for future loads and connection points, as well as the methodologies and strategies;
- RIT-Ds underway or expected;
- description of investment to be carried out in the forward planning period, including consideration of alternative options (such as demand side investment) that are to address urgent and unforeseen network issues;
- information on the performance of the network against reliability measures and standards;
- information on their asset management strategy;
- information on demand management activities;
- the development of an industry engagement strategy for “engaging with non-network providers, considering non-network options and ... SAPS options” and subsequent engagement activities (NER 5.13.1 (e)-(j)).

For the future DNDP and its annual updates, the rules require the similar information and additionally require networks to:

- adopt AEMO’s Inputs, Assumptions and Scenarios Report as the baseline for their plans;
- identify future network needs, risks, opportunities and potential non-network options; and
- explain how they have engaged with consumers and other relevant stakeholders.

While the network planning process has prescribed timelines and content, it is a network internal process. The AER does not need to approve or endorse the plan. However, many of the content requirements are part of penalty provisions – this means that if the required content is not included, the network can be penalised under the National Electricity (South Australia) Regulations.

The connection of the physical network planning under Chapter 5 of the rules to the 5-year expenditure forecasts and revenue determination under Chapter 6 is severalfold, (i) it informs economic forecasts, both on a project (e.g. feeders and substations) and aggregate basis, (ii) it is continuously monitored against the current expenditure forecast and revenue determination and the progression of investments (RAB) in the prevailing expenditure forecast, (iii) it informs future expenditure forecasts due to its rolling basis.

3.3 Economic regulation of networks: the 5-year Economic Forecast

3.3.1 Forecasting and determination process

The process followed for *5-year Economic Forecast* and regulatory determinations is set out in Chapter 6 Part E of the NER. Based on this determination, annual tariff setting/pricing proposal

(NER 6.18.2) and annual benchmarking (NER 6.27²³) is conducted. Unlike the annual planning process outlined above, this is not a rolling window but includes consecutive 5-year periods. Each network in Australia has its own 5-year regulatory control period, with networks within each state on the same schedule.

Table 1: Distribution Network Regulatory Control Periods in the NEM

State	DNSP	Current Regulatory Control Period
Queensland	Energex, Ergon Energy	1 July 2025-30 June 2030
NSW/ACT	Essential Energy, Endeavour Energy, Ausgrid, Evoenergy	1 July 2024- 30 June 2029
Victoria	Powercor Australia, Ausnet Services, United Energy Distribution, Citipower, Jemena	1 July 2026- 30 June 2031
Tasmania	TasNetworks	1 July 2024- 30 June 2029
South Australia	SA Power Networks	1 July 2025-30 June 2030

The NER also provide detailed instructions on the substance of regulatory proposals and the approach the regulator takes to assess them. Capital investment requirements are approved for each 5-year regulatory period, which provides clear fiscal and economic boundaries within which specific (individual) investments take place in the next 5 years. The associated capital and operating expenditures, depreciation on the current and forecasted regulatory asset base, and various incentives will provide the revenue requirement and determination for networks, enabling their efficient functioning. The revenue determination in turn will determine the proposed tariff structures and levels charged to different customers.

The 5-year Economic Forecast process introduced in Figure 1 is depicted in detail in Figure 2. The actual process includes consultations with external stakeholders as well as several rounds of negotiations and consultations with the AER. The forecasting process, - given the extent and level of detail of the required documentation - is a highly time and resource intensive endeavour. However, the 5-year Economic Forecast is not a stand-alone process, it is informed by the physical network planning under Chapter 5 and is informing it in turn, as well as the individual projects that a network undertakes. In future, the timing of the preparation of the

²³ NER 6.27a provides that “The AER must prepare and publish a network service provider performance report (an annual benchmarking report) the purpose of which is to describe, in reasonably plain language, the relative efficiency of each Distribution Network Service Provider in providing direct control services over a 12 month period.”

DNDP and the regulatory proposal will align, and the rules require the proposal to be submitted together with the DNDP.

Table 2 describes how the capital investment regulatory frameworks distinguish between activities undertaken and mechanisms applicable before, during and after each regulatory control period.

Table 2: Network capital investments and the regulatory control period cycle

Before	During	After
DAPR/DNDP informed Economic forecast determining economic boundaries and subsequent revenue determination (either project or aggregate level)	Investments that are either: -Planned investments -Cost pass through events -Contingent projects Networks assess events if RIT-D required	CESS incentives or penalties' Reduction for inefficient past CAPEX NER6.2.2A

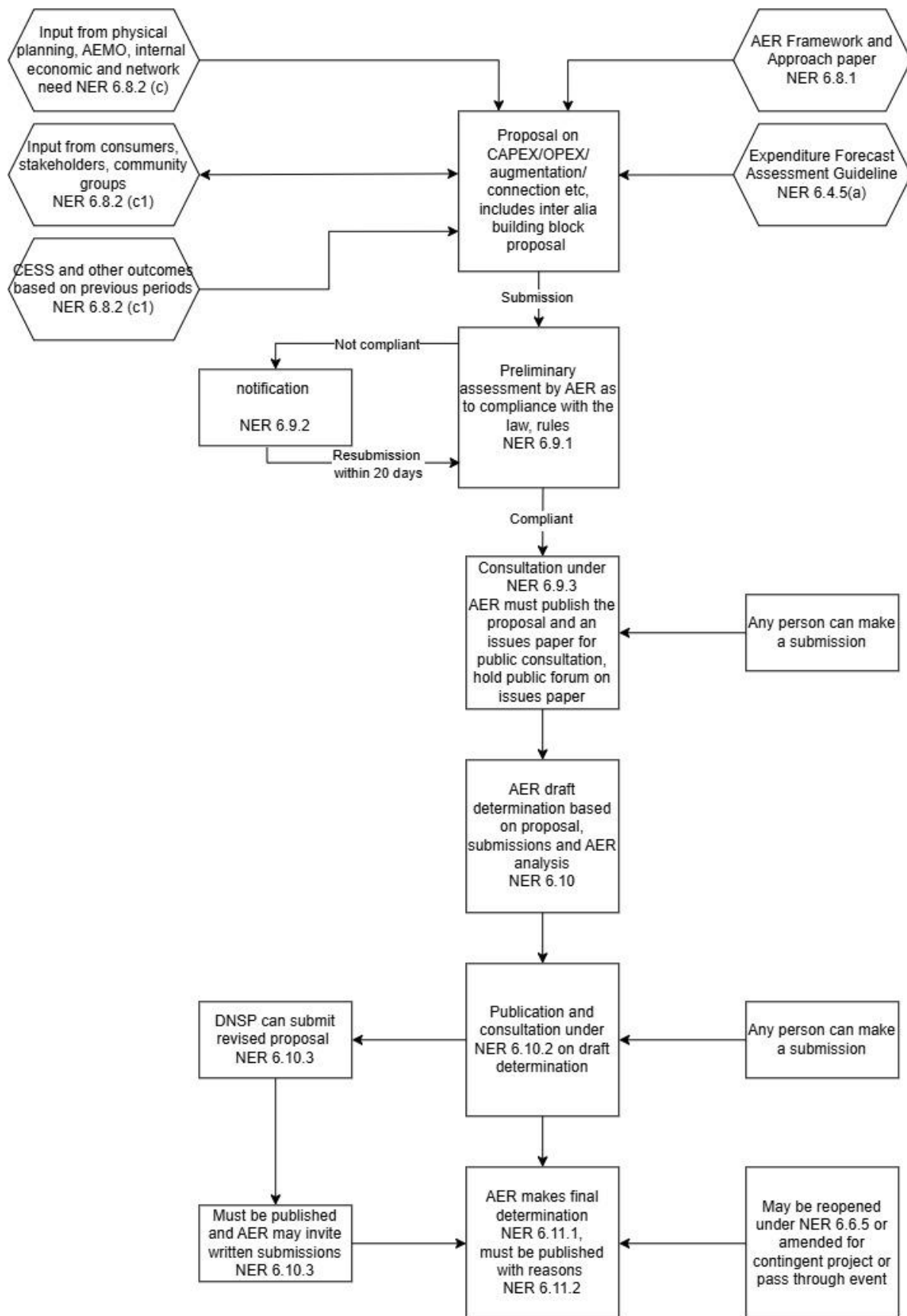
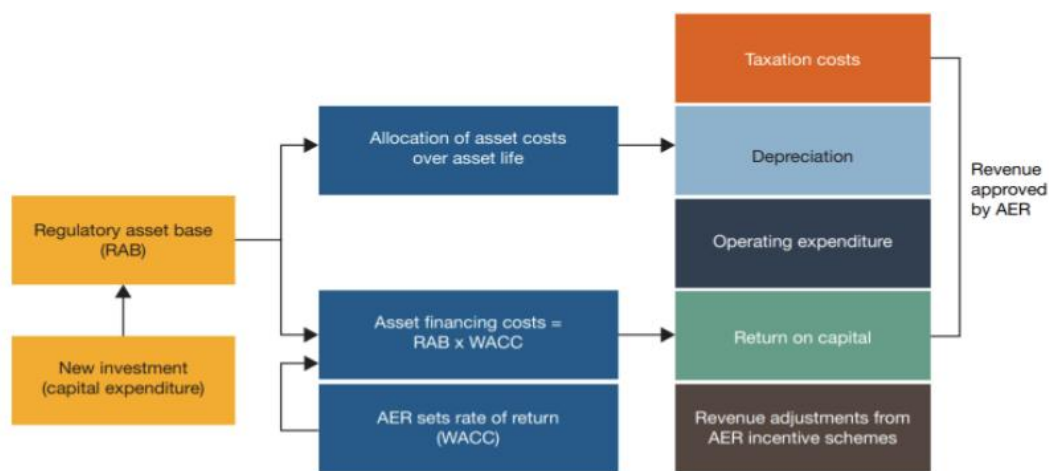


Figure 2: Economic regulation of networks: the 5-year Economic Forecast process

3.3.2 The building block approach

Australian electricity network regulation is based on the incentive regulation framework of Littlechild (1983), referred to as the RPI-X model or building block approach. The approach - originating in the United Kingdom's telecommunications sector - has been adapted to the Australian context and applied uniformly across network businesses, irrespective of ownership (Simshauser, 2025). The framework - apart from providing a pre-determined rate of return on a firm's regulated asset base - also promotes productive efficiency by setting ex ante revenue allowances and allowing firms to retain gains from outperforming regulatory benchmarks over the control period. Figure 3 lists the main components of the building block approach.



Source: AER.

Figure 3: The figure is provided by the AER in their *State of the Energy Market* (2021) report, p 134. The building blocks required for this framework are explicitly prescribed in NER 6.4.3 for distribution networks, which require the Australian Energy Regulator (AER) to determine a total revenue allowance by reference to these components and consistent with the expenditure objectives, capital expenditure criteria, and factors detailed in NER 6.5.7. Allowed revenue components include return on capital, return of capital, operating expenditure, and taxes and thereby sets the financial boundary within which network investment in the forecast period can occur.

The building block model summarises the physical network planning requirements identified in the network planning process under Chapter 5 (CAPEX forecast) into allowed revenue components, calculated as the sum of separate “building blocks,” which include: (i) the return on capital (calculated on the regulatory asset base), (ii) the return of capital through depreciation, (iii) forecast operating expenditure, (iv) forecast tax liabilities, and (v) any incentive scheme adjustments. This method ensures that network revenues reflect the efficient costs of providing electricity services while allowing a pre-determined commercial return, thereby promoting economic efficiency and transparency. While this connection is not

expressly prescribed in the rules, the RIT process, described in the next section, should fit within the CAPEX envelope of the allowed revenue determination.

The forecast capital expenditure flows into the calculation of the final regulated asset base. The RAB represents the value of regulated assets over time. To determine the revenue for a new regulatory period, the opening RAB is taken from the closing value of the preceding period and updated annually. This involves indexing the asset base for inflation, adding new capital expenditure, and deducting depreciation and other adjustments, such as asset disposals. This process produces a closing RAB value for each year of the regulatory period. The resulting RAB forms the basis for both the *return on capital* and *return of capital* building blocks.

The distribution network service provider must submit a detailed forecast of key capital projects expected over the regulatory control period (NER 6.5.7) including expenditures necessary to meet demand, comply with regulatory obligations, and maintain network reliability, safety, and security²⁴. The forecast must reasonably reflect the costs that a *prudent and efficient* service provider would incur, and it must be supported by transparent assumptions, methodology, and explanatory detail.

Additionally, a number of efficiency incentive schemes have been introduced with the purpose of incentivising networks to prioritise non-network solutions in the context of demand management. Further discussion of these schemes is provided below in Section 4.

The NER 6.5.7(c) relevantly provide that:

(c) *The AER must:*

(1) subject to subparagraph (c)(2), accept the forecast of required capital expenditure of a Distribution Network Service Provider that is included in a building block proposal if the AER is satisfied that the total of the forecast capital expenditure for the regulatory control period reasonably reflects each of the following (the capital expenditure criteria):

- (i) the efficient costs of achieving the capital expenditure objectives;*
- (ii) the costs that a prudent operator would require to achieve the capital expenditure objectives; and*
- (iii) a realistic expectation of the demand forecast, cost inputs and other relevant inputs required to achieve the capital expenditure objectives.*

²⁴ We note that while some CAPEX projects can be planned at the project level, a part of the forecasted expense is planned as a monetary aggregate.

The AER assesses the forecast against the prudence and efficiency criteria, as well as the capital expenditure factors set out in NER 6.5.7(e), such as projected demand growth, network condition, risk, potential substitution between operating and capital expenditure, to determine the capital expenditure component that feeds into the building block model.

3.3.3 Reviewing revenue determinations of the AER

Determinations of the AER used to be subject to limited merits review with the Australian Competition Tribunal. Merits review means that the tribunal had the ability to assess the merits of the decision – the tribunal could remake a decision *de novo* (within limitations) . This was not a full merit review, but the review option was somewhat limited in the NEL in regard to both matters that could be raised and grounds that the tribunal could consider.

This pathway has been closed off in 2017, with the introduction of section 44 AIA into the *Competition and Consumer Act 2010* (Cth). The section provides that:

“No merits review of AER decisions

A decision of the AER under a State/Territory energy law or local energy instrument is not to be subject to merits review (however described) by a body established under a law of a State or Territory.” Subsequently, the only legal review pathway currently available to networks to challenge an AER regulatory determination is judicial review under section 5 of the *Administrative Decisions (Judicial Review) Act 1977* (Cth), assessing whether the AER had made the decision within the boundaries of its legal powers and functions.

3.3.4 Amending or reopening determinations

When assessing whether the regulatory framework for network processes is fit for purpose, it is critical that it allows flexibility when investing under uncertain conditions. Under the NER, not all investment that falls within a regulatory control period must have been forecast in the original regulatory proposal for the period in question. Mechanisms to amend or reopen revenue determinations accommodate for unanticipated needs or projects that were not included in the ex-ante CAPEX forecast.

The key mechanisms allowing networks to deviate from determinations fall into the categories of *contingent project* applications and *cost pass through events*.

Networks may apply for the reopening of revenue determinations for the relevant regulatory period, or, if at the end of such a determination, AER may allow a recouping of costs in future regulatory periods. The rules also provide for this pathway to apply to the AER to revoke and substitute a distribution determination for capital expenditure under NER 6.6.5, for unexpected events that are neither contingent projects nor pass through events. This is the case for major

changes, that would require CAPEX that “exceeds 5% of the value of the regulatory asset base for the relevant Distribution Network Service Provider for the first year of the relevant regulatory control period” (NER 6.6.5 (4)(i)). The only example of such an application in the context of distribution networks is the now withdrawn application of Jemena in 2024 (AER, 2024a).

Contingent projects

Contingent projects are defined as projects where the need, timing and/or cost could not be reasonably determined at the time of the revenue determination (AEMC, 2020), in other words “foreseen, but uncertain”. For example, proposed contingent project capital expenditure, including their *triggers* needs to be included in the economic forecast (NER 6.6A.1(a)). Based on the proposal, NER 6.6A.1(b) prescribes that the AER will determine that the proposed contingent project is a contingent project if the project is reasonably required to achieve the capital expenditure objectives, and (a) the capital expenditure is not otherwise provided for in the accepted forecast capital expenditure; and (b) the project exceeds a materiality threshold (e.g., a monetary threshold or percentage of allowed revenue). Once the trigger event occurs, the network contacts the AER mid-period, to request an amendment to the determination during the regulatory period (NER 6.6A.2).

NER 6.6A.2 also prescribes the process for the amendment:

- Application requirements:
 - o must be made as soon as practicable after the trigger event
 - o it cannot be made later than 90 days prior to the end of the penultimate year of the regulatory period
 - o must include evidence of trigger event, and a range of detail on expenditure required
- The AER must:
 - o publish the application and allow for public submissions,
 - o assess the application, having regard to a range of information – similar to the requirements for CAPEX revenue determinations
 - o make a decision within 40 business days (this timeframe can be extended if complicated application)

If the regulatory conditions are met, the AER has to amend the revenue determination to include the capital costs for that project into the forecast, which in turn changes the economic boundaries of the current period. NER 5.17.3(c)(4) expressly excludes contingent projects from the list of RIT-D project exemptions). In summary, this mechanism allows network businesses to recover efficient costs of contingent investments when genuinely trigger events arise, but only after meeting the requirements for a contingent project application under the NER.

Cost pass through events

Networks may also be faced with a situation where network investment could not be foreseen. In this case, a cost pass through event may apply. The conditions for cost pass throughs are set out in NER 6.6.1. According to NER 6.6.1(a1) a pass through event can be

- (1) a regulatory change event;
- (2) a service standard event;
- (3) a tax change event;
- (4) a retailer insolvency event; and
- (5) any other event specified in a distribution determination as a pass through event for the determination.

For the latter, networks need to include suggested categories in their revenue proposal, and the AER needs to accept these. Typical declared pass through events are natural disasters or terrorism events, but these can be related to transition requirements.²⁵ Note that pass-through events can be negative change events (where a network incurs materially lower costs than it would have but for the event) or positive change events (where a network incurs materially higher costs than it would have but for the event). Detailed procedural instructions for pass through event are prescribed in NER 6.6.1(c)-(h). Should one of these events occur, the DNSP must apply for approval to the AER within 90 days of the event, including evidence of cost increases and that event was a consequence of the change event. The AER must make a decision and publish the reasons for the decision within 40 business days, or the AER is taken to have approved the proposal.

3.3.5 Penalties for inefficient past capital expenditure and the Capital Expenditure Sharing Scheme

The NER provide for different incentive mechanisms to assess previous performance of networks and apply the outcomes of these assessments in future regulatory periods. For capital investment these include mechanisms to penalise inefficient capital expenditure and to incentivise efficiency.

²⁵ An example of a transition-related service standard event is the implementation of Emergency Backstop Mechanism in NSW. This mechanism requires NSW DNSPs to temporarily reduce rooftop solar exports to the grid or pause generation, when instructed by AEMO. In order to develop this capability, NSW DNSP are applying for the approval of additional CAPEX and OPEX.

Reduction for inefficient past capital expenditure

As part of a revenue determination under NER 6.12.2(b) the AER has to explain “the extent to which the roll forward of the regulatory asset base as determined under clause 6.12.1(6) contributes to the achievement of the capital expenditure incentive objective.”

This allows the AER to conduct an ex-post review of CAPEX if triggered under the conditions set out in NER S6.2.2A. The clause provides for a mechanism through which the AER may reduce the amount by which an DNSP’s RAB would otherwise be increased, based on performance in the previous regulatory period.

The Capital Expenditure Incentive guideline sets out the circumstances in which this mechanism applies (AER, 2025b, p 17):

- where an NSP has spent more than its CAPEX allowance, [the AER] may exclude CAPEX above the allowance from the RAB if it does not reasonably reflect the capital expenditure criteria
- where an NSP has incurred CAPEX that represents a margin paid by the NSP, [the AER] may exclude that CAPEX from the RAB where the margin refers to arrangements that do not reflect arm’s length terms
- where an NSP’s CAPEX includes expenditure that should have been classified as OPEX as part of an NSP’s capitalisation policy submitted to us as part of a regulatory proposal, [the AER] may exclude this from the RAB.

Unlike for the CESS, explained in more detail below, the period reviewed for this mechanism is the first three years of the regulatory period just ending and two years of the preceding control period. The process for this ex-post review is prescribed in the NER S6.2.2A and the AER Capital Expenditure Incentive Guideline (AER, 2025b).

Capital Expenditure Sharing Scheme

The main policy incentive to curb network overspending is the capital expenditure sharing scheme (CESS) as set out in the AER Capital Expenditure Incentive Guideline (AER, 2025b) and passed on the basis of NER6.5.8A and 6.4A. The CESS is an ex-ante incentive with an ex-post review and seeks to ensure that “the only capital expenditure that is included in an adjustment that increases the value of that regulatory asset base is capital expenditure that reasonably reflects the capital expenditure criteria” (NER 6.4A(a)).

The CESS works by comparing forecast capital allowance for the regulatory period with the actual outcomes. If the actual CAPEX is below the forecast allowance, this is treated as an underspend (efficiency gain); if actual CAPEX exceeds the allowance, it is treated as an overspend (efficiency loss). The NER sets a sharing factor, commonly at 30%, meaning the

network keeps a portion of efficiency gains²⁶ and bears a portion of the losses. The difference is adjusted using the vanilla WACC²⁷ (weighted average cost of capital) over the regulatory period. This means, that for overspends 70 per cent flows through to consumers. Networks keep a lower proportion of the efficiency gains, however. Consumer benefits from efficiency gains are delivered primarily through lower future revenues (and thus tariffs).

However, the CESS does not protect inefficient expenditure. Where the AER conducts an ex-post review and determines that some or all of the overspend does not meet the capital expenditure criteria, the inefficient amount may be excluded from the RAB entirely, meaning the DNSP bears 100 per cent of that cost. In this way, the CESS operates alongside, rather than replacing, ex post prudence and efficiency assessments.

3.4. The Regulatory Investment Test process

The above network planning and economic forecasting sets the economic framework for individual project decisions. For projects exceeding a particular cost threshold, a regulatory investment test will be applied, which includes community engagement and requires the network to assess non-network alternatives to the proposed capital investment.

3.4.1 Content of a RIT-D

Bringing together physical planning and economic principles, the RIT-D should ensure that network investment is (a) needed and (b) at lowest cost – thereby meeting the requirement of the regulatory framework for both efficiency and consumer protection from unnecessary cost blowouts.

The purpose of the RIT-D is set out in detail in cl 5.17.1 (b) of the NER as follows:

- *The purpose of the regulatory investment test for distribution is to identify the credible option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the NEM (the preferred option). For the avoidance of doubt, a preferred option may, in the relevant circumstances, have a negative net economic benefit (that is, a net economic cost) where the identified need is for reliability corrective action.*

Under the relevant RIT clauses, proponents (DNSPs) must undertake a forward-looking cost-benefit analysis comparing costs and market benefits of credible options over a defined

²⁶ Notably, the CESS applies a non-symmetric sharing factor for large underspends. Where a DNSP underspends its total approved CAPEX allowance by more than 10 per cent, the sharing rate applied to the amount above that threshold is reduced, so that the DNSP retains only 20 per cent of that additional underspend. The AER introduced this change (after the 2023 incentive regulation review) to limit incentives for excessive under-delivery of capital programs and to strengthen the alignment of the scheme with long-term consumer outcomes, while still preserving incentives for efficient delivery.

²⁷ The "Vanilla" (or "Unadjusted") WACC strips out all tax assumptions from the discount rate. It is calculated as the simple, weighted average of the pre-tax cost of debt and post-tax equity.

assessment period, discount them to present value, and rank options accordingly; the one that maximises NEB is selected to meet the identified need. The RIT applies if a regulatory threshold is met²⁸ and follows a set of clearly defined procedural steps. It is supported by a number of guidelines provided by the AER. The AER oversees this process by setting guidelines, monitoring compliance, and resolving disputes in accordance with the NER. The AER does not have to approve the RIT.

The process for a RIT-D is prescribed in the rules and refined in several AER guidelines. Substantively, proponents will have to work through the steps presented in Figure 4.

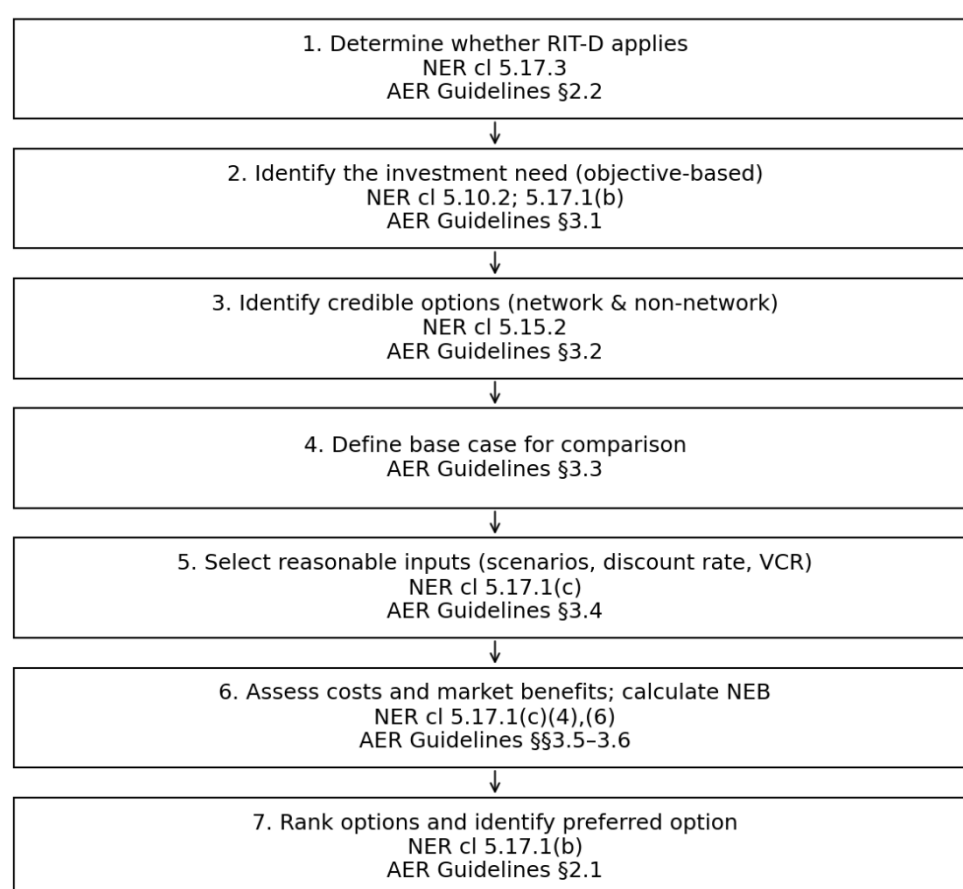


Figure 4: Substantive components of the RIT-D process

This analytical framework for the test is prescribed by clause 5.17 of the NER and is elaborated in detail in the *AER Regulatory Investment Test for Distribution Application Guidelines* (AER 2024b), which provide guidance on both procedural and substantive requirements.

Firstly, the DNSP must determine *whether the RIT-D applies*. Under clause 5.17.3 of the NER, a RIT-D is required unless one of the specified exemption categories applies, including

²⁸ Thresholds are reviewed every 3 years by the AER (NER 5.15.3). The current threshold for RIT-D projects is \$7 million (AER n.d.).

circumstances involving urgent and unforeseen network issues²⁹, projects that fall below the applicable capital expenditure threshold, or expenditure that constitutes maintenance rather than augmentation or replacement of network assets.

If the RIT-D is required, the DNSP must first identify the *investment need*, which the Rules and the RIT-D Guidelines require to be expressed as an objective, rather than as a particular technical solution (AER 2024b, pp14-15). An identified need may arise due to forecast changes in demand or generation patterns, or because reliability corrective action is required to comply with applicable service standards. These standards may be prescribed in the NER itself or in other relevant regulatory instruments, including jurisdictional reliability frameworks. This objective-based formulation is required by NER 5.10.2 and 5.17.1(b) and seeks to ensure neutrality between network and non-network solutions.

Following identification of the need, the DNSP must identify a range of *credible options* capable of addressing that need. According to NER 5.15.2 and the RIT-D Guidelines, credible options must include non-network options where feasible. An option will be credible if it (i) addresses the identified need (NER 5.15.2(a)(1)); (ii) is commercially and technically feasible, meaning that a reasonable and objective operator, acting rationally and in accordance with the RIT-D requirements, would be prepared to develop or provide the option, and (iii) is capable of being implemented in time to address the identified need. The RIT-D Guidelines further explain how proponents should consider *option value* at this stage, allowing uncertainty about future demand, technology costs or policy settings to be incorporated into the identification and assessment of options.

The DNSP must then compare each credible option against a clearly defined *base case*, representing the circumstances that would prevail in the absence of the investment. The RIT-D Guidelines (AER, 2024b, p 19 f) recognise that there may be different appropriate approaches to specifying the base case, depending on the nature of the need and the characteristics of the network, but emphasise the importance of transparency and consistency.

In conducting the cost-benefit analysis, the DNSP must identify and justify the key analytical inputs – see RIT-D Guidelines (AER, 2024b, p 20 ff). These may include, where appropriate, demand forecasts and scenarios drawn from AEMO processes such as the Integrated System Plan or National Transmission Development Plan, alongside other up-to-date, relevant and reputable information. Demand forecasts and discount rates must be applied in accordance with clause 5.17.1(c)(9)(iii) of the NER. The valuation of changes in supply reliability must use accepted estimates of the value of customer reliability, typically derived from AEMO analysis and the AER’s annually published Value of Customer Reliability (VCR) estimates, consistent with the RIT-D Guidelines.

²⁹ This would be a pass through event.

For each *credible option*, the DNSP must quantify all relevant costs over the assessment period. These include capital costs, operating and maintenance costs over the lifecycle of the option, compliance costs, and, where applicable, payments associated with demand response or other non-network service provision. These cost categories are specified in clause 5.17.1(c)(6) and elaborated upon in the RIT-D Guidelines (AER, 2024b, pp 29-32).

The DNSP must also identify and quantify the relevant *market benefits* associated with each credible option. The NER recognises multiple classes of market benefits, including changes in

Net-Economic Benefit

*The purpose of the regulatory investment test for distribution is to identify the credible option that maximises the present value of the **net economic benefit** to all those who produce, consume and transport electricity in the NEM (the preferred option). (NER clause 5.17.1(b), with related principles set out in 5.17.1(c)).*

The definition of the term in Chapter 10 sets out that the NEB is

The sum of:

(a) the net economic benefit, other than of changes to Australia's greenhouse gas emissions, to all those who produce, consume or transport electricity in the NEM; and

(b) the net economic benefit of changes to Australia's greenhouse gas emissions, whether or not that net benefit is to those who produce, consume or transport electricity in the NEM.

The NEB thereby functions as the statutory economic criterion for selecting network investments.

reliability, network losses, market operation costs and greenhouse gas emissions as per clause 5.17.1(c)(4). The RIT-D Guidelines provide further guidance on the calculation and treatment of these benefit categories. Finally, the DNSP must rank all credible options according to *their expected net economic benefits (NEBs)* and identify the preferred option as the one that maximises the present value of NEB.

3.4.2 Timelines and stakeholder engagement process

Alongside these substantive requirements, a RIT-D requires considerable public engagement activities. Figure 5 sets out the procedural steps and timelines required for a RIT-D.

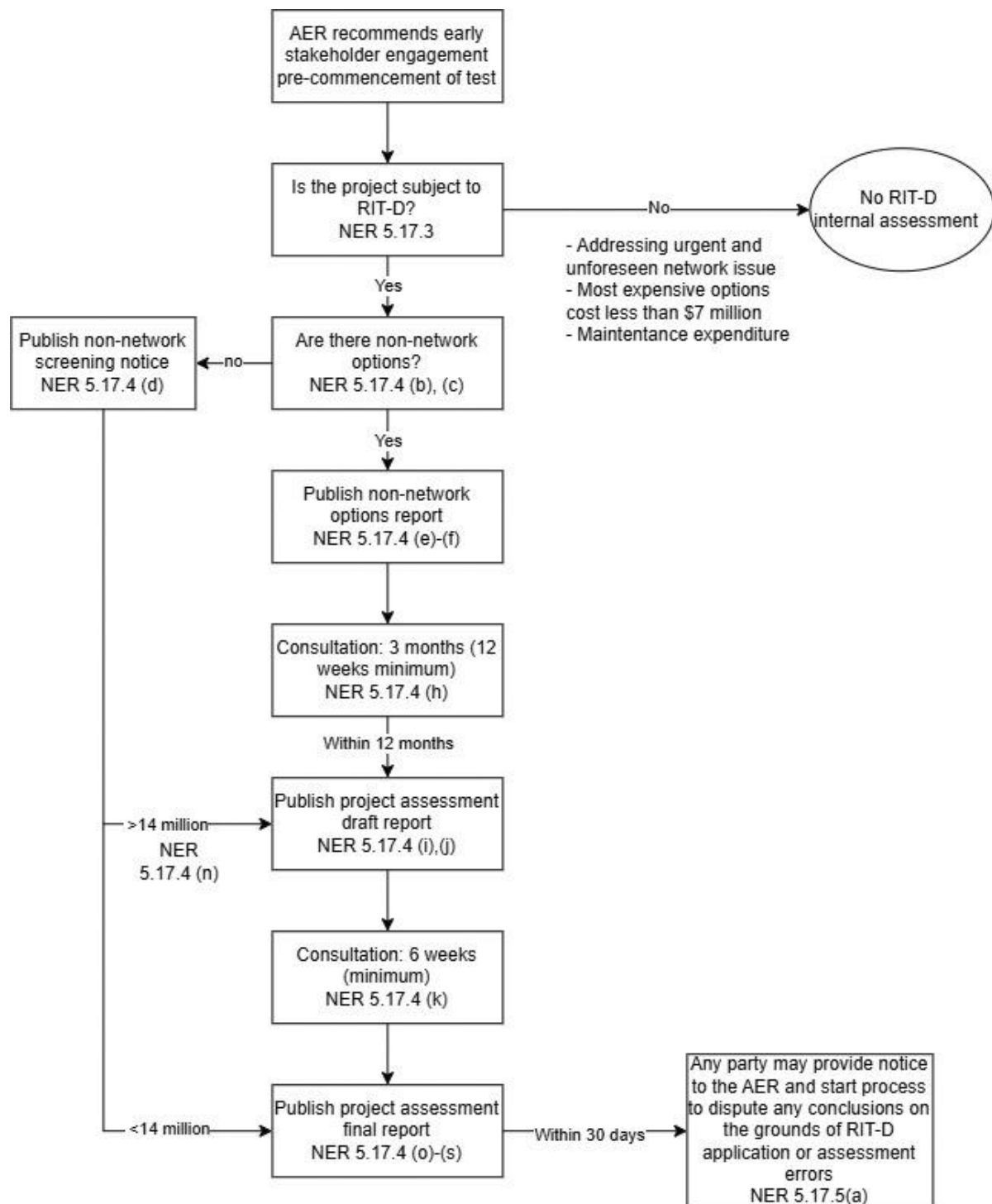


Figure 5: RIT-D procedural overview. This figure is an adapted version of Figure 1, p 60 of the RIT-D application guideline (AER, 2024b), adding regulatory provisions and updating cost-thresholds as of April 2026.

It should be noted that consultation processes under NER 5.17.4(a) are available to (1) all Registered Participants, AEMO, interested parties and non-network providers; and (2) if the RIT-D proponent is a Distribution Network Service Provider, persons registered on its industry engagement register. The dispute processes provided for in NER 5.17.5 widens the stakeholders

able to raise a dispute to “Registered Participants, the AEMC, Connection Applicants, Intending Participants, AEMO, interested parties, and non-network providers”.

Interested parties are defined in NER 5.15.1 “as a person including an end user or its representative who, in the AER’s opinion, has the potential to suffer a material and adverse NEM impact from the investment identified as the preferred option in the project assessment conclusions report or the final project assessment report (as the case may be).”

4. Discussion: Are distribution network investment regulations fit-for-purpose?

The past 20 years have seen a rapid change in the technological landscape, economic regulation, energy demand and consumer behaviour alike. These changes jointly impact on how, when and where network services are demanded.

The central research question of this project is whether existing regulatory frameworks governing electricity network investment are still *fit for purpose* in this rapidly evolving environment. *Fit for purpose* here refers to the extent to which regulatory arrangements are capable of facilitating timely, efficient, and forward-looking investment that meets both current system needs and emerging challenges.

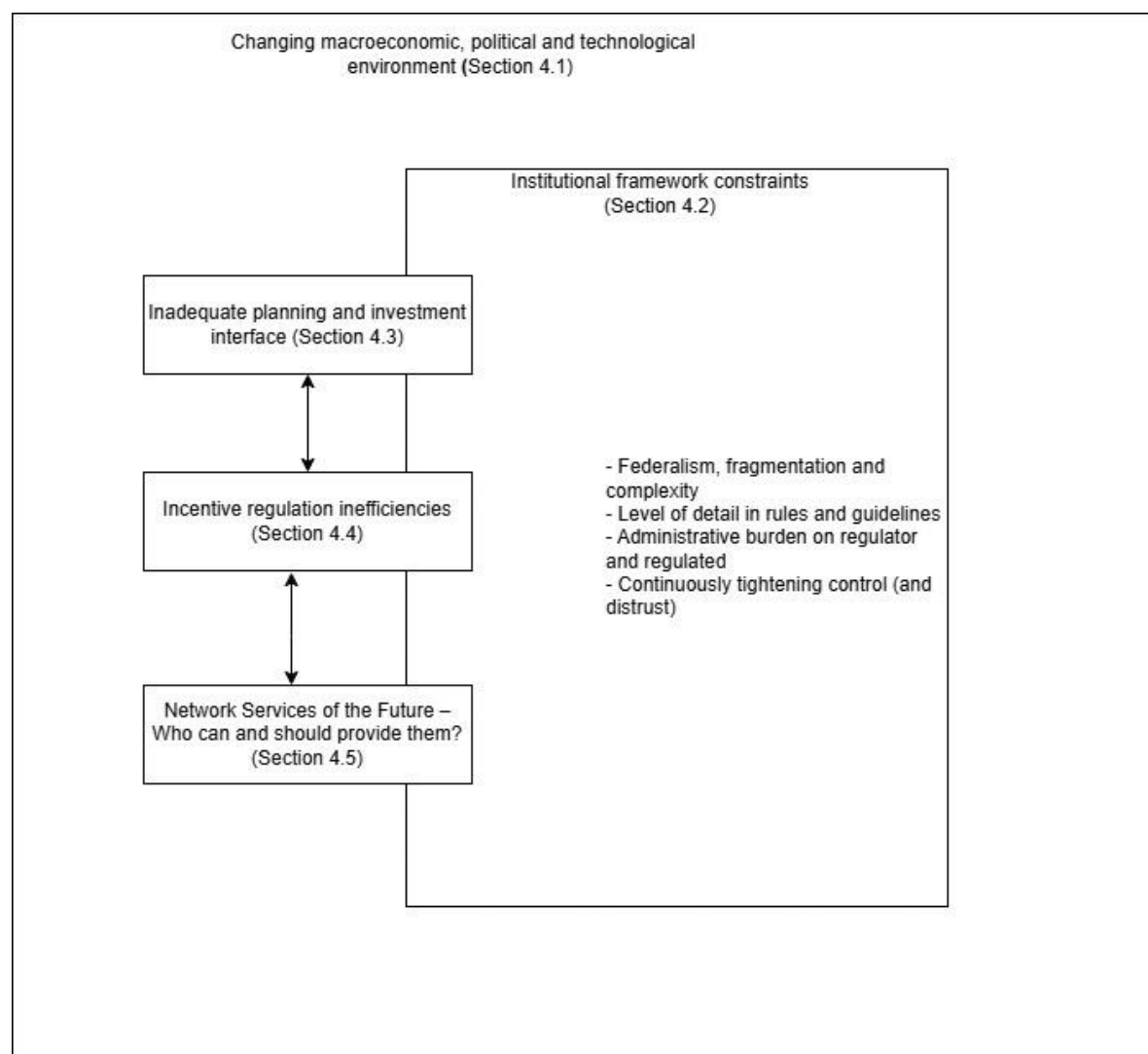


Figure 6: Network investment regulation – areas of improvement in context.

Traditionally, network investment has been defined as expenditure required to meet regulatory obligations imposed on network service providers, particularly the provision of safe, reliable, and secure electricity services (see Section 3.1 for details). As electricity supply constitutes an essential service - “one the stoppage of which inflicts hardship upon the community” (House of Commons, 1927, p. 1120) - ongoing investment in the maintenance, replacement, and expansion of network infrastructure is indispensable. The scope of these investments is increasingly shaped by broader policy objectives, including those embedded in the National Electricity Objective (NEO), which emphasises not only reliability and security but also emissions reductions and the long-term interests of consumers. Thus, a key question surrounding regulation is *whether current regulatory frameworks merely sustain existing network functions, or whether they are adequately designed to enable and support the broader energy transition?*

Figure 6 provides an overview of the broader ecosystem of network investment regulatory framework and its interaction with the macroeconomic, technological and policy environment. Within the broader environment and the boundaries set by framework design itself – we discuss three main areas of challenges that may render network investment regulatory frameworks unfit for purpose. These areas cover long-term planning, incentive regulation and the question of how to integrate non-network solutions and 3rd party providers into a framework designed for regulated monopolies.

The novelty of our study lies in its focus on regulatory design, and the identification of regulatory gaps and contradicting aims associated with Australia’s energy transitions pressures.

The next subsections detail the key aspects of the identified regulatory challenges.

4.1 External drivers: Changing macroeconomic, political and technological Environment

Over the past two decades, electricity networks have faced unprecedented challenges that fundamentally alter both the type and scale of required investment. State and federal energy policies (Csereklyei and Say, 2026) alongside technological development and lower capital costs have driven significant integration of utility-scale renewable generation, with the share of non-hydro renewables in the NEM rising from 2.2 % in 2010 to 37.1 % in 2025. (OpenElectricity, 2026)

The simultaneous rapid uptake of distributed energy resources - including rooftop solar, battery storage, and other forms of embedded generation – has also transformed many consumers into prosumers, introducing increasingly complex, two-way power flows across distribution networks, as well as major changes in intraday demand patterns, in particular in minimum operational demand. These changes increasingly create voltage management difficulties and hurdles to continued distributed generation integration. (Jemena Electricity Networks, 2026).

Emerging sources of demand, particularly electrification in industry and residential sectors as well as the emergence of data centres, are expected to contribute to significant increases in maximum demand. As a result, both maximum and minimum demand levels are anticipated to exhibit larger variation, resulting in increased volatility and operational complexity, putting a strain on network services and utilisation levels. This has flow-on-effects for network investment, as networks increasingly have to invest in assets and software to provide for grid security and stability.

Key regulatory responses to perceived challenges included for example the introduction of different incentive mechanisms for network innovation (AEMC, 2015a), the introduction of an Integrated Resource Provider to easier integrate technologies such as storage into the system (AEMC, 2021), or the introduction of the demand side register (AEMC, 2015b). Recently, the AEMC has introduced a rule change to the distribution network planning and reporting processes (AEMC, 2026a), which we will discuss in Section 4.3.

Despite these activities, we argue that “reform by rule change” is inherently piecemeal and bears a risk of lacking holistic assessment of the challenges the rapid change in the energy sector poses. Given the high level of complexity of the regulatory framework, incremental change of the rules can lead to the creation of increasingly complicated requirements for regulators and networks, making the resulting framework difficult for consumers and other stakeholders to comprehend. We will set out the challenges identified in the NEM framework in detail below, starting with institutional framework constraints in 4.2, the (lack of) integration between physical and economic planning in 4.3, inefficiencies in incentive regulations in 4.4, and the regulation of non-network activities and third-party engagement in 4.5.

Despite the repeated corrective actions of the rule maker, we pose that a fundamental rethinking of whether the regulatory framework is achieving its purposes would be timely.

4.2 Institutional framework constraints

The regulatory frameworks for distribution network investment, and for the NEM more generally, were and still are overall designed for a different technological base case - that of stable supply and demand, passive consumers, and steady one-way flow of electricity from generation to end-users. A central question of our report is whether regulatory settings are or are not keeping up with the technological and macroeconomic changes.

A *regulatory lag* (sometimes called the pacing problem) refers to the tendency of law, regulation, and governance institutions to adapt more slowly than technological innovation (Bennett Moses, 2007, 2017; Ahern, 2025). As new technologies emerge, existing legal frameworks may not adequately address their risks, benefits, or social consequences, creating periods of uncertainty and regulatory gaps. This lag exists for several reasons. Bennett Moses (2017) identifies centrally that law is built around existing practices and assumptions. Legal

processes need to be re-evaluated, when such assumptions and practices change, which can be a drawn-out process.

In addition, infrastructure sectors, such as the energy sector, are prone to *path dependency* and *regulatory lock in*. The electricity system can be viewed as a socio-technical system, with law and regulation as one of several elements in this system, alongside technology, as well as values and norms informing the system (Künneke and Groenewegen, 2009; Mitchell and Woodman, 2010).

Elements in the system interact with each other, influencing the opportunities for change; a dynamic which can result in lock-in and path dependence (Arthur, 1989; David, 2000; Unruh, 2000). This lock-in of old patterns of how we generate, transport and use electricity, can at the same time *lock-out* new technologies, because they do not easily fit into a system that has developed to suit very different conditions (del Rio and Unruh 2007). Regulatory change in socio-technical systems is often incremental and constrained by the initial design settings of the framework.

The final challenge for network regulation is inherent in the design of a liberalised electricity market with regulated networks. The core purpose of the network investment regulatory framework is to regulate the (economic) behaviour of firms providing an essential service. As such the regulator can be assumed to seek societal welfare maximisation. It is however hindered in its task due to information asymmetry between the regulator and the regulated firm (in this case the distribution network) (Joskow, 2014). One of the key functions of regulatory design (incentive regulation) thus is to mitigate this information asymmetry.

The challenges arising from the regulatory lag, path dependencies, and information asymmetries in a fast-changing environment – are exacerbated by the institutional design of the NEM.

4.2.1 The institutional design of the NEM and its challenges

A key question we ask is how does the way in which the current regulatory framework sets out different roles and responsibilities (networks, regulators, policy makers) in the investment process impact on the ability to flexibly transition networks?

As noted by previous studies, the current NEM frameworks are slow to react to change and emphasise piecemeal adjustments of particular rules (Csereklyei and Kallies, 2024; PIAC, 2015). This incrementalism is fundamentally due to regulatory design.

The AEMC, as primary rule maker is tasked with writing the rules and subsequent changes to them. The AEMC however, is not in the position to propose rule changes outside of the narrow

scope of NEL s 91 (2).³⁰ In addition to evaluating rule changes, the AEMC can initiate market reviews (NEL s 45) or these can be requested by the Ministerial Council (NEL s 41), which body can make recommendations for policy change. These changes, however, will require rule change requests. Rule change requests in general rely on applications by stakeholders— often informed by the particular interest of the requesting party. Challenges are met with individual rule changes in a reactive, rather than proactive way.

Neither of these mechanisms – the review process or the rule change mechanism - are designed for comprehensive rethinking of whether and how the regulatory framework is suited for a future electricity system.

As policy maker, it is the role of the Ministerial Council to drive fundamental changes of the regulatory framework. The Council is responsible for strategic future directions of the NEM and addressing longer-term systemic and structural issues (AEMA, 2004). The Council can, for example, issue statements of policy principles to the AEMC, which must be considered during a rule change process or review conduct (NEL s8). This mechanism is however not often employed. The Council’s consensus-based federalist structure can also generate governance gaps, policy delays, and investment uncertainty. This strategic policy deficit inherent in the design of the NEM governance frameworks has long been described (Vertigan, Yarrow and Morton, 2015; Crossley 2024; Kallies 2016). Jurisdiction-level policy-making and derogations from the shared NEM governance framework can be seen as reaction to this deficit (Kallies, 2021).

As a result, in addition to the multiple rule changes, we have seen states increasingly derogating from the common rule framework – a situation that leads to further complexity and fragmentation of the NEM framework. We acknowledge this as an overarching issue for supporting meaningful change in the NEM frameworks. Network investment processes embody this institutional complexity. Here, the complexity is added to, through multiple guidelines made by the AER, expanding on the requirements of an already detailed rule framework. Increasingly fine-grained information is required from networks in regard to both network planning and the revenue proposals, as well as multiple checks and steps for a revenue proposal to be approved. A plethora of AER guidelines were issued to expand the already detailed requirements of the rules (see Section 3 and Appendix 2).

While detailed requirements set out in the NER and guidelines are intended to safeguard consumers, they signal an assumption that networks will not act in the interest of social welfare without close supervision. This dynamic has resulted in compliance obligations that have become resource-intensive and in slow decision-making processes, potentially discouraging

³⁰ NEL s91 (2) which provides that “The AEMC must not make a Rule without a request under subsection (1) unless - (a) it considers the Rule corrects a minor error in the Rules; or (b) it considers the Rule involves a non-material change to the Rules; or (c) the Rule is in respect of any matter that is prescribed by the Regulations as a matter on which it may make a Rule on its own initiative”.

innovation and adaptive investment (Ben-David, 2026). Ben-David (2026, p5) speaks of “economic regulation as an ‘arms race’ between network operators and the regulator”, which comes with significant administrative burdens on both the regulator and the regulated firm (Kuiper, 2024).

Two very recent developments (in 2026) represent a regulatory attempt of undertaking a broader review of network regulatory processes: the AEMC’s Electricity Network Regulation Review Part 1 and 2 (AEMC 2026b & 2026c) and the AER’s companion Future of Electricity Network Regulation information paper (AER 2026b). Both remain live consultations at the time of writing.

4.3. Inadequate planning and investment interface

As described in Section 3.2, physical network planning is undertaken under Chapter 5 of the NER. Chapter 5 regulations set out what assets can be invested in and on what terms. Physical network planning is currently undertaken on an annual basis with a rolling window of minimum 5, often 10 or more years. As set out in Section 3.2, this will change to 5-yearly DNDP with a 20-year horizon with annual updates.

Whether these investment plans can be carried out and reimbursed, is determined through the economic forecasting and investment approvals framework under Chapter 6 of the NER, which currently limits forecasting to 5 years ahead. Thus, while the frequency of the DNDP has been adapted, there are still different levels of information and time horizons (long vs. medium) required and acted upon in the two processes.

The first major issue we identify here is the lack of harmonisation (coordination) between the (long term) investment planning and the economic forecasting processes. This is particularly evident in the lack of long-term economic forecast processes and the ability of networks to commit to long-term, strategic investment (over 5 years of scope), even if it would be in the interest of the consumers.

The final rule³¹ requires DNSPs to plan over a longer (20-year) horizon and replaces annual DAPR with a Distribution Network Development Plan (DNDP) to be developed every 5 years (with annual updates). It also introduces changes aimed at more transparency in network planning, and better stakeholder engagement. From December 2027, NER 5.13.1 will expressly require a DNSP to submit the new DNDP “at the same time that it is required to submit a regulatory proposal under clause 6.8.2, submit a plan for the development of its distribution network to the AER and publish the plan on its website.” In turn, the new NER 6.8.2 (c4) will require the DNDP to be submitted with the regulatory proposal. This, in turn, will require the

³¹ The proposed changes will commence on 1 December 2027. See AEMC (2026a) National Electricity Amendment (Enhancing distribution network planning and reporting) Rule 2026 No. 7.

AER “to have regard to” the DNDP, as it becomes part of the “information submitted” with the regulatory proposal (NER 6.10.1(b)).

The rule change does not, however, introduce any further changes to Chapter 6 for distribution network regulation and leaves economic forecasting and revenue determination with a 5-year horizon processes unchanged. The DNDP cannot be relied upon as part of the proposal.³² There remains a timeframe gap between translating the long-term physical planning outputs into the economic forecast, which may lead to actual investment decisions that are suboptimal in the long run.

In other words, while the AEMC rule change addresses the physical planning side, it is silent on whether and how these long-term plans translate into the forecasting/regulatory approval processes set out in Chapter 6, beyond a commitment to submit the DNDP as part of the networks submission of the regulatory proposal. We suggest that while longer timeframes for network planning are a welcome development, their interaction with the investment processes should be carefully considered and expressly incorporated into the legislative framework. Below we identify a number of challenges arising predominantly from the current lack of coordination and connectivity between network planning and investment forecasting and determination processes, and other parts of investment regulation:

4.3.1. Lack of anticipatory investment

The traditional 5-year economic forecast process has become increasingly uncertain and contested (AER, 2025c; Kuiper, 2024), due to the rapid pace of change in the energy environment.

The current framework relies heavily on detailed ex ante planning, despite significant uncertainty, which also extends to decisions about network sizing in new developments, where it is difficult to anticipate future scenarios such as widespread electric vehicle adoption or universal deployment of solar and batteries. The length of the regulatory period associated with economic forecasts (5 years) thus has to come under scrutiny. Firstly, given the level of prescriptiveness and detail required by the regulator at the proposal stage, particularly in light of uncertainty and environmental changes, the current regulatory period length might appear too long (see Section 4.3.2). However, in terms of facilitating anticipatory and transition enabling investments, the 5-year period might be considered too short and inflexible, potentially leading to a suboptimal investment outcomes from a societal point of view.

The problem thus is two-fold here. First, we identify a lack of long-term “transition enabling investments”, which cause a “horizon problem” where networks are forced to invest with a mid-term horizon, and potentially carry out piecemeal adjustments. The alignment of timing of

³² This was suggested and expressly rejected by the AEMC in the rule determination, AEMC (2026d).

the frequency (5 yearly) and submission timing of the Chapter 5 DNDP and the Chapter 6 regulatory proposals does not address the longer horizon issue. While the new DNDP has a time horizon of 20 years, regulatory proposals remain at a 5 year horizon. Second, we identify an issue with the difficulty networks encounter in changing or deviating from the current mid-term forecasts, which we call the “level of detail problem”.

As described in Section 3, mechanisms to adjust “current” forecasts within a regulatory period are complex, detailed and carry a heavy administrative burden. While it is possible to respond to unforeseen developments reactively, proactive or anticipatory investment opportunities are limited. Mechanisms for revising forecasts are also complex and limited to particular situations (see in detail Section 3.3.4).

Distribution networks face significant difficulties investing ahead of demand because regulatory constraints discourage oversizing or forward-looking infrastructure development, with the goal of keeping “affordability”, thus ensuring that any investments are required for the prudent and efficient operation of networks. As a result, investment tends to occur incrementally. This raises the question of whether the long-term cost of incremental upgrades may exceed the cost of larger, anticipatory investments undertaken earlier, and result in a loss of net economic benefit to consumers in the long run. It also raises questions about the allocation of risk, in an environment where the risk of overinvestment is already largely borne by consumers.

The first question here is how to make investment (and their permitting) more flexible, while retaining prudence and efficiency. The second question is how to integrate the long term (10-20-year) planning into the economic forecasting and revenue proposal process, where it is enabling future investment or investment that might carry a higher societal value.

Our second report in this project (Cserekyei and Kallies, 2026) provides a look at other jurisdictions for anticipatory or flexibility enabling planning horizons.

This tension between forecast horizons and anticipatory investment is currently a live line of inquiry: the AEMC’s 2026 Package 2 review identifies rising demand-forecast risk - driven by large discrete loads such as data centres, accelerating electrification, and jurisdictional policy divergence - as a key pressure on the current five-year framework (AEMC, 2026c).

4.3.2 Level of prescriptiveness in economic forecast and revenue determinations and the interaction with network planning and the RIT-D

Chapter 6 of the regulatory framework places a high degree of emphasis on detailed and prescriptive economic forecasts. Given the time-horizon of the forecasting process, networks must begin estimating their required investment needs well ahead of the 5-year regulatory period, which the forecast relates to. As a result, highly detailed predictions are often required 6-7 years or more prior to the actual investment being anticipated. Following the determination by the AER, the forecast becomes a binding constraint (see Figure 1), which is

difficult to deviate from. These are in addition to the annual planning requirements of the DAPR and the future DNDP and its annual updates (see above Section 3.2). If the cost threshold is met, specific capital investment proposals will have to go through the RIT-D process with detailed assessments, requiring potentially a reassessment of a proposal with associated administrative burden for regulator and network.

Given the pace of technological progress and the unexpectedness of economic policy driving energy market outcomes (Csereklyei and Kallies, 2024), this level of prescription at the forecasting stage might appear impractical. This raises the fundamental question *whether forecasting requirements should be less prescriptive and whether a partial shift towards ex post assessment might provide greater flexibility?* In addition, we query *to what degree duplications in the assessment of specific projects across physical planning, economic forecasting and RIT-D assessment can be streamlined and what the best point in time is to assess the net economic benefit of investment decisions?*

The reason for the detailed forecasts and tight control through the RIT-D cost-benefit analysis process is the goal of the regulator in safeguarding consumer interest. Given the current framework setting and the tendency to regulate to the smallest detail, this process requires enormous administrative efforts both from the regulator and from the networks. As described in Section 4.2, regulators face information asymmetry vis a vis networks. In the absence of better regulatory solutions, the regulator will try to address this asymmetry by requiring detailed information from networks.

Reducing ex ante information requirements could in theory and in practice create opportunities for networks to exploit regulatory gaps. Ben-David (2026) notes in fact that the gap between network draft investment forecasts and the authorised capital expenditure allowances has been continuously increasing in the past years, as opposed to decreasing. He links this disparity to the fact that the regulatory framework is created on the assumption that “the regulator must play a countervailing role to the network operators” (Ben-David, 2026: p. 10).

We recommend examining whether and how networks can be given greater flexibility, while also ensuring they act in the long-term interests of consumers.

4.3.3 Lack of alignment of distribution planning with AEMO (ISP) scenarios

The AEMC’s directions paper for the network planning rule change (AEMC, 2025b) raised the current lack of alignment between the annual planning process of the networks and AEMO’s Integrated System Plan or other network planning processes. At the moment, distribution network planning is required to be coordinated with the transmission networks they are connecting to (NER 5.14), but distribution networks are currently not expressly required to adhere to their planning with the ISP scenarios of AEMO. The AEMC poses that this lack of coordination creates risks of misalignment, leading to inefficiencies and potentially higher costs

(AEMC, 2025b). The now passed final rule change is seeking to address this gap by requiring DNSP's to adopt "to the extent practicable" AEMO's Inputs, Assumptions and Scenarios Report (IASR) when preparing the Distribution Network Development Plan (new NER 5.13.1(d)). This report also provides the assumptions and scenarios feeding into AEMO's ISP.

A recent example shows that relying on system-level projections is not necessarily considered sufficient for AER determinations. Jemena's initial revenue proposal for the 2026-2031 revenue period relied heavily on ISP projections. The AER did not accept forecasts across CAPEX, OPEX and REPEX, because they were not sufficiently substantiated – and considered it "was unclear how the local-level forecast reconciles with the system-level forecast" (AER, 2025d, p 20).

This suggestion however poses the question of *whether AEMO's IASR projections are sufficiently concrete and reliable for distribution networks to align their planning with. Secondly, if networks base their economic forecasting on these projections who carries the responsibility for major forecasting error?*

Expressly linking distribution system planning into overall system planning without creating effective coordination pathways has the potential to create uncertainty and to reduce the effectiveness of coordinated system-wide planning.

The concept of emissions reduction has been incorporated both in NER Chapters 5 and 6.

As set out in 3.3 above, the definition of the Net Economic Benefit (NEB) has been expanded with the addition of the requirement to consider "*the net economic benefit of changes to Australia's greenhouse gas emissions, whether or not that net benefit is to those who produce, consume or transport electricity in the NEM.*" The NEB is the central cornerstone for assessing the utility of individual investments under the RIT-D.

In addition, the forecasting and revenue determination process, the new emissions reduction objective has been added to NER 6.5.7 (a)(5), to be expressly included in the building block approach.

(a) A building block proposal must include the total forecast capital expenditure for the relevant regulatory control period which the Distribution Network Service Provider considers is required in order to do each of the following (the capital expenditure objectives):

...

(5) contribute to achieving emissions reduction targets through the supply of standard control services.

4.3.4 Valuing emissions reductions in the RIT process

Lastly, we address a topic associated with the RIT process, namely changes in determining the net economic benefit of a project, after a sweeping regulatory change incorporated emissions reductions into the national frameworks.

As set out in 2.3 of this report, the National Electricity Objective was amended in 2023 to incorporate Australia's commitment to reduction in greenhouse gas emission, resulting in the retrofitting of the NER, including the sections on network investments. Central to these changes has been the definition of the Net Economic Benefit (NEB).

This new requirement to evaluate the emissions reductions outcome of a new proposed investment changes project economics, justified partly on the basis of avoided carbon intensity, or renewable congestion relief *compared to a base case*.

While the rules have been amended and expanded on the conceptual scope of allowable benefits, they remain vague. Much of the practical implementation has been pushed into AER guidelines, modelling assumptions and discretionary judgement within cost-benefit analysis frameworks, in lieu of precise regulatory phrasing. Currently the AER has a number of documents in place that provide detail on how emissions reductions can be accounted for.

- the RIT-D guideline (AER, 2024b)
- A guidance document of valuing emissions reductions (AER, 2024c), and
- more specifically for economic forecasting, an interim guidance note on emissions reductions (AER, 2025e)

Thus, potential emissions reductions are assessed in the investment process as: (i) part of the RIT-D process, and (ii) as part of the building block approach.

Even though detailed guidelines exist, fundamental questions remain in regard to how “avoided emissions” should actually be measured and causation argued, including whether emissions are assessed on a marginal or average basis, how changing generation mix assumptions should be treated over time, and how indirect benefits such as accelerated electrification or avoided future network augmentation should be attributed. Ambiguity may also exist in how to value hosting capacity and export flexibility, where system-wide benefits may accrue unevenly across time and customer classes. These changes - in theory - alter distribution network's planning incentives, non-network procurement viability, and investment logic. They also increase regulatory uncertainty around how transition-related benefits are to be evidenced and defended within expenditure assessments.

The difficulty of this task lies again in the level of detail and assumptions required for both the base case and the investment. For example, a suburban feeder augmentation, flexible export

upgrade or EV hosting investment may not have a directly observable emissions outcome. The investment may enable more rooftop solar exports, electrification uptake or DER participation, but the causal chain between the network asset and actual emissions reduction is highly uncertain. It remains open to determine:

- would customers have installed solar or EVs anyway?
- would exports simply displace other renewables rather than fossil generation?
- which marginal generator is assumed to be displaced?
- over what timeframe?
- under which demand and DER uptake scenario?
- how should rebound effects or induced demand be treated?

Thus, the case of amending regulation to include emissions reduction presents another case of piecemeal regulation – the operationalisation of the emissions reduction objective has largely been left to AER guidance. The implementation of how exactly the emissions reduction objective can be implemented, was mostly left to networks and the AER to negotiate, *without a sufficiently clear outcome for networks*.

4.4 Incentive regulation inefficiencies

As described in Section 2, the regulator’s fundamental aim is the maximisation of consumer welfare through affordable end-user prices and high service quality, while making sure that the regulated network has the opportunity to maintain normal profits (Brown and Sappington, 2025).

The regulator’s ability to fulfil these aims is constrained by incomplete and asymmetric information about the regulated firm’s costs, its opportunities to improve service quality, and the characteristics of the demand it serves (Joskow, 2014). While repeated regulatory interactions may gradually reduce these informational asymmetries, they remain an intrinsic feature of the regulatory process (Joskow, 2014; Laffont and Tirole, 1993).

Informational asymmetries create opportunities for regulated firms to use their informational advantage strategically to increase profits or pursue managerial objectives that may not align with consumers’ interests (Joskow, 2014; Owen and Braeutigam, 1978; Laffont and Tirole, 1993). These agency problems may be further compounded if regulatory capture occurs, leading the regulator to place greater weight on the firm’s interests than on those of consumers or the broader public (Posner, 1974; Spiller, 1990; Laffont and Tirole, 1993, Joskow, 2014). Furthermore, a firm’s costs depend not only on its structural opportunities but also on managerial decisions to exploit those opportunities (Joskow, 2014), introducing both moral hazard and adverse selection into the regulator’s decision problem.

Different forms of incentive regulation have been introduced by regulators internationally, with the main purpose of enabling the regulator to overcome information asymmetry (including adverse selection and moral hazard) while promoting consumer interests (Joskow, 2014; McHarg, 2011; Joskow and Schmalensee, 1986). The objectives of incentive regulation are severalfold, even though the specific form of incentive regulation or policy architecture may vary widely across jurisdictions (Kuiper, 2024). Brown and Sappington (2025) note that, to achieve their goals, regulators often enable at least a limited period of enhanced profits for regulated firms, while facing pressure for low prices from consumers. Excessive penalties are known to result in underinvestment in capital; to avoid this, the design of policy instruments must be carefully considered.

4.4.1 Types of incentive regulation

The two principal approaches to network regulatory design are (i) cost-of-service regulation (COSR) and (ii) incentive regulation, which may include a price cap (PCR) or revenue cap (RCR) model. This dichotomy is increasingly understood as describing the poles of a spectrum rather than a clean binary: RPI-X/price-cap regulation for network utilities has itself been characterised as an important variant of COSR rather than a true alternative to it, given its reliance on periodic true-up mechanisms (Joskow and Schmalensee, 2025), and most real-world systems - including Australia's building-block model - combine elements of both.

Under COSR, regulated prices are established to reflect realised costs, ensuring that the regulated firm earns no more than a normal return (Brown and Sappington, 2025; Joskow and Schmalensee, 1986). While this approach provides protection against excessive profitability, it provides limited incentives for cost efficiency, because firms are compensated for their realised costs. This may be particularly problematic where privately owned, profit-maximising firms have incentives to prioritise shareholder returns over consumer interests. Even publicly owned network businesses may pursue organisational or policy objectives that do not necessarily align fully with consumer welfare (Brown and Sappington, 2025).

Many jurisdictions, including Australia, have therefore adopted incentive regulation as a means of strengthening incentives for cost reduction, most commonly in the form of either a price cap or a revenue cap. Under a theoretical PCR scenario, regulated prices are expected to be established with reference to estimates of the prices that would prevail under competitive market conditions, rather than the firm's realised costs. In exchange for delivering an initial benefit to consumers through lower regulated prices, firms are permitted to retain the gains from subsequent cost reductions during the regulatory period, since prices are not automatically ratcheted downward to reflect realised efficiency improvements (Brown and Sappington, 2025)³³.

³³ Where regulators have limited information about the competitive prices that should inform PCR design, Brown and Sappington (2025) identify earnings sharing regulation (ESR) as an alternative approach. ESR retains the

Under revenue cap regulation theory, it is the network's total allowed revenue, rather than the price per unit, that the regulator fixes for the regulatory period; the price charged to consumers is then derived residually from that revenue target and the forecast volume of electricity delivered (Kuiper, 2024; McHarg, 2011). Because realised volumes will not exactly match the volumes forecast when the cap was set, most revenue cap schemes include a true-up mechanism that adjusts prices in a subsequent period to correct for any shortfall or surplus against the allowed revenue target.

Joskow (2014) highlights that alternative regulatory arrangements represent different responses to the information problems inherent in regulation. Fixed-price incentive mechanisms such as PCR for example, address the moral hazard problem by placing stronger incentives on firms to control costs; however, because regulators have imperfect information about firms' underlying cost conditions, such mechanisms leave regulators vulnerable to adverse selection. Conversely, COSR mitigates adverse selection by guaranteeing recovery of realised production costs, but at the expense of weaker incentives for cost minimisation, leaving fuller exposure to moral hazard (Joskow, 2014).

Within incentive regulation, price cap and revenue cap regulation are not exhaustive alternatives but represent one specific design: how the regulatory cap is denominated, and consequently how demand/volume risk is allocated between the firm and consumers. Price cap regulation fixes the price per unit, leaving the firm to bear volume risk; revenue cap regulation fixes total allowed revenue, shifting volume risk toward consumers via a true-up mechanism (Kuiper, 2024; McHarg, 2011; Csereklyei and Kallies, 2026)³⁴. The Netherlands perhaps was a good example of price cap regulation in its pure form until recently; Australia³⁵ and Great Britain instead operate variants of revenue cap regulation (Kuiper, 2024; for detailed comparison see Csereklyei and Kallies, 2026).

Several economists have argued that a one-size-fits-all regulatory design may not always generate the most efficient outcome, and that offering regulated firms a menu of regulatory options may produce superior welfare outcomes (Joskow, 2014; Brown and Sappington, 2025). In theory, a regulatory menu of options, or sliding-scale approach (Joskow, 2014), allows the regulated firm to select from a range of regulatory contracts, drawing on its superior knowledge of its own operational conditions and cost structure. By allowing firms to self-select a preferred

basic features of PCR but requires regulated firms to share a proportion of realised earnings above, and potentially below, specified thresholds with consumers. By sharing the benefits of efficiency improvements between firms and consumers, ESR provides a compromise between the stronger incentive properties of PCR and the lower-powered incentives associated with COSR, although it provides weaker incentives for cost reduction than PCR (Brown and Sappington, 2025).

³⁴ This is a separate dimension from other features of incentive-regulation design - such as benchmarking/yardstick competition, menu regulation, and sharing mechanisms - which vary independently of whether a jurisdiction uses a price cap or a revenue cap (Csereklyei and Kallies, 2026).

³⁵ By comparison gas networks classified as scheme pipelines continue to operate under price-cap regulation (see for example AER; 2025g).

regulatory arrangement, the mechanism can use this private information to improve regulatory outcomes.³⁶

The availability of such a menu ensures that regulated firms retain an option consistent with their break-even constraint (Brown and Sappington, 2025). Although such an approach introduces additional regulatory complexity, it may allow regulators to better accommodate differences in firms' cost conditions and information advantages.³⁷

In practice, menu-based regulatory approaches remain rare. Ofgem initially introduced an Information Quality Incentive (IQI) into its 2005–2010 Distribution Price Control Review, offering network companies a menu of expenditure allowance and incentive-rate combinations constructed so that a company's own best interest was served by revealing its true expenditure forecast (Ofgem, 2004, Frontier Economics, 2017, McHarg 2011).

This mechanism was subsequently moved away from and evolved into a TOTEX-based approach under Ofgem's RIIO (Revenue = Incentives + Innovation + Outputs) framework. RIIO retains the *ex ante*, incentive-based structure of its RPI-X predecessor, but assesses capital and operating expenditure together as a single TOTEX allowance, applies a common efficiency rate to remove the incentive to reclassify costs between CAPEX and OPEX, and pairs this with an output-led framework spanning six categories of service outcome (McHarg, 2011). While RIIO no longer allows companies to select a scheme from a contractual menu, it still leaves companies some freedom in how they deliver agreed outputs most efficiently.³⁸

4.4.2 The objectives of incentive regulation

Incentive regulation has several objectives: securing low prices for consumers, efficient levels of service quality, efficient levels of capital investment, the promotion of non-network solutions and distributed energy resources (DER), and the pursuit of environmental goals (Brown and Sappington, 2025).

Service quality considerations are usually incorporated into incentive schemes through a range of regulatory mechanisms. Regulators may specify (i) minimum quality standards, (ii) financial penalties when realised quality falls below these standards, and (iii) financial rewards when performance exceeds them. Ideally, these penalties and rewards should reflect the

³⁶ As described by Joskow (2014), sliding-scale mechanisms can take the form of profit-sharing arrangements or hybrid regulatory schemes in which regulated prices respond partially to realised costs while remaining partially fixed *ex ante* (Schmalensee, 1989; Lyon, 1996).

³⁷ Other factors influencing firms' behaviour and the efficacy of regulation include the length of the regulatory period and the possibility of reopeners and alternative rate structures.

³⁸ By the 2018 RIIO-2 framework consultation Ofgem was openly questioning whether the IQI had worked: companies had "generally spent well below what they forecasted," so the menu was not delivering the accurate forecasts it was meant to elicit (Ofgem, 2018).

corresponding costs and benefits experienced by consumers from changes in service quality (Brown and Sappington, 2025).³⁹

In Australia, service quality incentives for distribution networks are defined under NER clause 6.6.2, which requires the AER to develop and publish one or more service target performance incentive schemes to reward or penalise Distribution Network Service Providers (DNSPs) for maintaining or improving performance. In designing such a scheme, the AER must consult with the authorities responsible for jurisdictional electricity legislation, and must ensure that any service standards or targets it sets do not put a DNSP's compliance with jurisdictional service standards at risk, since a service target performance incentive scheme operates concurrently with jurisdictional service standard and guaranteed service level regimes rather than displacing them. The AER must also take into account whether the likely consumer benefit of the scheme justifies the reward or penalty involved, the DNSP's past performance and existing regulatory obligations, any other incentives the DNSP already faces under the Rules, the need to ensure incentives are strong enough to offset any financial incentive to cut costs at the expense of service, and the possible effects of the scheme on incentives to adopt non-network or stand-alone power system (SAPS) options. The AER may amend or replace a scheme from time to time, and a DNSP may pass the benefits (or liabilities) of the scheme through to a third-party network support provider by contract (NER cl.6.6.2). Service quality requirements enter the revenue determination process under NER clause 6.8.2, when the AER incorporates them into the framework and approach paper applying to the forthcoming regulatory period.

Another key objective of incentive regulation is to ensure efficient capital investment. Brown and Sappington (2025) note that regulators may be inclined to guarantee returns on investments required for firms to satisfy their break-even constraints, but such guarantees may create incentives for regulated firms to overstate the efficient level of capital investment. The main incentive scheme available to Australian distribution networks for this purpose is the Capital Expenditure Sharing Scheme, discussed in detail in Section 4.4.3 below.

Regulators may also seek to promote DER uptake and non-network solutions through changes to the baseline regulatory framework, as illustrated by Ofgem (for details see Csereklyei and Kallies 2026). Ofgem's move towards the RIIO and the introduction of TOTEX, sought to avoid incentives favouring capital expenditure over operational alternatives, by setting a revenue requirement that reflects the efficient and prudent cost a network would incur when employing an efficient mix of both capital and non-capital solutions (Brown and Sappington, 2025; Frontier Economics, 2017). The next sub-section explores incentive regulation in Australia in detail.

³⁹“The efficient level of a particular dimension of service quality (e.g., system reliability) is the level that maximizes the difference between the benefits generated by the quality and the costs of delivering the quality. In practice, a regulator seldom has the information required to precisely identify efficient levels of service quality in the jurisdiction it oversees” (Brown and Sappington, 2025, p.27).

4.4.3 Incentive regulation in Australia

Network incentive regulation in Australia, while originally based on the UK's initial RPI-X framework, has evolved differently from its British counterpart, both in the level of detail required in forecasts and in the types of incentive structures offered. Incentive regulation for DNSPs in Australia originates from the early development of the National Electricity Market in the late 1990s and was progressively embedded into the National Electricity Rules through the early 2000s reform period, before being consolidated and materially strengthened with the establishment of the Australian Energy Regulator in 2005, which brought a more formalised, rules-based system of revenue determination and performance incentives for distribution businesses. The current incentive framework is thus built on assumptions originally designed for a system focused on meeting peak demand growth, rather than on managing demand, and is now operating under structurally different conditions driven by electrification, DER uptake and broader transition uncertainty. Australia's building-block model is best understood as a hybrid design: a rate-of-return, RAB-based cost architecture (see Section 3.3.2 above) combined with a revenue-cap incentive-regulation classification. The AER however retains discretion to "apply either a revenue cap or a price cap, and in recent determinations has consistently chosen to apply a revenue cap" (AEMC, 2026c, NER cl. 6.2.5).

Overall, while the consensus remains that the current incentive framework is broadly effective in delivering efficiency outcomes, regulatory and academic reviews indicate growing concern about its fitness for purpose in a transitioning system.

The question this section asks is: are Australia's DNSP incentive schemes harmonised to pursue balanced goals – enabling adequate and efficient long-run investment and operation, high quality of service, and cutting-edge innovation – in a way that aligns with the National Electricity Objective in a transitioning electricity system characterised by electrification, DER uptake and decarbonisation policy constraints?

The main incentive schemes applicable to distribution networks under Chapter 6 of the National Electricity Rules are the Efficiency Benefit Sharing Scheme (EBSS), the Capital Expenditure Sharing Scheme (CESS), the Service Target Performance Incentive Scheme (STPIS), the Customer Service Incentive Scheme (CSIS) and the Demand Management Incentive Scheme (DMIS). In addition, the Demand Management Innovation Allowance Mechanism (DMIAM) operates as a complementary funding mechanism supporting DNSPs' research and development of innovative demand-side or non-network solutions. In theory, these schemes are together designed to reward cost efficiency, improve service performance, and encourage DNSPs to pursue non-network alternatives where these are more efficient than traditional network investment.

The legal purpose of these schemes is not defined as a standalone objective for “incentive regulation” in the Rules themselves but instead flows from Section 7 of the National Electricity Law, the National Electricity Objective, and the Revenue and Pricing Principles in section 7A. These provisions require regulation to promote efficient investment in, and efficient operation and use of, electricity services in the long-term interests of consumers with respect to price, quality, safety, reliability, security of supply and emissions reductions. The DNSP incentive schemes are the practical mechanism through which this efficiency objective is implemented in revenue determinations and operational behaviour.

In practice, however, some schemes are far more extensively utilised than others, and interactions between different incentive schemes further complicate their effectiveness. The current Australian framework, and in particular the CESS – one of most utilised of these schemes⁴⁰, alongside the presence of a separate EBSS – has been criticised for incentivising capital expenditure over operating expenditure and non-network solutions (or non-wires alternatives) such as demand management, potentially leading to inefficient outcomes (Kuiper, 2024; Frontier Economics, 2017). This is consistent with the theoretical capital bias identified in the wider regulatory economics literature: the classical Averch-Johnson (1962) result that rate-of-return regulation increases capital intensity where the allowed return exceeds the true cost of capital, and Brunekreeft and Rammerstorfer’s (2020) distinct finding that a regulated firm facing operating-cost risk can lower its own risk, and therefore its true cost of capital, by shifting spending toward CAPEX and away from risk-bearing OPEX – a bias that persists independently of whether the allowed rate of return is itself excessive. International approaches to resolve the CAPEX bias have included the TOTEX approach (e.g. UK- Ofgem, Netherlands – ACM). Recent regulatory economics reviews press the importance of fixed-OPEX-CAPEX-share (FOCS) mechanism,” even in a TOTEX approach in avoiding CAPEX bias (Brunekreeft and Rammerstorfer, 2020).

This capital bias in Australia has notably persisted despite the AER’s own 2023 review of all incentive schemes, which resulted in incremental adjustments rather than a fundamental redesign (AER, 2023a, 2023b; AER 2024d, 2024e). The review is itself a well-documented illustration of the harmonisation problem this section identifies. At the time the AER’s Capital Expenditure Incentive Guideline was first published in 2013, the AER estimated that the EBSS delivered around 70 per cent of the benefit of OPEX efficiency gains to consumers and set the CESS sharing ratio at the same 30:70 split between the NSP and consumers on that basis (AER, 2023a). By 2020, however, the value of the EBSS to NSPs had fallen, with consumers’ share of OPEX efficiency gains rising to around 80 per cent, driven by changes in rate-of-return parameters rather than any deliberate policy choice – leaving the EBSS materially less generous to NSPs than the CESS’s then-unchanged 30:70 ratio (AER, 2023a). The AER’s own final decision

⁴⁰ The CESS, STPIS, and EBSS jointly make up the bulk of the incentive payments.

acknowledges that this growing imbalance “may distort incentives by encouraging cost shifting from OPEX to CAPEX or increasing management effort to cut CAPEX compared to OPEX” (AER, 2023a, p.12) – in other words, the regulator’s own final decision document names the precise mechanism this section is concerned with.

Industry and consumer stakeholders both proposed aligning the two ratios in response to the AER’s draft decision: the Australian Energy Council (AEC), drawing on advice from Boardroom Economics, recommended increasing the EBSS sharing ratio to 30:70 in line with the CESS, using benchmarking to drive OPEX efficiency closer to the frontier, and reviewing the case for a TOTEX approach in the Australian context; the Consumer Challenge Panel made a similar alignment proposal arguing for the alignment of the two schemes (AER, 2023a). Stakeholders also proposed that the AER consider menu regulation modelled on Ofgem’s earlier approach in Great Britain; the AER declined, noting that Ofgem itself had since moved away from menu regulation (AER, 2023a). The AER’s 2023 final decision retained the EBSS in its existing form – which allows networks to retain efficiency gains for six years and delivers a sharing ratio, currently around 20:80, that moves with rate-of-return parameters rather than being fixed – reasoning that NSPs had continued to reduce OPEX despite the lower EBSS sharing ratio, and that a consistent cost allocation methodology allows the imbalance to at least be monitored and reported on transparently over time (AER, 2023a).

The CESS itself, however, was not left unchanged. The AER (2023a) subsequently amended the Capital Expenditure Incentive Guideline to replace the flat, symmetric 30:70 sharing ratio with a “Bright-Line Tiered Test”: underspends of up to 10 per cent continue to attract a 30:70 sharing ratio, but underspends beyond that threshold attract a tighter 20:80 ratio, while a symmetric 30:70 ratio continues to apply to all overspends. The AER’s stated reasoning for this asymmetry was threefold: that the risk of NSPs over-stating forecast CAPEX requirements exceeds the risk of under-stating them, given persistent information asymmetry despite improvements in the AER’s own assessment toolkit and stakeholder engagement, so a tiered underspend test offsets this asymmetric forecasting risk; that information asymmetry is inherently greater for CAPEX than OPEX forecasts, because CAPEX is less recurrent, justifying symmetric treatment under the EBSS but asymmetric treatment under the CESS; and that asymmetric treatment is consistent with the broader design of the NER, which already permits the AER to exclude inefficient overspends from an ex post review but provides no equivalent mechanism to review underspends. In practice, this amendment moved the CESS’s de facto sharing ratio for larger underspends (20:80) closer to the EBSS’s own prevailing ratio (also around 20:80), even though this was not achieved through the direct ratio alignment the AEC and Consumer Challenge Panel had originally proposed. Whatever the merits of the specific mechanism chosen, the episode still illustrates the piecemeal pattern this section identifies: rather than undertaking the more fundamental redesign its external advisers had proposed – aligning incentive strength across schemes through a single change, or reconsidering TOTEX – the AER introduced a further layer

of scheme-specific complexity, applied only to the CESS, to bring the two schemes' outcomes closer together indirectly.

These tensions have been recognised also in the AEMC (2026c) consultation paper, which is currently examining the same CAPEX/OPEX incentive imbalance, including CESS–EBSS interaction and whether a TOTEX approach should be adopted in Australia to reduce the CAPEX bias.⁴¹

The treatment of the Demand Management Incentive Scheme and Innovation Allowance Mechanism in the same review reinforces this picture. While the DMIS and DMIAM are intended to promote demand-side and non-network solutions as a counterweight to the CESS's capital-expenditure focus, they operate at a much smaller scale than the EBSS and CESS and often require more complex evidence of benefit to access. As a result, non-network solutions can face higher practical hurdles in competing with traditional network augmentation, reinforcing existing investment patterns rather than correcting for them (Cantley-Smith et al., 2023). Tellingly, the AER's 2023 review - despite being a comprehensive review of "all incentive schemes" - explicitly declined to further examine the DMIS and DMIAM at that time, noting only that the schemes had incentivised "several projects" and proposing to extend their application to export services, without reconsidering their design, scale or interaction with the CESS (AER, 2023a, AER 2023c).

This is a direct illustration of the underlying critique: the National Electricity Rules themselves require the AER, in developing any CESS, to take into account "the interaction of the scheme with other incentives that Distribution Network Service Providers may have in relation to undertaking efficient operating or capital expenditure" (NER cl.6.5.8A(d)(1)) – a clear statutory basis for holistic consideration of scheme interactions – yet the 2023 review, the most comprehensive opportunity to date to give effect to that requirement, adjusted the CESS in relative isolation from other schemes and left the DMIS and DMIAM largely untouched. The result is an incentive framework in which the scheme most likely to drive capital-intensive solutions (the CESS) has received the most sustained regulatory attention, while the schemes intended to counterbalance it (DMIS, DMIAM) have received comparatively little, despite a statutory mandate that in principle already requires the AER to consider them together rather than sequentially.

The AEMC's ongoing review (AEMC, 2026c) has also flagged the future role of the DMIS as a specific line of inquiry, alongside broader questions about innovation incentives given the DMIAM's low funding cap.

⁴¹ The-AEMC's current consultation papers also foreground risk allocation as an explicit, unifying frame - demand, cost/delivery, asset stranding, and regulatory/sovereign risk - that this section addresses only implicitly, through the individual mechanisms discussed above (form of control, CESS, EBSS).

Ofgem’s TOTEX approach, which evolved over roughly two decades of regulatory review and refinement (Frontier Economics, 2017; McHarg, 2011), is often cited as a model for a more genuinely harmonised approach to incentivising an efficient mix of capital-intensive and non-capital-intensive solutions (Kuiper, 2024; AEC, 2023). It should not, however, be treated as a ready-made or self-executing solution. A more critical, EU-level assessment (Pototschnig and Rossetto, 2024, drawing on the European Commission’s 2023 EU Action Plan for Grids) finds that

The NER glossary defines a contestable service as follows (emphasis added)

Contestable

(b) In relation to distribution services, *a service which is permitted by the laws of the relevant participating jurisdiction to be provided by more than one Distribution Network Service Provider as a contestable service or on a competitive basis.*

Non-contestable services are not separately defined.

a TOTEX approach only neutralises capital bias where the regulator fixes the CAPEX-OPEX split in advance and holds it constant regardless of the mix of solutions a firm actually adopts, and that this condition is not reliably met even in schemes that describe themselves as TOTEX-based.

This suggests that harmonisation in the Australian context would need to be a deliberate design choice about how the CESS, EBSS, DMIS and DMIAM and other schemes interact and are jointly calibrated, rather than the adoption of a single instrument (whether TOTEX or otherwise) assumed to solve the problem on its own. We therefore pose that a fundamental harmonisation exercise – rethinking the interactions between Australia’s separate incentive schemes as a single, jointly calibrated system, rather than as independently administered mechanisms – should be explored by the rule-maker.

It remains unclear whether the current incentive framework represents the most economically efficient option available (especially in light of the UK’s transit to a TOTEX framework), and to what degree scheme interactions and differential utilisation structurally favours traditional “poles and wires” investment over distributed or flexible alternatives. *Future research should evaluate how effectively the regulatory framework measures and rewards demand management and DER integration outcomes, relative to traditional reliability- and expenditure-based metrics,* and should consider whether a single, integrated incentive instrument, or a more deliberately coordinated set of separate instruments, offers the more promising path to the balanced outcomes the NEO requires.

4.5 Network services of the future – Who can and should provide them?

The final issue we have identified in our research is the lack of clarity on how to regulate potentially contestable services. This creates uncertainty in the regulatory framework. At the

heart of this issue sits the question of whether and which network services could become subject to competition, and how this impacts the regulation of networks.

Underpinning network regulation is the assumption that *only* a network can deliver certain services. The separation between what is considered a service only a network should and can deliver and what can be supplied by other actors (on a competitive basis) is however becoming increasingly difficult to make.

This is part of a wider discussion regarding the integration of DERs and questions of which actors should perform which roles in the distribution system (e.g. Burger, 2019). The focus of the discussion is on how to support more competitive provision of non-network or OPEX alternatives to investment in conventional network assets. Achieving these objectives may require a reassessment of existing industry structures to ensure they remain fit for purpose. (Burger et al, 2019; Kuiper, 2024).

The advent of new technologies such as demand side management or storage solutions allow for avoided infrastructure investment and these non-network alternatives. How services are defined (as standard control service or not) is crucial for the approval of proposed capital expenditure. Only capital expenditure allocated to standard control services can be approved by the regulator (see also Section 3.1 above, which sets out Network Services in detail). At the same time, we are seeing networks engaging in contestable environments, such as kerbside charging services, using a waiver system managed by the AER to provide an exemption for the network, as a natural monopoly, to engage in these services. These developments point to a need to redefine the scope of networks' services, which in turn links to whether and how networks can get remunerated for their CAPEX and OPEX.

In the following sections 4.5.1-4.5.3, we expand on the issues of involving third party services in the delivery of services as well as the flipside, the engagement of networks in contestable services. We also expand on the question of whether the separation of network ownership from operation could address some of these issues.

4.5.1 Contestability of network services

The question of whether distribution network services can still be considered to be true monopoly services has been raised by others (e.g. Kuiper 2024). As technology develops, non-network solutions, such as VPP or other orchestrated demand response, or the use of storage to shift demand, have the potential to replace costly network investment. As set out in Section 3 above, the NER already require the DNSP to consider non-network options in both the planning process under Chapter 5 and when considering credible options for the RIT-D, as well as when forecasting expenditure under Chapter 6.

Yet, we have not yet seen consistent uptake of non-network options, even though technologies that can provide these options, are developing rapidly. CAPEX solutions may be favoured for a number of reasons, including the Averch-Johnson effect (higher rate of return on capital than

the true cost), an OPEX-disadvantage when the OPEX risk is not fully captured in regulation and where asymmetric regulation leads to a CAPEX bias (Brunekreeft and Rammerstorfer 2020). Non-network solutions provide alternatives to investing in assets and growing RAB, which is the traditional business model of a DNSP. Although networks can recover most prudent and efficient costs, consumers ultimately bear much of the risk, including in cases of cost overruns, as we have also set out in Section 4.4 above, this provides incentives to favour CAPEX solutions. A report by KPMG also added familiarity with capital investment over non-network options as one of the potential reasons for a CAPEX preference (as cited by Kuiper 2024).

Other issues concern questions of control and risk management. Where third parties are contracted to procure services a network is responsible for, the question of regulatory oversight of these entities should be considered. It is ultimately networks who are responsible for service delivery vis a vis the regulator, not the subcontracted entity. This adds complexity to the task of a DNSP.

We have already raised the question above of whether current regulatory settings hinder efficient investment and slow the energy transition. Incentive schemes have, thus far, had limited success in shifting network preferences to non-network options. As technology develops, the natural monopoly character of networks will be further threatened. While at this stage, networks can procure non-network options to deliver the services they are responsible for, in future, there may be genuine competition between non-network providers and networks.

A review of how services provided are defined, incentivised and remunerated will be central to a future facing electricity system. These will have to be embedded in the investment framework for distribution networks.

4.5.2 Ring-fencing and the provision of contestable services by networks

As another development, we are seeing networks active in contestable (competitive) services in a departure from strict unbundling rules.

As set out in Section 2.4, ring-fencing⁴² operationalises the strict unbundling of network operation from activities which can be provided by other parties.

Ring-fencing rules seek to ensure that networks do not abuse their monopoly position, discriminate against potential competitors, or limit entry of third parties to emerging competitive market segments. This means that networks can generally not compete with third parties to deliver non-network services. However, there may be situations where it is in the

⁴² As set out in 2.4 (fn 8) above, ring-fencing is the “separation of monopoly services and contestable services where a regulated business also offers services into a competitive market.”

interest of consumers to have a network deliver in a competitive market, especially where sufficient competition has not yet emerged or is unlikely to emerge.

In the NEM, this is made possible by an exemption (waiver) framework managed by the AER.

The Ring-fencing Guideline Distribution (AER, 2025a) made under NER 6.17.2 sets out under which conditions a network can provide these services.

When assessing a waiver application the AER:

subject to clause 5.3.3(a), must have regard to:

- i. the National Electricity Objective;
- ii. the potential for cross-subsidisation and discrimination if the waiver is granted or refused;
- iii. whether the benefit, or likely benefit, to electricity consumers of the DNSP complying with the obligation (including any benefit, or likely benefit, from increased competition) would be outweighed by the cost to the DNSP of complying with that obligation; ...

We see networks operating on ringfencing exemption frameworks and offering non-network services, such as providing public electric vehicle charging stations or operating batteries.⁴³ Networks argue that competitive third-party providers are not available in particular locations, or cannot deliver the services they propose to deliver fast enough or at the same scale (e.g. CPU, 2024, in the context of a kerbside charging trial). Independent third-party service providers pose that networks are excluding them from service provision and are suppressing emerging markets if allowed to provide these services (e.g. Flow Power, 2025).

The AER has in June 2026 announced a review of the ring-fencing guideline enquiring into these questions (AER, 2026a). They are expressly asking for input on (AER, 2026a, p.10):

- the appropriate boundaries of DNSP activity,
- the conditions that should apply where DNSPs or their affiliates participate in emerging services,
- and how the framework should manage risks of cross-subsidisation, discrimination or market distortion while allowing efficient and innovative solutions to be tested where they may be in the long-term interests of consumers.

⁴³ See for example the application for ring-fencing waiver from CitiPower, Powercor, and United Energy to allow them to provide and maintain kerbside EV chargers, AER (2025f).

Within the scope of this review the question to add is *whether and how allowing networks to move into the provision of (potentially) competitive services interfaces with network investment processes and their fitness for purpose.*

If applying for exemptions becomes the norm, rather than the exception, the market is not delivering third party services. Regulators will have to consider whether it is more efficient that non-network solutions become part of the suite of services a network provides and how these solutions can be appropriately incentivised over capital investment solutions.

4.5.3 From DNSP to DSO

In December 2025 the Consumer Energy Resources Taskforce provided their final advice to Energy Ministers on “Redefining roles and responsibilities for power system and market operations in a high CER future” (Australian Government, 2025), proposing that DNSPs should be given a formalised role of Distribution System Operator (DSO). The taskforce distinguishes four distinct roles DNSPs are performing: asset owner, distribution planner, DNO (Distribution Network Owner) and DSO roles. One of the recommendations for reform of the taskforce is a call for clear guidance on how to minimize network investment costs and maximise the value of CER. The report already flags the potential conflicts between the investment incentives provided by the system in the context of the role of the DNSP as the distribution system planner and the more comprehensive role of a DSO and emphasises the need to address preferences for network solutions over non-network solutions. The formalisation of a distinct DSO role – whether undertaken by the DNSP as currently recommended or by a third party – has the potential to incentivise better use of existing resources and better integration of consumer resources. Whether this potential can be achieved will depend on how incentives are set. Burger et al. (2019) considers regulatory mechanisms that align incentives with cost-efficiency objectives and provide equivalent financial incentives for both capital and operational expenditure essential for a successful DSO/DNO arrangement. The taskforce is pointing to the DMIAM/DMIS as incentives already supporting DSO-type activities.

Given the shortcomings of these mechanisms as pointed out in 4.4 above, *we suggest that the design of a DSO incentive mechanism should be accompanied by a reconsideration of whether and how different incentive schemes may be providing competing incentives.*

We note that AEMC’s 2026 Package 2 review is, inter alia, exploring what incentive arrangements are needed to support the DSO role the Energy Ministers agreed to formalise in December 2025 (AEMC, 2026c).

5. Summary and Recommendations

This report set out to examine whether the National Electricity Market's current regulatory arrangements around network investment remain fit for purpose through a systematic process-mapping of the institutional architecture governing distribution network investment. This report should be read alongside its companion comparative literature review (Csereklyei and Kallies, 2026), which situates the Australian framework against international experience and is referred to throughout the report.

The guiding question for our assessment was whether regulatory arrangements are capable of facilitating timely, efficient and forward-looking investment that meets both current and future challenges.

This review arrives at a moment of unusually dense regulatory activity. The AEMC's Network Regulation Review is proceeding in two packages: Package 1, a six-months sprint concluding in late 2026 (AEMC, 2026b), addresses service classification and ring-fencing, alongside related rule changes on ring-fencing and electric vehicle charging infrastructure; Package 2, running to the end of 2027 (AEMC, 2026c), will examine incentive design, risk allocation, and the regulatory determination process, including DSO incentives. In parallel, the AER has published a Future of Electricity Network Regulation information paper (AER, 2026b) and is reviewing the ring-fencing guidelines (AER, 2026a). Our report informs these discussions through an in-depth, process-level analysis of the distribution investment framework specifically, rather than a high-level policy statement.

We identified four major areas of improvement in the discussion in Section 4.

First, assessing the institutional design for the regulatory frameworks for network investment, we found that the multiplicity of rule-making and review bodies, and the prescriptiveness of the National Electricity Rules relative to comparator jurisdictions, constrains the AER's and AEMC's ability to adapt the framework quickly. We see this as a barrier to responding to change rapidly and proactively – thereby impacting the ability for timely investment in the system to facilitate the energy transition.

The second identified issue concerns the lack of interface between network planning and economic regulation. Chapters 5 and 6 of the NER, which respectively govern the physical and the economic planning process, are not formally connected in the national rules. Thus, the separate five-year forecasting and revenue determination process governed in Chapter 6, required alongside the physical network planning governed in Chapter 5, as well as a separate RIT-D process (Chapter 5) create overlapping and at points duplicative assessment of the same investment decisions.

Additionally, the length of the regulatory period associated with economic forecasts (5 years) is recommended to be examined in the future. While the level of regulatory prescriptiveness may appear overly restrictive in a rapidly evolving environment, the timeframe may nonetheless be insufficiently flexible to support anticipatory development and transition-enabling investments, potentially leading to socially suboptimal investment outcomes. We identified a lack of long-term “transition enabling investments”, which cause a “horizon problem” where networks are forced to invest with a mid-term horizon, and potentially carry out piecemeal adjustments. We also identify the challenge networks encounter in changing or deviating from the current mid-term forecasts, which we call the “level of detail problem”. Thus, many investments continue to be incremental. We see this gap as impacting the ability for timely and forward-looking investment.

Third, on incentive regulation, we found that Australia’s incentive schemes - currently comprising six main scheme types combined with a revenue cap regulation - have developed piecemeal and can work at cross-purposes. A more unified, deliberately designed incentive framework could achieve more than the sum of its parts. A persistent capital-expenditure bias remains only partially addressed by existing mechanisms such as the DMIS. These settings may reduce the efficacy of the designed regulatory framework, which in turn impacts the ability to invest in an efficient and forward-looking manner. We recommend exploring incentive designs that are able to address the CAPEX-bias as well as increase the efficacy of network incentive regulation as a whole.

Fourth, on contestability and the DNSP-to-DSO transition, we find that service classification boundaries are increasingly tested by emerging services that can provide non-network alternatives to network investment. At the same time, we see networks actively engaging in contestable activities, such as EV charging and storage, facilitated by a ring-fencing waiver system. We suggest that an in-principle review of where boundaries between regulated and unregulated services are drawn should need to be undertaken with reference to the outcome they are meant to protect. This work needs to be undertaken in tandem with reviewing the incentive regulation framework to ensure that investment remains timely and efficient.

Taken together, these findings suggest that the current reviews now underway are in principle well placed to address parts of this picture, but not all of it. AEMC Package 1 (AEMC, 2026b) and the AER ring-fencing review (AER, 2026a) will investigate the contestability and ring-fencing findings above; Package 2 (AEMC, 2026c) speaks to incentive design and DSO incentives.

How the issues identified in this review will be addressed, remains to be seen. Neither package, as currently scoped, squarely addresses the planning-investment interface finding – in particular the “horizon problem” and the “level of detail problem”. If the planning-interface duplication is left unaddressed, the risk is that reforms progressed through Packages 1 and 2 improve incentive and boundary settings without resolving the underlying duplication and rigidity in how investment need is identified and approved in the first place. The overarching issue of whether

the framework's overall design and governance structure is suitable for the future is not addressed in the proposals. These discussions should be undertaken at a policy level through the Ministerial Council rather than within the review and rule change processes.

We pose that all issues identified here require more detailed research. While they can be researched separately, reform proposals will need to account for the interactions between each of the proposed changes to the regulatory frameworks. Individual rule change proposals will not be sufficient to prepare the framework for the future.

Appendix 1

Networks and Ownership Structures in the NEM:

In Australia's NEM, each network is responsible for a separate geographical area. Each state has one Transmission Network Service provider (Transmission Services for the ACT are provided by Transgrid, the NSW TNSP), and one or more Distribution Network Service Providers.

Transmission Network Service Providers:

Queensland: Powerlink Queensland, State-owned

NSW/ACT: Transgrid, privately owned

Victoria: AusNet, privately owned (with two further privately owned TNSPs, Lumea and Transmission Operations Australia, operating select assets)

South Australia: ElectraNet, privately owned

Tasmania: TasNetworks, State-owned

Distribution Network Service Providers:

Queensland has two DNSPs:

Ergon Energy and Energex, both State-owned.

NSW/ACT has four DNSPs:

Ausgrid (50.4% privately owned), Essential Energy (State-owned), Endeavour Energy (50.4% privately owned), EvoEnergy (50% privately owned)

Victoria has five DNSPs :

Powercor Australia, Jemena, AusNet Services, United Energy Distribution, and Citipower, all fully privatised

South Australia has one DNSP:

SA Power Networks, fully privatised

Tasmania has one DNSP: TasNetworks, State-owned

Appendix 2

Table: Key AER guidelines in effect as of July 2026.

Category	AER guideline / instrument	What it governs	Authorisation
Emissions valuation	Valuing of Emissions Reduction (AER 2024)	To provide guidance, as contemplated by the emissions reduction amendments to the National Electricity Law, about valuing emissions reductions in regulatory processes under the National Electricity Laws	NEL s42
Investment decision-making	Regulatory Investment Test for Distribution (RIT-D) – Application Guidelines (November 2024)	Mandatory process for assessing major distribution investments, including consideration of emissions impacts where relevant market benefits are assessed	NER 5.17.2a
Investment decision-making (binding instrument)	RIT-D Instrument	Legally binding specification of market benefit classes, including emissions reduction as a permissible class where applicable	NER 5.17(c)
Transparency & early identification of needs	Distribution Annual Planning Report (APR) template (2017)	The DAPR template will improve the consistency and useability of DAPRs across the National Electricity Market and will improve the ability for non-network providers to identify and propose solutions to address identified network needs.	NER 5.13.3
Consumer Engagement	Better resets handbook (July 2024)	Seeks to encourage networks to better engage and have consumer preferences drive the development of regulatory proposals	No legal basis

Consumer Engagement	Consumer challenge panel (established 2013)	The Consumer Challenge Panel is a panel of experts which advise the AER on whether the long-term interests of consumers are being appropriately considered in regulatory proposals and the AER's decision making, and provides an assessment of consumer engagement processes undertaken by network businesses	No legal basis
Revenue assessment of investments	Expenditure Forecast Assessment Guideline for electricity distribution (October 2024)	The Guideline must specify: - the approach the AER proposes to use to assess the forecasts of operating expenditure (OPEX) and capital expenditure (CAPEX) that form part of the regulatory proposals - the information the AER requires for the purposes of that assessment.	NER Chapter 6.2.8(a)(1)
Incentives affecting planning behaviour	Capital Expenditure Incentive Guideline for Electricity Network Service Providers (August 2025)	This guideline complements the incentives a NSP already has to deliver efficient CAPEX. It outlines new ex ante and ex post measures to further incentivise efficient CAPEX. There are three main aspects to this: 1. We have developed a Capital Expenditure Sharing Scheme (CESS) to share efficiency gains and losses between NSPs and network users. 2. We have developed criteria for deciding whether to roll forward the RAB using depreciation based on forecast or actual CAPEX.	NER 6.5.8A, 6.4A

		3. There are new ex post measures to ensure that network users do not bear the costs of inefficient or imprudent overspends, capitalised operating expenditure (OPEX) or inflated related party margins	
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Abbreviations

Abbreviation	Full term
AEC	Australian Energy Council
AEMA	Australian Energy Market Agreement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CAPEX	Capital Expenditure
CER	Consumer Energy Resources
CESS	Capital Expenditure Sharing Scheme
COSR	Cost of Service Regulation
CSIS	Customer Service Incentive Scheme
DAPR	Distribution Annual Planning Report
DER	Distributed Energy Resources
DMIAM	Demand Management Innovation Allowance Mechanism
DMIS	Demand Management Incentive Scheme
DNDP	Distribution Network Development Plan
DNO	Distribution Network Owner
DNSP	Distribution Network Service Provider
DSO	Distribution System Operator
EBSS	Efficiency Benefit Sharing Scheme
IASR	Inputs, Assumptions and Scenarios Report

Abbreviation	Full term
ISP	Integrated System Plan
NEB	Net Economic Benefit
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NSP	Network Service Provider
OPEX	Operating Expenditure
PCR	Price Cap Regulation
RAB	Regulated Asset Base
RCR	Revenue Cap Regulation
REPEX	Replacement Expenditure
RIIO	Revenue = Incentives + Innovation + Outputs
RIT	Regulatory Investment Test
RIT-D	Regulatory Investment Test Distribution
RIT-T	Regulatory Investment Test Transmission
RPI-X	Retail Price Index minus X
SAPS	Stand-Alone Power System
SEC	State Electricity Commission
STPIS	Service Target Performance Incentive Scheme
TNSP	Transmission Network Service Provider

Abbreviation	Full term
TOTEX	Total Expenditure
VCR	Value of Customer Reliability
VPP	Virtual Power Plant
WACC	Weighted Average Cost of Capital

RACE for 2030

RELIABLE
AFFORDABLE
CLEAN
ENERGY



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