Submission on AMEC's Electricity Network Regulation Review Package 1 consultation paper

Reference: EPR0106, ERC0435, ERC0437
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I am making this submission in response to some of the consultation questions in the Electricity Network Regulation Review Package 1 consultation paper. The views below are my own, not reflective of any of my employers/clients and are consistent with positions I have set out in earlier published work, including *Reforming the economic regulation of Australian electricity distribution networks* (IEEFA, May 2024), *Growing the sharing energy economy* (IEEFA, October 2023), *How rapid implementation of flexible exports could maximise rooftop solar* (IEEFA, December 2024), *The Future of Electricity Networks* (Churchill Fellowship report, 2019), and *NEM Reform: Unlocking the demand side in future energy markets* (Energy Efficiency Council, July 2025). All of these reports are available at www.gabriellekuiper.xyz and I have attached the first and last of these reports to this submission as they are directly relevant to this subject matter.

Opening statement

This review is overdue. The economic regulation of distribution networks was developed for a much simpler electricity system, where electricity flowed one way, government-owned distribution businesses were largely passive owners and operators of poles and wires and substations, and most consumer-side capability was irrelevant to network operation. That is no longer the system we have.

As the consultation paper acknowledges, Australia now has the world's highest penetration of rooftop solar per capita, rapidly growing behind-the-meter (BTM) storage capacity, increasing electrification, and a clear need to integrate household and business owned distributed energy resources (DER or CER) in ways that lower the cost of the energy transition for all consumers. At the same time, distribution businesses are becoming active distribution system operators (DSOs), managing their networks in a way that was unthinkable when the National Electricity Rules (NER) were first written.

This new world requires a fresh, first principles examination of the role of electricity distribution networks. Across my recent work, I have made a consistent argument: regulation should not assume that the monopoly network should own, control or *directly provide* every service associated with the future grid. Regulation should create a level playing field between traditional network infrastructure and DER-provided services, remove bias towards capital expenditure, support decarbonisation and electrification, and preserve room for competition, innovation and consumer choice. I set this argument out in detail in *Reforming the economic regulation of Australian electricity distribution networks*. The need for support to enable networks to be able to innovate is particularly important in the fast-changing technological environment, where, for example, vehicle-to-home can provide cheaper back-up supply than diesel generators, fast EV charging is being enabled at higher and higher wattages, flexible PV technology is developing apace and vehicle-to-grid is rolling out at scale in several Chinese cities, showing what the future could look like, if only we pay attention.

Given all this, the central question for Package 1 is not simply where to draw technical legal boundaries on service classifications or ringfencing. The deeper question is how we define a regulated monopoly for an electrified, high-DER decarbonising economy. This is about what is economically efficient and what is in the public interest. I would suggest we need to redefine the economic regulation such that DER can provide substantial value to the distribution network on at least a level playing field, if not prioritised over capital-intensive infrastructure spend. At the same time, we also need to ensure that decarbonisation is front and centre of network regulation.

While the issues about ringfencing, especially the contestability of EV charging provision are important, today's specific points of contention must not overshadow the necessity of a thorough examination of the role of distribution networks in a decarbonised, electrified future.

Question 1. Prioritisation framework for the Review

I strongly support the assessment criteria with outcomes for consumers listed before market efficiency and it is a relief to see both the achievement of emissions reduction and principles of good regulatory practice listed.

The proposed prioritisation approach is sensible, but it could give greater weight to the risk of structural lock-in. In a fast-moving transition, the largest consumer harm may come not only from the materiality of a current issue, but from allowing a regulatory choice made now to foreclose competition, innovation or lower-cost pathways for many years. I suggest one way to approach this would be to include an additional criterion to ensure the review focuses on issues that are related to electrification and decarbonisation and innovation (future-focused) – looking at least thirty years into the future given that how long the economic regulation has been in place without any fundamental reforms. It is important to add this criterion to counter the risk that Implementation feasibility dominates and circumscribes what's examined. If done well, some of the change resulting from this review will be hard, not easy to implement.

Question 2. What network services should be subject to economic regulation and are changes to the service classification framework required?

2.1 What changes should be made to the service classification arrangements?

In both *Reforming the economic regulation of Australian electricity distribution networks* and *The Future of Electricity Networks*, I questioned the assumption that distribution services should continue to be treated as purely monopoly services when DER can substitute for traditional augmentation, manage congestion, support exports and provide other services once thought to be only able to be provided by poles, wires and transformers.

It is very helpful to see the consultation paper stating that 'services are increasingly understood in terms of the functions they perform (e.g. electricity conveyance, orchestration of distributed resources, optimisation of system performance, provision of digital platforms)'. The current definition of a distribution *service* ties it to a distribution *system* and the definition of a distribution system is tied to infrastructure, in terms of a distribution network. This is highly problematic in an age where distributed energy resources can provide the same services as the infrastructure itself, and where software can increasingly enable DER to provide non-network solutions, or 'distribution flexibility' in British terminology. I would argue that distribution infrastructure is no longer a monopoly given DNSPs can procure 'network services' transparently and competitively from DER owners, aggregators, retailers or other providers.

Therefore, the rules need to redefine distribution services as actual services, not as infrastructure. For example, these service definitions could include:

- active (potentially real-time) management of imports and exports,
- the service of new connections for imports and exports, and
- the service of enabling electrification, including for EV charging and for vehicle-to-home and vehicle-to-grid uses and for commercial and industrial electrification.

There is also the service of resilience in a changing climate, which is not highlighted in the consultation paper, but is increasingly important for consumers and the country as a whole.

My starting point is that only those services that are genuinely monopoly in character, and cannot reasonably be provided or procured competitively, should be subject to economic regulation. Core shared network transport and system security functions will likely remain regulated. But many services associated with managing demand, exports, flexibility and local constraints should not be automatically treated as monopoly services *only able to be provided by infrastructure* because that's the way it has previously been done.

As the consultation paper makes clear, the current timing of classification decisions is also a problem. Decisions made before the start of a five-year regulatory period are poorly suited to a fast-changing, software-enabled, DER-rich environment. In *Reforming the economic regulation of Australian electricity distribution networks*, I identified the long five-year period, staggered reviews and propose-respond model as features that can limit flexibility and innovation. The Rules should therefore allow a more adaptive reassessment of classification where a service is new, evolving or likely to become contestable during the regulatory period. I am not suggesting constant churn. I am suggesting a mechanism to revisit classification where technology, market participation or policy changes materially alter the case for monopoly provision. However, this point may not be so urgent or necessary after a fundamental rewrite of the definition of distribution service and distribution network in the rules.

2.2 Circumstances where NSPs might provide regulated services in contestable markets

I support an entitlement for NSPs to provide regulated or non-regulated services in contestable markets where it assists with facilitating electrification and decarbonisation to lower costs for consumers and ensure Australia meets its emissions reduction targets. Examples of these services are workforce training, the offering of electrification services to customers and widespread electrification of precincts and neighbourhoods. I believe networks should do what networks do best and electricity networks will often be best placed to transition consumers off gas and ensure their electrification can be done in a way that doesn't increase the cost of the network *provided* the capex bias is removed (see my reports for the evidence that this exists and is material). So the limitations on networks are inherently tied to the broader questions of how they are remunerated (Package 2). Strong transparency and data access protections for consumers should also apply wherever NSPs play in contestable markets.

2.3 Guidance in the Rules the DSO role

The DSO role is, in my view, simply the logical evolution of DNSPs—to be able to manage their networks more dynamically with greater visibility, smarter software and the use of distribution flexibility provided by DER. The National Electricity Rules (NER) needs to reflect this evolution by making it clear that lower cost non-network solutions should be preferred in planning and procurement over costly network capex.

Question 3. Are changes required to the ring-fencing arrangements?

3.1 Effectiveness of ring-fencing obligations to date

Because I have not been closely engaged with the Australia Energy Regulator's (AER's) recent ringfencing decisions, it is unclear to me how much the issue is the arrangements themselves and how much has been the AER's interpretation of those arrangements. Of the recent approvals, the AER appears to have taken liberties with consumers' best interests by approving Ausgrid's community power network trial, in particular. Under this trial, Ausgrid are not only playing in a competitive market, that of rooftop solar and batteries, but stating they are doing so to reduce the amount of network augmentation required when there is ample headroom in the areas of the trials. I commend Simon Orme's analysis showing there are no network cost or price reductions from flattening the load profiles for Ausgrid's proposed assets to the Australian Energy Markets Commission (AEMC).

Unfortunately, the AER's decisions lead me to conclude ring-fencing should therefore be strengthened, not diluted. The starting point should not be that monopoly networks can enter a market unless harm is proven after the fact. The starting point should be that DNSPs do not enter unless a strong public interest case e.g. for electrification or decarbonisation is demonstrated in advance.

Question 9. ENA rule change request – Do you agree with ENA that there is a problem with the roll out of EVCI?

Yes. There is absolutely a fundamental problem with the rollout of EV charging, but it is a problem that governments should take charge of — bad pun intended. Planning for EV charging should ideally take into account integrated transport and land-use planning, current needs and forecasts and the current and forecast state of the distribution network. It also needs to take into account the potential for EVs not just to import from the grid, but increasingly to export to the grid, and should be future-focused, preferably leapfrogging straight to vehicle-to-grid charging where that is appropriate.

This is a large policy problem that should be addressed at the policy level, not primarily through the NER. It is not appropriate for the AEMC to try to solve what is fundamentally a policy and planning problem through a regulatory classification decision. In particular, planning for EV charging should be undertaken in conjunction with local governments, which best understand land-use and transport demand in their areas, while also drawing on DNSPs' understanding of local network conditions and constraints.

Question 10. ENA rule change request – Would ENA's proposed solution address the identified problem?

By contrast, classifying EV charging infrastructure as a regulated service for DNSPs will not produce the best outcome for consumers. Electricity distribution networks do not have the skills, capacity or experience to take into account the full transport and land-use planning considerations that should shape the rollout of public charging. It is also likely to encourage over-investment in public EV charging at a time when the pace of technological change is highly uncertain, including the extent to which vehicle-to-home and vehicle-to-grid capability will change the nature, timing and location of charging demand.

The AEMC should therefore avoid offering a regulatory solution to what remains an unresolved policy question. Instead, it should make clear to federal, state and local governments that policy direction is needed before any enduring change is made through the Rules. This is undoubtedly an urgent issue, but urgency is not a reason to leap straight to a simplistic solution that risks locking in inefficient outcomes.

In terms of cost recovery, all electricity consumers should not pay for the rollout of EV charging infrastructure. Not all electricity consumers are EV drivers, and the implications for different classes of transport use — including electric buses, trucks and other vehicles — remain unclear. Socialising these costs too early is likely to encourage over-investment at exactly the moment when the technology, usage patterns and market model are changing rapidly.

Question 12. Assessment criteria

See answer to question 1.

Closing remarks

I note that Great Britain started working on reforming the economic regulation of its networks in 2010. This Review has a hard road ahead. Among other things, the Review needs to define clearly what is now and what is likely to be genuinely monopoly network services in a way suitable for a decarbonising, electrifying and fast evolving energy system; create a durable level playing field for DER and third-party services to provide distribution flexibility (non-network solutions in American parlance); remove the structural preference for capex; support electrification; accelerate decarbonisation and build a regulatory system that rewards efficient coordination and consumer outcomes rather than asset expansion. That approach is more likely to lower bills and preserve public confidence in the transition.

NEM Reform

Unlocking the demand side in future energy markets

July 2025

About this report

This report was funded by the **RACE for 2030 Cooperative Research Centre (RACE)** and prepared by independent expert Dr Gabrielle Kuiper and Dr Dylan McConnell from **UNSW Sydney** for the **Energy Efficiency Council (EEC)**. This report is part of a broader work program on 'Activating the role of the demand side in the National Electricity Market (NEM)' led by the EEC and supported by RACE in the context of the 2025 'National Electricity Market wholesale market settings review' (the NEM Review).

RACE is a cooperative research centre focused on energy and carbon transformation.

The **EEC** is the peak body for Australia's energy management sector. A not-for-profit membership association, the EEC works to:

- Drive world-leading policy on efficiency, electrification and demand flexibility;
- Ensure Australia has the skilled workforce to deliver Australia's energy transition; and
- Support businesses and households to rapidly decarbonise.

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Executive Summary

Unlocking the demand side is essential for reducing the costs of Australia's future electricity system as it transitions to high levels of variable renewable energy. Demand-side resources—including energy efficiency, flexible demand and distributed energy resources (DER) such as rooftop solar, batteries and electric vehicles—can deliver significant system value by improving reliability, reducing costs and enhancing competition. Realising this value requires the coordinated development of market, regulations and deployment mechanisms that support both the effective uptake and integration of distributed and flexible demand-side resources.

The NEM Wholesale Market Settings Review (the NEM Review) provides a timely opportunity to address current structural barriers to the optimisation of the demand-side.

This report sets out design principles and recommendations to unlock the potential of the demand side and ensure its meaningful integration into the future high variable renewable energy (VRE) electricity system. It draws on both international best practice and a detailed understanding of the NEM to examine how to enable demand-side resources—including aggregated distributed energy resources (aggregated DER)—to compete on a level playing field with firmed renewable generation and storage.

The first section of the report on market participation of the demand side is informed by the focus areas and emerging directions of the NEM Review, in relation to short-term spot markets, medium-term derivatives, and long-term investment markets.

The report then considers related mechanisms and institutional arrangements, that both support the delivery of and deployment of demand-side resources, including: distribution network support services (also known as 'non-network solutions'); state and federal policies for technology deployment; and enabling technical and institutional mechanisms.

Spot (short-term) market

The analysis in this paper concludes that common features of markets with effective integration of demand side-resources include: low minimum thresholds (100kW or less), coordination mechanisms between system operators, DER and networks, standardised baseline methodologies, locational pricing and capacity markets. The analysis also identifies aggregation as a common and essential feature that warrants further attention.

Principles for reform to integrate the demand side into the spot market:

- **Granular price signals and stackable value**: Price signals should reflect local, temporal system conditions and enable DER to access multiple value streams.
- **Open market access and equal treatment**: All DER and demand-side resources should be able to participate in markets on fair terms.
- **Clear aggregator role with minimal barriers**: Frameworks should encourage independent aggregator entry and innovation.
- **Data visibility and flows**: Data must be available to appropriate actors for effective system operation and planning.

Recommendations are developed based on these principles and in the context of three separate but related recent rule changes and processes being: the *Integrating price-responsive resources into the NEM* rule change (IPRR); the *Flexible Trading Relationships (FTR)* rule change and the review of the *Wholesale Demand Response Mechanism* (WDRM). The report discusses how these principles could be applied, and how mechanisms could be improved to increase participation of the demand side in the wholesale market.

Recommendations to support fair competition and dynamic market development in the spot market:

- Update existing systems (including NEMDE) to permit aggregated loads of 100kW or less to participate.
- Enable independent aggregators to participate in the spot market as Voluntary Scheduled Resource Providers via an update to the FTR rule.
- Extend the Wholesale Demand Mechanism (WDRM) to small users and households.
- Expand baseline methods in WDRM (including aggregation-friendly baselines).

Medium-term derivatives markets

Forward and exchange-traded derivative products play an important role as a risk management tool for generators and retailers. The changing generation mix and spot market dynamics are proving challenging to hedge with traditional instruments. Innovation of these products is required, and this needs to integrate demand side assets to enable a two-sided market.

Principles for reform to the derivatives markets:

- **Transparency and competition**: Exchange-traded products should be standardised, with clear price signals and broad participation.
- **Market liquidity through aggregation**: Aggregation of demand and supply improves liquidity.
- **Neutral market architecture**: Hedging products should not impede optimal dispatch or integration.

Reform must go beyond spot price formation and consider how demand-side participation can be explicitly and effectively integrated into hedging and frameworks.

Recommendations for reform to the derivatives markets:

- Develop standardised forward products or exchange-traded hedges that support access for flexible demand aggregators and the demand-side more broadly.

Long-term investment markets

Investment in long-lived capital-intensive projects is typically dependent on long-term contracts, to manage revenue uncertainty and securing finance. Historically, these longer-term contracts have not been fully integrated into formal market structures, and in many cases are supported by additional policy mechanisms. There is increasing recognition that additional integrated long-term signals or mechanisms are required to support investment. Principles for contract design which could address these challenges include those set out below.

Principles for reform to long-term investment markets:

- **Revenue certainty**: Long-term contracts must provide stable cashflows to de-risk investments.
- **Balance between price stability and market integration:** Avoid undermining efficient dispatch.
- **Avoid hedging disincentives**: Long-term contracts should not crowd out natural hedging incentives.

- **Appropriate risk allocation**: Contracts should target extreme downside/systemic volatility.
- **Government role for market failures**: Government intervention may be needed for missing long-term markets.
- **Appropriate basis risk design**: Contract reference choices affect risk and incentives.

Some of the principles outlined above are not specific to the demand-side and reflect general principles for efficient design of electricity markets.

Current proposals from the NEM Review Panel to address the tenor gap in the contract market may be poorly suited to supporting investment in demand-side options. The proposed contracting mechanism is designed to enable long-term contracting for utility-scale generation projects, whose financing models depend on reducing risks to revenue over 10–15+ years. In contrast, demand-side resources, including load flexibility, behind-the-meter storage, and distributed generation, are fundamentally different in their characteristics, value drivers, and financing needs.

Recommendations for reform to long-term investment markets:

- Consider mechanisms to support investment that go beyond addressing the tenor gap and are suitable for smaller-scale demand-side resources and aggregators.
- Explicitly design new investment mechanisms to allow larger flexible demand aggregators and demand-side resources to participate.

Distribution network support services

At the distribution level, the existing economic regulation of distribution networks does not provide a level playing field for non-network solutions. There's a need to move to outcome-based revenue determinations that value the demand-side. This report sets out a summary of the arguments for change which have been documented in detail elsewhere.

The economic regulation and the incentives structures of distribution networks should be reformed to reflect the increasingly diverse set of services that distribution networks need to deliver for consumers and for decarbonisation and that consumers could provide to the distribution network.

Principles for reform of the economic regulation of networks:

- Create a level playing field between non-network solutions (DER and aggregated DER) and network solutions
- Introduce commercial discipline into the regulatory asset base (RAB)
- Assess revenue on a cycle consistent with the speed of technological change

Principles for reform - network incentives should be amended to:

- Incentivise network productivity for both imports and exports
- Incentivise voltage management
- Increase the proportion of revenue at risk for customer service
- Incentivise DNSPs to accelerate decarbonisation
- Incentivise DNSPs to become more resilient in a changing climate.

Specific recommendations have not been provided, as further investigation should be carried out into various approaches set out in this Report . However, a straw person of new incentive schemes is set out in section 5, for the purposes of stimulating discussion on new ways of thinking about the economic regulation of distribution networks.

Deployment mechanisms

Deployment mechanisms—such as appliance upgrade subsidies—remain critical for accelerating uptake of energy efficient, flexible technologies, particularly where upfront costs are a barrier. Unfortunately, current subsidy programs are ill-suited to a system with high levels of renewable energy, especially as they fail to account for time-of-day energy consumption. These programs also continue to rely on deemed methods to estimate their impact, an approach which has drawn criticism for overstating energy savings and which can lead to contradictory deployment where time of use is not considered.

Principles for reform of existing government subsidy schemes for technology deployment:

Existing subsidy schemes should evolve to:

- Support the purchase of efficient and flexible appliances and machines, especially where the up-front cost is a barrier to electrification.
- Be accompanied by consumer information and advice.
- Be complementary to market participation and ideally set nationally.
- Consider sub-targets or certificate multipliers for vulnerable cohorts to improve equity.

Technical enablers of aggregated DER

A number of technical and regulatory changes are required to remove barriers to aggregated DER participation in future markets.

Recommendations for reforms to support greater aggregated DER market participation:

- Legislate a DER Technical Regulator.
- Adjust Greenhouse and Energy Minimum Standards (GEMS) to include flexibility capability for major household appliances.
- Create open data and open communication protocols.
- Allow aggregator (third party) access to real-time smart meter data with consumer permission.
- Upgrade market systems for digital, low-cost interfaces, automated dispatch, settlement, and interoperability.
- Accelerate the development of open, secure, and interoperable data sharing across the sector.

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1. Introduction

1.1 The ‘demand side’

With the rise of rooftop solar over the last two decades, many Australian households and businesses have transitioned to be active contributors to supply and, to a lesser extent, system services. The term ‘demand side’ is now commonly understood to encompass a broad range of resources—including traditional consumption (households and businesses, including larger commercial and industrial loads) as well distributed energy resources (DER) including rooftop solar, smart appliances, batteries and electric vehicles that are capable of feeding energy back into the grid. This report also includes aggregation of DER (or aggregated DER), often referred to as Virtual Power Plants, in the definition of the demand-side. Consumer Energy Resources (CER) is a recent term referring to energy resources that are owned or controlled by consumers, a subset of all DER. The analysis in this report focuses on energy market reforms that can support this broad definition of the demand side.

1.2 The forgotten half of the market

Demand-side participation is increasingly critical for efficient, reliable electricity markets—especially during the transition to weather-dependent renewable generation. Historically, markets like the NEM operated under a centralised, supply-side paradigm where grid operators treated demand as passive and inflexible. This supply-side bias persists in institutional arrangements and market design, preventing demand-side capacity from competing fairly with supply-side resources. While always problematic, this imbalance grows more consequential as variable renewables dominate supply.

Flexible demand enables more efficient market operation. Instead of relying solely on expensive peaking generation or transmission infrastructure to manage peak demand or renewable fluctuations, flexible demand can shift or reduce consumption in response to prices or system needs, and should in turn provide a reward for participating households and businesses.

System-wide benefits include:

- Improved capital efficiency through better utilisation of new and existing infrastructure (including networks);
- Reduced operating costs by decreasing reliance on costly fuel-based peaking generation, and
- Enhanced competition as demand resources compete with traditional generation in energy, ancillary services and other markets.

Collectively, efficient integration and use of demand-side resources reduces overall system costs passed to consumers.

In fully developed markets the supply and demand side submit bids and offers, allowing them to interact dynamically and on equal terms. Likewise, enabling demand-side resources to provide network and ancillary services supports a more resilient and efficient grid. Internationally, reforms are moving in this direction. The 2024 European Union Electricity Market Design Reform (EU Directive 2024/1711 and accompanying Regulation) introduced a definition of flexibility as 'the ability of an electricity system to adjust to the variability of generation and consumption patterns and to grid availability, across relevant market timeframes'[1]. FERC Order No. 2222, issued by the United States Federal Energy Regulatory Commission (FERC), requires regional transmission organisations and independent system operators to enable DER aggregators to participate alongside traditional generators in wholesale electricity markets, with a minimum bid size of 100kW.

The NEM Review presents a timely opportunity to address longstanding market distortions and bring the NEM in line with evolving global best practice.

1.3 The centrality of spot markets for derivatives and long-term contracting

A well-functioning electricity spot market is foundational to the success of derivatives and longer-term contracting arrangements. The spot market provides the transparent, granular price signals that underpin investment decisions, inform risk management strategies and shape contract terms. The lack of credible and efficient spot price formation undermines participants' ability to hedge future exposures or enter into financially viable long-term agreements such as power purchase agreements (PPAs), contracts-for-difference (CfDs) or capacity contracts.

Spot market outcomes form the reference point for most hedging products—both exchange-traded and over-the-counter. The prices constitute the references against which other medium- and long-term prices are set, and they motivate participants both in the short and long run[2]. If these prices are distorted, volatile in unpredictable ways, or poorly reflective of underlying system conditions, they increase the risk premium in derivatives markets and discourage participation. In systems with high levels of variable renewable energy, where price volatility is rising and expecting to rise, contract mechanisms are essential to managing both operational and investment risks.

A failure to integrate the demand side appropriately into wholesale spot markets, results in the demand side being largely absent in hedging and contracting strategies, which flows through to a lack of investment into these resources.

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1 Regulation (EU) 2024/1747 of the European Parliament and of the Council of 13 June 2024 Amending Regulations (EU) 2019/942 and (EU) 2019/943 as Regards Improving the Union's Electricity Market Design (Text with EEA Relevance) (2024). http://data.europa.eu/eli/reg/2024/1747/oj/eng.

2 IEA. 2016. Re-Powering Markets: Market Design and Regulation during the Transition to Low-Carbon Power Systems. Internation Energy Agency. https://www.iea.org/reports/re-powering-markets.

2. Spot market – short term market

2.1 International scan and best practice

This section summarises international practice and emerging design principles for integrating demand-side capacity—including aggregated distributed energy resources—into electricity markets on a level playing field with firmed renewable generation and storage. Features of market access for aggregated DER and demand-side resources across a selection of jurisdictions are compared, and the results of this comparison are combined with a selected literature review to identify common elements of international best practice. Table 1 summarises market access for aggregated DER and the demand side in Europe, the United States, New Zealand and Australia.

Generally speaking, European markets have adopted the most sophisticated frameworks, with France's NEBEF mechanism and Germany's balancing market access representing mature implementations dating from 2014-2016. North American markets show variable wholesale integration through FERC Order 2222 and established ISO programs.

Across these jurisdictions, there is a shift towards technology-neutral, performance-based models. Rather than defining participation by resource type, these models focus on the ability of a resource to deliver measurable services. Aggregator-enabled participation emerges as the dominant model, with virtually all active markets permitting third-party aggregation, though licensing and operational requirements vary significantly.

Some systems, like the New York Independent System Operator (NYISO), have adopted dual participation models, allowing DER to engage in both economic and reliability-based programs. Meanwhile, local flexibility markets, such as those in Great Britain, are gaining traction as a way to address distribution-level needs and value local DER capabilities.

Table 1: Comparison of market access for aggregated DER and demand-side resources across case study jurisdictions

Jurisdiction	Market Types	Minimum Size	Status	Market access details
European Union	Wholesale, Balancing, Network Support	100kW required from 2024, however implementation varies	Varies by member state	Legal framework established but implementation varies; Only France has independent aggregators with access to all markets; Distribution System Operators (DSOs) required to procure flexibility services. Demand response is available to small end-users in 22 out of 26 Member States, with independent aggregators recognised in the national legislation of 19 Member States.
France	Wholesale (NEBEF), Balancing, Capacity Mechanism	100 kW minimum load reduction capacity for direct participation	Active since 2014	NEBEF mechanism allows third-party aggregators to offer demand response services in wholesale power markets. Demand response participates in primary and secondary reserves since 2014-2016, with approximately 140 MW in primary reserve as of 2018. Capacity mechanism operational since 2017 with both explicit and implicit demand response participation.
Spain	Wholesale, Demand Response Balancing Service	1 MW minimum demand requirement (reducing to 0.1 MW through aggregation from 2026)	Active with expanding capacity	The Spanish transmission system operator (TSO) runs a demand response service auction process. The second auction secured demand response capacity of 609 MW for 2024, representing 23% increase from first auction. Third auction allocated 1,148 MW for 2025, an 89% increase. Service requires 12.5-minute notice (reduced from 15 minutes) for 1-2 hour activation periods. Proposed changes include semesterly auctions (replacing yearly), aggregation from 2026, and alignment with mFRR balancing market standards.
Italy	Ancillary Services Market (ASM), Capacity Market	10 MVA for mandatory ASM participation	Active with significant participation	More than 1.3 GW of demand side response, storage and small renewable energy plants qualified to ASM as ‘mixed virtual power plants’ as of 2020. Capacity Market implemented via reliability options following European Commission approval in 2018-2019.

Jurisdiction	Market Types	Minimum Size	Status	Market access details
Austria	Balancing (aFRR, mFRR), Demand-Side Response Electricity Saving Product	1 MW minimum bid size for balancing; 2 MWh minimum reduction capacity for demand response	Active markets with emergency demand response	Electricity Consumption Reduction Act (SVRG) enables consumers to reduce/shift consumption during peak periods (8-12 am, 5-7 pm). Daily auctions for balancing capacity in six 4-hour blocks. Up to €100 million available for demand response through March 2023. Pay-as-bid mechanism for both capacity and energy pricing.
Netherlands	Balancing, Industrial Demand Response	Not specified in current framework	Limited participation with expansion planned	TenneT estimates 1.7 GW of flexible capacity from industrial demand response by 2030. Current deployment limited due to lack of smart appliance control requirements. TNO research indicates significant potential of 40 TWh flexibility by 2050, primarily from power-to-hydrogen and electric vehicles.
Germany	Balancing Markets, limited wholesale market access	1 MW for FCR; 1 MW for aFRR/mFRR	Mixed access with ongoing reforms	Balancing markets open to demand response both individually and via aggregators. Automated demand response systems represent the fastest growing segment. Multiple TSOs coordinate through German Grid Control Cooperation (GCC). Local flexibility markets being tested in Energy-Flexible Model Region Augsburg
Great Britain	Wholesale, Balancing, Distribution Flexibility	1MW for most markets, 0.1MW for wholesale, 50kW for distribution network flexibility	Active markets	Virtual Lead Parties (VLPs) can access most markets; 15 VLPs participating in the Balancing Mechanism currently; Distribution flexibility services had 2.4GW contracted for 2023-24; Demand Flexibility Service for winter peaks; Elexon as Market Facilitator from 2024

Jurisdiction	Market Types	Minimum Size	Status	Market access details

US Federal (FERC 2222)	Capacity, Wholesale, Ancillary services markets	100 kW		FERC Order No. 2222 requires regional transmission organisations and independent system operators to enable DER aggregator participation in wholesale electricity markets from 2024. Implementation varies by ISO/RTO with consideration for locational, sizing, and data requirements.
US - California (CAISO)	Wholesale, Emergency Reserves, Demand Side Grid Support (DSGS)	100kW (After FERC Order 2222)	Four program options	Demand Side Grid Support Program: Emergency dispatch; Market-integrated demand response; Storage virtual power plant pilot; Emergency load flexibility VPP pilot (being introduced). Over 265,000 participants and 515MW enrolled. Program operates May-October during extreme events. Virtual power plant activated 16 times in 2024 season during four heatwaves.
US - Hawaii	Utility Programs, Emergency Demand Response	No wholesale market	Three participation models	Direct pricing programs; Utility procurement through aggregators; Utility 'Bring Your Own Device' programs; No wholesale market due to small system size Emergency demand response includes scheduled dispatch program requiring 10-year commitment with 2-hour daily dispatch during peak periods. Fast DR program expanded to full capacity.
US - Texas - ERCOT	Aggregate Distributed Energy Resource (ADER) Pilot	No specified minimum (pilot program)	Pilot program evaluation phase	ADER pilot project evaluates participation of aggregated distributed energy resources in ERCOT wholesale markets. Resources consist of multiple individual metered sites connected at distribution level with ability to respond to ERCOT dispatch instructions. Pilot established through Public Utility Commission of Texas Project No. 53911.

Jurisdiction	**Market Types**	**Minimum Size**	**Status**	**Market access details**

Jurisdiction	Market Types	Minimum Size	Status	Market access details
US - PJM[3]	Wholesale, Energy Markets, Capacity Markets (RPM), Ancillary Services	No minimum for Economic DR; varies by program	Active markets	Two broad categories: Load Management (Pre-Emergency and Emergency DR) with capacity market commitments, and Economic DR for energy/ancillary services markets. Curtailment Service Providers (CSPs) act as aggregators. Economic DR dispatched when offer price less than marginal price. Load Management requires commitment to reduce load when required or receive financial penalty.
US - NYISO	Energy, Ancillary Services, Installed Capacity, Emergency Programs	100 kW minimum for most programs; 1 MW for DADRP and DSASP	Active with multiple program options	Four main programs: Emergency Demand Response Program (EDRP - voluntary), ICAP Special Case Resources (SCR - mandatory), Day Ahead Demand Response Program (DADRP), and Demand Side Ancillary Service Program (DSASP). Individual Demand Side Resources minimum 10 kW within aggregations. Can participate in one reliability-based and one economic-based program simultaneously.
US – Midcontinent Independent System Operator (MISO)	Energy (Economic DR), Operating Reserves, Emergency, Planning Resources (LMR)	100 kW for Emergency DR and LMR; 1 MW for Economic DR and Operating Reserves	Active across multiple markets	Three types of participants: Load Serving Entities, Aggregators of Retail Customers (ARCs), and end-use customers with market participant status. LMR program requires year-round 24x7 availability with historically 0-3 dispatches per year. Economic DRR can provide energy and/or operating reserves simultaneously.

[3] The PJM Interconnection coordinates the movement of electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia- https://www.pjm.com/about-pjm/who-we-are/territory-served.

US - ISO-New England (ISO NE)	Energy, Reserves, Forward Capacity Market	100 kW minimum for Demand Response Resources (DRR); 10 kW minimum for individual Demand Response Assets (DRA)	Active markets	Price-responsive demand model allows DRRs to bid into day-ahead and real-time energy markets, 30-minute operating reserves, and 10-minute spinning/non-spinning reserves. DRAs ≥5 MW must be mapped to own DRR. Technology-agnostic aggregations allowed within same Aggregation Zone.
US - Southwest Power Pool (SPP)	Load Modifying Resources (LMR), Emergency	100 kW minimum obligation across zonal portfolio	Active with expansion planned	Year-round 24x7 program with up to 16 dispatches per year (historically 0-3). 4-hour maximum dispatch duration with 6 hours to 30 minutes notification. No capacity market - resources receive Zonal Resource Credits (ZRCs). Developing comprehensive demand response policy to address shrinking reserves.
New Zealand	Wholesale, Ancillary Services	1-10MW for Dispatch Notification Load	Limited participation	Dispatch Notification Load for small aggregated resources; Difference Bids for baseline deviation; Fast and Sustained Instantaneous Reserve; Distribution flexibility in early stages
Australia (NEM)	Contingency, FCAS, Emergency Reserve, Demand Response Mechanism	1MW for most markets, 10MW for RERT	Active with reforms planned	Contingency FCAS markets (8 markets, categorised by the speed of response required (Very Fast, Fast, Slow, and Delayed) for both raise and lower services); Demand Response Mechanism (large C&I businesses only); Emergency reserve (RERT) procurement on 3 timeframes by the market operator; Distribution network support services (trials only); Wholesale energy markets (voluntary scheduling from late 2026);

This international scan in combination with selected literature[4,5,6,7] highlights common and pertinent features of effective integration of demand side resources:

- **Low minimum thresholds** (100kW or less) are common to support aggregated DER access to markets. By reducing these limits, markets open the door to smaller aggregators enhancing competition.
    - Participation thresholds set at the scale of large industrial loads or traditional generators create barriers for households and small business participation.
- **Coordination mechanisms** between system operators, networks and DER are common and necessary for scheduling, visibility and operational integration within the physical limits of the network and system. These mechanisms can be a price-based or contractual mechanisms and can be undertaken at different levels of the system.
    - Aggregation models are currently essential for participation by small-scale resources in energy markets and are a common approach to coordination. Third-party aggregators offer aggregated DER into markets in a form that system operators can forecast, dispatch and settle.
- **Standardised, transparent and fit-for-purpose baseline methodologies** are widely used to support demand response (DR) participation. These baselines estimate what energy usage would have occurred in the absence of a market signal, forming the basis for settlement and verifying performance (see section below on this). Inaccurate or opaque baseline methods can erode trust and reduce the effectiveness of DR programs.
- **Locational pricing** is considered important to provide clearer and more granular price signals.
    - Nodal pricing—used in markets such as PJM and CAISO—more accurately reflects system constraints and congestion, supporting more efficient investment and operational decisions, including the optimal siting of DER.
- **Capacity markets** can offer an additional revenue stream for DER where implemented.
    - However, they also introduce challenges, such as complex qualification criteria, performance obligations and the risk of misalignment with energy market dispatch. Where capacity and energy market incentives are not well-integrated, they can create distortions or disincentives for DER.

2.2 The importance of aggregators

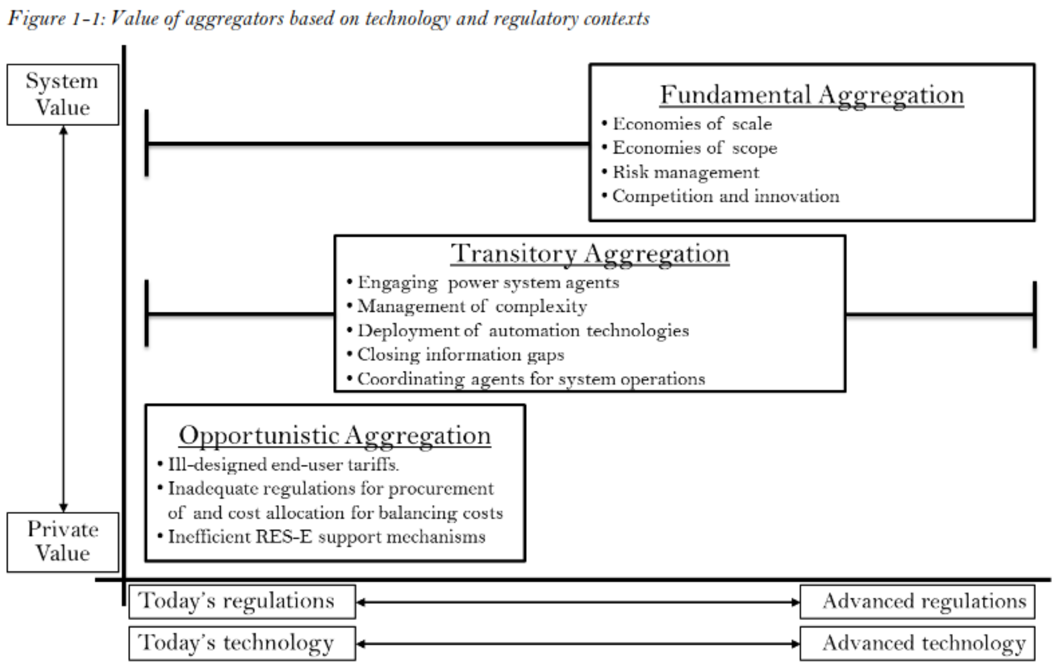
Our analysis of these markets has identified aggregation as a common and essential feature that warrants further attention. At a high level, an aggregator is an entity that coordinates and manages the participation of multiple distributed energy resources and demand response assets—such as rooftop solar, batteries, flexible industrial loads, and smart appliances—so they can act collectively in energy markets or provide services to the power system. Aggregators create and manage portfolios of smaller, often customer-owned resources with sufficient scale, controllability, and flexibility to bid into wholesale markets, deliver network services, or

[4] Horowitz, Kelsey, Zac Peterson, Michael Coddington, et al. 2019. An Overview of Distributed Energy Resource (DER) Interconnection: Current Practices and Emerging Solutions. NREL/TP-6A20-72102. National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy19osti/72102.pdf.
[5] ACER. 2025. Unlocking Flexibility: No-Regret Actions to Remove Barriers to Demand Response. European Union Agency for the Cooperation of Energy Regulators. https://www.acer.europa.eu/news/unlocking-flexibility-acers-12-no-regret-actions-remove-barriers-demand-response.
[6] IEA. 2022. Steering Electricity Markets Towards a Rapid Decarbonisation. International Energy Agency. https://www.iea.org/reports/steering-electricity-markets-towards-a-rapid-decarbonisation.
[7] IEA. 2022. Unlocking the Potential of Distributed Energy Resources. International Energy Agency. https://www.iea.org/reports/unlocking-the-potential-of-distributed-energy-resources.

respond to system needs. They act as an intermediary between customers and market or system operators, handling complex tasks like scheduling, forecasting, compliance, and risk management.

An MIT report on *The Value of Aggregators in Electricity Systems* (Burger et al, 2016)[8] proposes that the technology and regulatory context shapes the level of value that aggregators deliver, ranging from opportunistic (relatively low value) to fundamental (high value) —see Figure 1.

Figure 1: Theoretical value of aggregators based on technology and regulatory context



Fundamental value arises from the inherent economic advantages of aggregation. Economies of scale exist as aggregators reduce per-unit costs by spreading fixed expenses, such as ICT infrastructure, compliance and market participation costs across many DER. For example, a single aggregator managing 100,000 DER incurs lower transaction costs than individual DER participating separately.

Economies of scope exist as aggregators bundle multiple services (e.g. energy, emergency reserves, frequency response) using shared technologies and customer relationships. While they note bundling enables cross-sector synergies such as combining energy with telecom services, that is probably less important in the Australian context than value stacking energy services.

Aggregators manage risk—hedging price volatility and uncertainty for small DER owners. This is vital when volatility is large, as is currently the case in the NEM. With changes in market design, and improvements in forecasting and scheduling by the system operator, this management of uncertainty may decrease in value. Advances in automation such as AI-driven Home Energy Management Systems (HEMS)/EMS are likely to reduce reliance on aggregators value stacking and risk management over time.

[8] Burger, S., Chaves-Ávila, J. P., Batlle, C., & Pérez-Arriaga, I. J. (2016). The Value of Aggregators in Electricity Systems (CEEPR WP 2016-001). MIT Center for Energy and Environmental Policy Research. https://energy.mit.edu/wp-content/uploads/2016/01/CEEPR_WP_2016-001.pdf

Burger et al (2016) argue that ‘traditional anti-competitive flaws such as unilateral market power, vertical integration, and barriers to entry or expansion can be mitigated through DER integration[9]’. Further, competing aggregators can drive innovation in DER deployment and customer engagement. For example, firms like Opower and EnerNOC developed automated demand response tools. However, the extent of innovation compared with the costs to consumers is unclear at this point.

Transitory value emerges from temporary gaps in technology, regulation or market design. Aggregators relay granular price signals to DER owners who lack direct market access, as is the case currently with FCAS markets in the NEM. Aggregators simplify compliance with market rules, such as bid formatting and telemetry standards and coordinate DER responses. This is critical for fast-responding services like Fast Frequency Response (FFR).

Small financial incentives often fail to motivate individual action. Aggregators can automate participation and aggregate small savings into meaningful system-wide impacts, as has historically been done by Distribution Network System Providers (DNSPs) with off-peak hot water. In 2016, Opower managed an estimated 4.5 GW of peak reduction in the US.

Opportunistic aggregation can exploit market design inefficiencies, creating private gains at the system’s expense. If there are penalties for lack of response in the provision of balancing services, aggregation may reduce these penalties due to the potential to draw upon multiple resources with different costs.

Some markets (e.g. MISO and NYISO) require symmetrical products for upward and downward regulation or reserves. A wind farm, for example, unable to meet its schedule might offset deficits with aggregation, even if the latter’s marginal cost exceeds system efficiency. Burger et al suggest that ‘as demand becomes more price-responsive, it should be subjected to the same imbalance prices as supply’.

The MIT paper cites a range of inefficient and inconsistent tariffs which create opportunistic aggregations. For example, zonal pricing for loads with nodal prices for generation in CAISO allows aggregators to profit from spatial price differences without relieving congestion. For example, increasing load in a high-price zone to boost demand while paying dampened zonal rates for the increased demand. Peak demand charges have the potential to over-incentivise behind the meter (BTM) DER investment or encourage aggregation for loads offset by time to create private value by smoothing peaks across customers while not decreasing network costs.

The authors conclude aggregators play a vital role in integrating DER, but require careful regulation to optimise system value, including consideration of:

- Fundamental Value should be encouraged through standardised market products and neutral access rules.
- Transitory Value necessitates temporary support for automation technologies and consumer engagement tools.
- Opportunistic Value must be mitigated via reforms to imbalance pricing, tariff design, and locational signals.

[9] Burger, S., Chaves-Ávila, J. P., Batlle, C., & Pérez-Arriaga, I. J. (2016). The Value of Aggregators in Electricity Systems (CEEPR WP 2016-001). MIT Center for Energy and Environmental Policy Research. https://energy.mit.edu/wp-content/uploads/2016/01/CEEPR_WP_2016-001.pdf

2.3 Principles

Emerging from this international analysis, we have derived four principles for integrating the demand side into the spot-market:

2.3.1. Granular price signals and stackable value

To enable optimal dispatch and investment in DER, it is essential that price signals reflect the real conditions of the power system—both temporally and spatially. Granular pricing, including locational signals, helps direct DER investment and operation to where it provides the greatest value[10]. Even in the absence of broader structural reforms, improving locational pricing can unlock substantial system benefits and reduce inefficiencies[11].

A critical enabler of efficient integration is the ability for DER to stack value across different services—such as energy, capacity, essential system services, and network support—based on when and where they operate. International experience, for example in Great Britain, highlights the importance of explicitly supporting value stacking through clear rules, co-optimisation mechanisms and differentiated definitions. Without these, DER are often excluded from multiple revenue streams, reducing their viability despite their potential contribution to system efficiency and resilience. Building value stacking into future market reforms from the outset can avoid costly retrofits and regulatory workarounds.

2.3.2 Open market access and equal treatment

Ensuring fair, open and non-discriminatory access to all markets and regulatory procurement processes is fundamental for unlocking the full value of aggregated DER. This includes enabling participation across all relevant services: energy, demand response, essential system services, emergency procurement (such as RERT) and network support.

Current arrangements in the NEM create artificial thresholds that prevent a significant share of demand-side potential from participating. These restrictions not only limit competition but also reduce the system's ability to access flexible, distributed resources.

International jurisdictions have moved decisively to reduce participation thresholds. FERC Order 2222 in the US requires wholesale markets to accept aggregations as small as 100 kW, while the EU and GB are pushing thresholds down to 50–100kW. By contrast, Australia maintains a 1MW threshold in all markets and 10 MW for RERT—substantially limiting access and competition.

Open market access improvements for Australia include:

- Lower aggregation thresholds,
- Non-discriminatory technical standards, and
- Interoperable communication protocols (these last two are discussed in the section on enablers).

Fair compensation is critical. Aggregated DER should be paid for the full suite of services they provide, with prices that reflect both system-wide and locational value. This includes access to

[10] IEA. 2022. Unlocking the Potential of Distributed Energy Resources. Internation Energy Agency. https://www.iea.org/reports/unlocking-the-potential-of-distributed-energy-resources.
[11] IEA. 2022. Steering Electricity Markets Towards a Rapid Decarbonisation. Internation Energy Agency. https://www.iea.org/reports/steering-electricity-markets-towards-a-rapid-decarbonisation.

multiple revenue streams (value stacking as mentioned above) and protection from discriminatory penalty regimes or liabilities not applied to traditional providers.

2.3.3 Clear aggregator role and support for independent entry

A clear and supportive framework for aggregators is essential to stimulate innovation and unlock demand-side potential. Aggregators -particularly independent ones - bring new business models and customer engagement strategies that complement, rather than replicate, the roles of retailers or networks.

2.3.4 Data visibility and flows

There is significant value in demand-side resources being visible to different parts of the system at different timescales. Without sufficient visibility, demand-side flexibility cannot be drawn upon for dispatch, contingency response or planning activities which can undermine the case for deeper integration of the demand-side. However, the details about what level of visibility is needed by which actors is yet to be resolved.

2.4 Discussion: current directions and reforms

The NEM review panel has indicated that it believes the spot market remains largely efficient for dispatch and is a strength of the NEM's market design. Early guidance from the panel suggests that the core spot market framework will remain, while introducing incremental reforms. These may include encouraging more resources to become visible, and the panel has indicated that locational pricing will not be considered.

This section focuses on two wholesale market oriented reforms that are particularly relevant to increasing demand-side participation in the spot market: Integrating price-responsive resources into the NEM (IPRR) with the creation of a new ‘dispatch mode’ and the review of the Wholesale Demand Response Mechanism (WDRM).

We discuss their limits and other challenges, then follow with recommendations, drawing on the principles outlined above. Our recommendations aim to facilitate and benefit all consumer types—those who want direct spot exposure, participation in aggregation (a VPP) or no participation. We assume that consumers have the choice about whether or not to provide their flexible demand to the market, whether that is through their retailer, an independent aggregator, DNSP or otherwise and that this participation ranges from direct response to fully automated (including machine-to-machine tariffs).

Integrating price-responsive resources and flexible trading relationships

The Integrating price-responsive resources into the NEM (IPRR) rule change enables aggregated consumer energy resources and price-responsive loads to be scheduled and dispatched in the NEM. This reform plans to enable these ‘Voluntarily Scheduled Resources’ (VSR) to participate either individually or be aggregated to directly respond to spot prices and AEMO dispatch instructions. The AEMC has claimed this process will not rely on baseline methodologies, in contrast to the WDRM (discussed below) and will use a new, yet to be detailed ‘dispatch mode’.

The parallel and intersecting Flexible Trading Relationships (FTR) rule change allows for the splitting of resources at customers premises, via the introduction of ‘secondary settlement points’ most likely splitting between flexible and inflexible loads. This rule was proposed to allow customers to more easily gain value from their flexible resources through participation in wholesale and ancillary services markets, including via the IPPR, and potentially with different market participants.

Participation in the IPPR is voluntary and is supported by a time-limited incentive to encourage early uptake. To boost early adoption, AEMO will run tenders (2026–2031) offering time-limited payments to participants. These payments are capped at $50 million and recovered via market charges.

IPRR is intended to incentivise and increase visibility of daily shifting and shaping activities, and support different business models to those supported by WDRM. While the mechanism is still in an implementation phase, the design has already raised a number of concerns with demand-side and consumer stakeholders.

First, small customers[12] are excluded from contracting flexible loads with third parties. While secondary settlement points can be created for small-customers, customers must retain a singular Financially Responsible Market Participant (FRMP) which is also the retailer in the case of small loads. That is, secondary settlement points can be created for small customers, but this settlement point(s) is locked into to the same FRMP (and therefore retailer) that serves the consumer's overall demand. There is no opportunity for small customers to contract with another party, including an independent aggregator, whereas large customers can contract secondary settlement points to a different FRMP.

By requiring that Voluntarily Scheduled Resource Providers (VSRPs) are FRMPs, wholesale market participation for DER or aggregated DER will effectively only be available to retailers, excluding independent aggregators. This will result in limited competition and innovation in products and services for small customers. In their determination[13], the AEMC concluded that further work was required to progress the option of allowing small users to contract with multiple FRMPs, due to the potential for this to create new or exacerbate existing complications. Specifically, the AEMC suggested more work needed to be done on the National Energy Customer Framework (NECF) to both protect consumers and enable further innovation and competition. Importantly, the AEMC indicated that these consumer protection issues could be addressed, and that further changes could be made to FTR and therefore IPRR in the future.

Second, it is unclear how consumers will be incentivised and fairly remunerated in the absence of codified baseline methodologies. While the IPRR approach avoids using centrally determined or formal baselines, it does not eliminate the need for baselining altogether. Instead, it essentially shifts the responsibility for establishing and applying baselines to the FRMP that is responsible for the secondary settlement point. Without a robust approach to baseline measurement with appropriate accountabilities and validation, there is no way to calculate the consumer's contribution or payment which results in a lack of transparency for all parties involved. Moreover, the incentives for the FRMP (which is also the retailer at the in the case of small loads) are not necessarily well aligned with developing (or using) methods that are in the interests of the consumer or the system more broadly.

Third, minimum registration thresholds and minimum bid sizes continue to be set artificially high at 1MW[14], limiting smaller aggregators from participating because of the cost involved in identifying and recruiting the required number of customers. In practice, this limits participation to larger participants, like established retailers who can draw on their existing customer base. This limit is discussed further in the recommendation section.

[12] The thresholds to be considered as a large electricity customer are set by jurisdictions and vary, with a range of 100 MWh – 160 MWh per year.
[13] AEMC. 2024. Unlocking CER Benefits through Flexible Trading, Rule Determination. No. ERC0346. Australian Energy
[14] In June 2025 AEMO proposed reducing the minimum participation size for Voluntary Scheduled resources from 5 MW to 1 MW.

While the IPRR reform is still being implemented, it represents, at best, a partial step toward more active and efficient demand-side participation in the NEM. Given current market arrangements, most retailers do not have a strong incentive to manage household demand through IPRR, and independent aggregators are excluded, limiting competitive pressure. The demand side impacts of these reforms appear compromised, raising questions about its utility and cost-effectiveness.

The wholesale demand response mechanism

The Wholesale Demand Response Mechanism (WDRM) allows third-party demand response providers to participate in the NEM by aggregating flexible loads from large commercial and industrial energy users. The AEMC is currently reviewing the WDRM to assess whether it should be retained, reformed, or phased out, considering its costs, benefits, and effectiveness since its introduction. A recent draft report from the AEMC acknowledges that the WDRM performs a unique and essential role and indicates a commitment to retain and improve the mechanism.[15]

The review occurs in the context of the IPRR rule change suggesting demand-side resources can be scheduled and dispatched without relying on baseline calculations. The uptake of the WDRM has been limited: only two providers registered 146MW[16] of response capacity, with minimal dispatch to date.

There is a strong case that this limited uptake is related to the specific limitations of the WDRM's participation requirements and parameters. The WDRM limits participation to large business customers (>100MWh or, in Victoria and South Australia, >160MWh and Tasmania, >150MWh) with highly predictable demand profiles (baselining is discussed further below). Aggregated household DER are not able to participate.

Small business customer National Metering Identifiers (NMIs) can be classified and aggregated as Wholesale Demand Response Units (WDRUs) where they have a National Energy Retail Rules (NERR) agreement with their retailer to aggregate its premises' loads. There is no lower size limit for individual loads within a WDRM aggregation so long as they are classed as 'large' customers (jurisdiction dependent). However, the minimum dispatchable unit and bid increment size (either a single NMI or aggregation) is also 1MW (this is discussed further in the recommendations section).

The critical issue of baselining

A requirement for near static baselines for participation in the WDRM is an even more significant barrier to participation. AEMO's baselining methods for the WDRM are overly restrictive, with some estimating they exclude 80-95% of commercial and industrial loads because their load types are not flat and predictable.[17] Most commercial and industrial loads are temperature sensitive or variable, which means facilities like metal recycling plants and smelters are effectively ineligible or have no incentive to participate because their baselines are adjusted downwards due to normal operational fluctuations. Demand-side and consumer stakeholders have regularly raised issues with current baselines, the need for more baselines, and the process for developing new ones.

International experience provides guidance on how baselining approaches could be improved. Many markets and mechanisms that allow demand-side participation use baseline methods to

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[15] AEMC. 2025. Draft Report - Review of the Wholesale Demand Response Mechanism. No. EPR0099. Australian Energy Market Commission. https://www.aemc.gov.au/market-reviews-advice/review-wholesale-demand-response-mechanism.
[16] NEM Registrations and Exemptions List, (July 2025). At the time the WDRM review was launched, 74MW were registered.
[17] AEMO. (2021). Phase 2 Baseline Methodology and Participant Testing Wholesale Demand Response Mechanism Baseline Methodology Testing and Metrics. March 2021

calculate actual demand reduction, with settlements based on real-time performance. In the United States, ISO New England (ISO-NE) requires five-minute load interval reporting, while PJM settles at locational marginal prices for verified reductions. Mandatory emergency/reliability participation (responding to system operator instructions) may also be possible or required.[18]

There appear to be five primary baseline method types used across global energy markets:

1. Meter Before-Meter After (MBMA): Establishes a flat baseline using pre-activation consumption levels, widely used for real-time dispatch conditions and short utilisation periods. This methodology requires relatively flat load profiles and sub-metering at the distributed energy resource asset level.
2. Historical Baseline Methods: Calculate baselines using historical consumption data from similar time periods, with the most common variant being ‘X of Y’ methodologies where X days are selected from the most recent Y eligible days. Examples include California's ‘10 of 10’ method, Ontario's ‘High 15 of 20’ and PJM’s ‘4 of 5’ approach.
3. Declarative Baselines: Require market participants to determine and submit their baseline ahead of real-time operation. Common in Europe for products requiring rapid response, such as automatic Frequency Restoration Reserves (aFRR) requiring one-minute advance submission in Belgium's Elia system.
4. Regression-Based Methods: Employ statistical models incorporating weather variables, calendar variables and daylight variables to predict consumption patterns. ERCOT utilises statistical multivariate regression approaches using formulas such as kWd,h,int = F(Weatherd, Calendard, Daylightd) - a mathematical model for estimating or forecasting electricity demand (measured in kilowatts, kW) for a specific day (d), hour (h), and interval (int) within that hour. The function F represents a mapping or calculation that depends on three main factors: the weather conditions, the calendar characteristics of the day and the daylight or solar variables. Similar approaches are used by AEMO in its demand forecasting methodology.[19]
5. Control Group/Peer Group: Calculate baselines using measurements from similar customers who do not participate in flexibility services, though this approach has limited application due to data availability constraints.[20]

Different electricity market products require different baseline approaches, with short-duration, fast-response services (FCR, aFRR) preferring MBMA methodologies or declarative baselines, while longer-duration products (adequacy, day-ahead markets) favour historical or regression baseline approaches. For example, Belgium offers multiple methods tailored to specific services: High X of Y for strategic reserves and day-ahead markets, Last Quarter Hour for manual Frequency Restoration Reserves, and declarative baselines for automatic reserves. ERCOT provides seven distinct methodologies allowing demand response resources to select approaches most appropriate for their load characteristics. Markets increasingly incorporate weather sensitivity considerations, with ERCOT determining that event-day adjustments improve accuracy for all methodologies except Meter Before-Meter After approaches.

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[18] Oakley Greenwood. (2019, September). Baselining: ARENA–AEMO Demand Response RERT Trial. Australian Renewable Energy Agency. https://arena.gov.au/assets/2019/09/baselining-arena-aemo-demand-response-rert-trial.pdf

[19] Australian Energy Market Operator. (2024, August). Electricity demand forecasting methodology (Version 1.4). https://www.aer.gov.au/system/files/2024-08/AEMO%20-%20Electricity%20Demand%20Forecasting%20Methodology%20-%20August%202024.pdf

[20] Elia. (2021, September 24). Baseline methodology assessment: Performance of baseline methodologies and opportunities for alternative baseline methodologies [Report]. https://ppl-ai-file-upload.s3.amazonaws.com/web/direct-files/attachments/46881831/dc048fa6-6f40-475a-b2c5-88bb8d12a3a5/Belgium-baselining.pdf

The European industry body for demand flexibility, SmartEn recommends small numbers of standardised baseline methodologies to reduce complexity while maintaining accuracy, and advocates for standardised calculation formulas to facilitate cross-border DR participation.

Baselines are evolving as technology improves including by incorporating artificial intelligence and machine learning approaches to enhance baseline accuracy, particularly for complex load patterns involving distributed energy resources, electric vehicles, and flexible industrial processes.[21] Machine learning algorithms can process data from smart meters and IoT devices, improving demand response dispatch decisions by 15–25% compared to traditional rule-based systems.[22] In addition, there is progress toward real-time baseline adjustments using current weather conditions and consumption patterns.[23] Belgium's declarative methodology requires one-minute advance baseline submission representing the cutting edge of rapid adaptation capabilities.

In addition, the technology in buildings and devices is becoming more sophisticated. Building automation systems (BAS) and energy management systems (EMS) can automatically adjust setpoints, cycle equipment, and shed loads in response to market signals or system operator instructions, all while maintaining accurate baselines for settlement. IoT devices (smart thermostats, water heaters, EV chargers, battery storage) create a network of intelligent endpoints that can be monitored and controlled with high granularity. Standardised communication protocols (e.g. IEEE 2030.5, OpenADR, Matter) facilitate automated participation in demand response, with minimal consumer intervention.

2.5 Recommendations

To support fair competition and dynamic market development, the following actions are recommended.

2.5.1 Update existing systems (including NEMDE) to permit aggregated loads of 100kW or less to participate

Current systems used by the NEM, particularly the NEMDE (NEM Dispatch Engine), impose artificial thresholds—such as minimum registration and bid sizes—that exclude much of the demand-side from participating. These restrictions not only limit competition, but also prevent the system from accessing the full value of flexible, distributed resources. AEMO acknowledges that a 1 MW increment may pose a barrier to the participation of small aggregators. The minimum viable bid size should be investigated and it should be reduced to 100kW or less in line with international best practice.

AEMO currently supports maintaining the 1 MW limit, arguing that reducing the increment size could have significant implications for the operation of NEMDE. This includes longer solution times due to increased dispatchable unit identifier (DUID) processing and granularity, and potentially costly system upgrades to manage enhanced data granularity and monitoring requirements. In the context of broader critiques of the NEMDE[24], and deterministic linear

[21] C4NET. (2022, November). Machine Learning in Demand Response: White Paper [White paper]. https://c4net.com.au/wp-content/uploads/2022/11/Machine-Learning-in-Demand-Response-White-Paper-Project-69.pdf

[22] Chakraborty, S., & Mondal, T. (2021). Application of machine learning in demand response: A comprehensive review. Energy and AI, 3, 100049.

[23] Op Elia. (2021, September 24). Baseline methodology assessment: Performance of baseline methodologies and opportunities for alternative baseline methodologies [Report]. https://ppl-ai-file-upload.s3.amazonaws.com/web/direct-files/attachments/46881831/dc048fa6-6f40-475a-b2c5-88bb8d12a3a5/Belgium-baselining.pdf

[24] See chapter 6, "Improving the NEM Dispatch Engine (NEMDE)", Intelligent Energy Systems (2017) https://www.aemc.gov.au/sites/default/files/content/ebbd13b2-21de-4ec9-8293-034c19607ac7/RuleChange-Submission-ERC0201-Intelligent-Energy-Systems-Pty-Limited-160616.PDF

programming approach more generally, the inability to integrate DER represents an additional capability shortfall. Further investigation into the suitability of NEMDE for managing the energy system of the future is warranted.

Emerging approaches, like stochastic optimisation, are potentially also worth further investigation. The variability introduced by renewable energy and distributed energy resources and associated market dynamics raises question of how to make optimal decisions under uncertainty, that linear deterministic models (like NEMDE) are not well suited to. Stochastic optimisation is an alternative that might be better suited to making optimal decisions under uncertainty[25.] While fully stochastic optimisation approaches have not yet been implemented in large grids[26], research suggest they present a promising alternative for power systems[27,28]

2.5.2 Support independent aggregators to participate in the spot market, through IPRR, via updates to the Flexible Trading Relationships rule.

The IPRR reforms do not offer access for third-party aggregators or small consumers outside existing retailer arrangements. Participation remains mediated through retailers, limiting opportunities for independent demand response service providers to operate on a level playing field. The recent Flexible Trading Relationships rule change does not address this problem, being constrained to C&I energy users only. Expanding the flexible trading relationship rule and households would allow equivalent access for third-party aggregators, as is possible with large users. As noted above, this may require parallel changes to consumer protection regulation.

2.5.3 Extend WDRM to small users and households

Small users, both households and businesses, should be able to participate in the WDRM. While the WDRM enables third-party aggregators to bid demand reductions directly into the wholesale market, it is currently only accessible to large users. Expanding participation to small users (and appropriate baselines) is important to enhance demand side participation in the NEM.

The IPRR and WDRM are designed for different purposes. The IPRR provides incentives for retailers[29] to voluntarily facilitate consumer participation whereas aggregators can participate in the WDRM through separate contracts with consumers. As such, the two mechanisms support different participation models and reflect different incentive structures, and it is important to both extend WDRM to small users, and separately to allow aggregation of small user loads in the IPRR.

2.5.4 Expand baselining methods in the WDRM

Aggregation-friendly baselines are important for enabling small-users and customers with multiple connections points to participate in the WDRM. More broadly, there is a need to expand baseline options for large-scale consumers as well. We suggest that baselining in future

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[25] For a detailed review of method of power system optimization under uncertainty, see Roald, Line A., et al. "Power Systems Optimization under Uncertainty: A Review of Methods and Applications." Electric Power Systems Research, vol. 214, Jan. 2023, p. 108725. DOI.org (Crossref), https://doi.org/10.1016/j.epsr.2022.108725.
[26] The valuation of reserves through an operating reserve demand curve (ORDC) in the ERCOT grid moves a little more toward stochastic approaches to dispatch. See Jacob Mays (2021) Quasi-Stochastic Electricity Markets. INFORMS Journal on Optimization 3(4):350-372 for a proposal of a more formal linkage to stochastic market outcomes.
[27] Morales, Juan M., Marco Zugno, Salvador Pineda, and Pierre Pinson. 2014. "Electricity Market Clearing with Improved Scheduling of Stochastic Production." European Journal of Operational Research 235 (3): 765–74. https://doi.org/10.1016/j.ejor.2013.11.013.
[28] Zavala, Victor M., Kibaek Kim, Mihai Anitescu, and John Birge. 2017. "A Stochastic Electricity Market Clearing Formulation with Consistent Pricing Properties." Operations Research 65 (3): 557–76. https://doi.org/10.1287/opre.2016.1576.
[29] In the case of small-scale customers

Australian energy markets uses the following four principles developed by industry to maximise confidence in this critical market[30]:

- Simplicity (practical implementation with proportionate effort),
- Accuracy (good representation of counterfactual behaviour),
- Integrity (restriction of gaming opportunities), and
- Replicability (verification capability for all relevant parties).

Streamlining and accelerating the addition and approval of new baselines is critical to ensure they can be developed and implemented in a timely and efficient manner.

[30] EnerNOC, Inc. (2009). Baseline methodologies for demand response programs: Best practices and lessons learned (White Paper). North American Energy Standards Board. https://www.naesb.org/pdf4/dsmee_group3_100809w3.pdf

3. Medium term derivatives markets

The development and use of forward and exchange-traded derivative products—whether over-the-counter (OTC) or through exchanges like the ASX—have historically been important for managing price risk in the National Electricity Market (NEM). These instruments, including fixed baseload and peak-load swaps and cap contracts, provide essential risk management for generators and retailers, helping them navigate volatile spot market conditions and plan investments. However, these products were designed in a different era – more tailored to the operational characteristics of coal, gas, and hydro generators, and a relatively predictable demand profile.

As the energy system transitions, the structural basis of the NEM's derivatives markets is therefore being challenged. For example, peak contracts have become far less common, reflecting changes to the traditional demand profile. While some innovation is emerging—such as the introduction of 'super peak' swaps and 'solar shape' contracts—these products remain supply-side focused. The 'super peak' products cater to high-demand, high-price periods but have mainly attracted participation from fast-responding generators like hydro and gas. The 'solar shape' swap enables sellers to hedge based on a generation profile aligned with solar output, which might particularly suit a specific technology class. Despite the potential for demand-side flexibility—such as industrial load curtailment, battery discharge, or aggregated residential demand response—to serve as natural counterparties to such contracts, these resources remain absent from derivatives markets innovation.

3.1 Principles

Several high-level principles are important for hedge market design in high variable renewable systems[31]. The following represent principles that are generally important but also have particular relevance to the demand-side and DER:

3.1.1 Transparency and competition

Exchange-traded products should be based on standard contracts, clear price signals, and allow participation by a wide range of market actors. Expanding participation in hedge markets improves competition, liquidity and efficiency of markets

3.1.2 Market liquidity through aggregation

Liquidity improves when demand and supply are aggregated across the market.

3.1.3 Neutral market architecture

Hedging products should not impede optimal dispatch and efficient market integration.

3.2 Discussion: current directions and reform

The NEM review panel has noted in public consultation that it views the derivatives markets as essential for enabling retailers and other participants to hedge price risks in a more volatile and

[31] ACER. 2023. "ACER Policy Paper on the Further Development of the EU Electricity Forward Market." European Union: European Union Agency for the Cooperation of Energy Regulators. https://acer.europa.eu/sites/default/files/documents/Position%20Papers/Electricity_Forward_Market_PolicyPaper.pdf.

weather-dependent system. However, liquidity is at risk due to increased variable renewable energy saturation and public underwriting mechanisms that divert capacity away from the market. Accessibility remains a barrier for smaller retailers, and contract innovation (e.g. for weather risk, time-of-day, or VRE shapes) is occurring too slowly and unevenly.

Early directions focus on improving market liquidity and accessibility. Options under consideration include extending price discovery, enhancing public exchange-traded products, and adapting lessons from previous liquidity obligations. While there is clear acknowledgment accessibility is an issue, there is no clear pathway to support smaller participants to effectively hedge and compete.

Improving liquidity is only useful if the underlying contract structures are fit for purpose. Further innovation in derivative structure is generally required. If contract structures continue to evolve without explicitly considering the needs and characteristics of demand-side resources, these resources risk being left out of contracting markets. This exclusion limits their ability to manage price risk and weakens their business case. Reform must go beyond spot price formation to consider how demand-side participation can be explicitly and effectively integrated into hedging and frameworks[32].

3.3 Recommendations

3.3.1 Develop standardised forward products or exchange-traded hedges that work for flexible demand aggregators and the demand-side more broadly.

Forward products need to support access for a wide range of market actors, not just large generators or utilities. Hedging contracts should be designed to enable independent aggregators to enter and operate without necessarily being tied to traditional retail portfolios or business models. This requires contract terms that are transparent, low-friction, and scalable, allowing aggregators to effectively manage risks.

In practice, this could mean different things to different demand-side business models. For example, it could mean ensuring new products that support peaking assets are also suitable for demand response providers through the WDRM. For business models better suited to participation in IPRR (for example flexible loads that might operate more frequently like batteries), this means products that reflect this emerging demand-side capability. The demand-side is the counterparty to supply side contracts, and yet most innovation in hedging products caters to the characteristics of supply, (for example through weather derivatives or benchmarking). Rather than impose particular contracting requirements, we suggest innovation in product design considers both the sell side and the buy side, and the capabilities in the demand-side of the market.

Paired with other reforms proposed in this paper, standardised forward products or exchange-traded hedges that work for the demand side would also support rapidly scaling up a sophisticated aggregator ecosystem. While we do not envisage aggregators to participate in such hedging arrangements on entry to market, access to appropriate risk management tools is necessary for aggregator and other demand-side business models to expand.

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[32] Billimoria, Farhad, Jacob Mays, and Rahmat Poudineh. 2025. "Hedging and Tail Risk in Electricity Markets." Energy Economics 141 (January):108132. https://doi.org/10.1016/j.eneco.2024.108132.

4. Long term investment markets

Long-term contracting remains a cornerstone of renewable energy financing, particularly through various forms of Power Purchase Agreements (PPAs). These contracts provide revenue certainty, which is essential for securing finance, but vary widely in design and complexity:

- **Pay-as-produced PPAs** are the historical mainstay for renewable energy asset finance, with buyers paying a fixed price for actual energy generated. These contracts largely insulate generators from price risk and expose them to only minimal volume risk.
- **Virtual PPAs / Contracts for Difference (CfDs)** settle financially against a reference price with no physical delivery required. They dominate corporate procurement and are the standard mechanism in many government auctions (e.g. UK, Spain). Two-sided CfDs offer symmetrical price protection and are now the default support mechanism in many EU markets.
- **Hybrid or firmed PPAs** combine renewables with storage, demand response or market purchases to provide more dispatchable output profiles—such as 24/7 renewable supply or baseload-shaped delivery.
- **Innovative structures** such as weather derivatives and volume insurance help manage resource variability. Fixed-volume swaps ('volume firming' hedges) can offer more predictable delivery profiles while maintaining renewable credentials.

Despite their advantages, long-term contracts also present a range of well understood limitations and challenges, particularly as the energy system becomes more dynamic and decentralised. Lack of liquidity and fungibility is a key issue—PPAs are typically bespoke, making them difficult to trade, exit, or use for portfolio risk diversification. Limited accessibility further compounds this problem, with small-scale and residential projects often unable to access PPA markets or negotiate favourable terms.

In addition, reduced market responsiveness can arise under fixed-price structures, which may dull incentives for generators to respond to real-time price signals—although some designs introduce partial exposure or time-based pricing to address this. The complexity of contracts is also increasing, particularly in firmed or hybrid PPAs, which require sophisticated modelling, forecasting, and integration with storage or market purchases. Finally, volume penalties and underperformance clauses can expose generators to risk even under 'pay-as-produced' arrangements, especially when output deviates significantly from expectations.

4.1 Principles

Designing effective long-term mechanisms requires balancing investment needs with market efficiency and particularly avoiding distorting dispatch or bidding behaviour. Some general principles for contract design in high renewable system include[33][34][35]:

[33] Zachmann, Georg, Lion Hirth, Conall Heussaff, Ingmar Schlecht, Jonathan Mühlenpfordt, and Anselm Eicke. 2023. "The Design of the European Electricity Market - Current Proposals and Ways Ahead," September. https://www.europarl.europa.eu/thinktank/en/document/IPOL_STU(2023)740094.

[34] Kitzing, Lena, Anne Held, Malte Gephart, Fabian Wagner, Vasilios Anatolitis, and Corinna Klessmann. 2024. Contracts-for-Difference to Support Renewable Energy Technologies: Considerations for Design and Implementation. Research Report RSC/FSR, March 2024. San Domenico di Fiesole (FI), Italy: European University Institute. https://doi.org/10.2870/379508.

[35] ACER. 2023. "ACER Policy Paper on the Further Development of the EU Electricity Forward Market." European Union: European Union Agency for the Cooperation of Energy Regulators. https://acer.europa.eu/sites/default/files/documents/Position%20Papers/Electricity_Forward_Market_PolicyPaper.pdf.

4.1.1 Revenue certainty

Long-term contracting provides the stable cashflows needed to de-risk capital-intensive assets, especially under volatile spot market conditions.

4.1.2 Balance between price stability and market integration

As with hedging, long-term contracting should avoid undermining efficient dispatch.

4.1.3 Avoid hedging disincentives

Long-term contracts should be designed to avoid crowding out natural hedging incentives, and weaken forward market signals and reduce participation. Ideally, they would coexist with shorter-term markets.

4.1.4 Appropriate risk allocation

Long-term contracts should not eliminate all risk but rather target extreme downside, or systemic volatility and poor long-term market liquidity.

4.1.5 Government role may be needed for market failures

Long-term contracting with public sector can address missing long-term markets and correct structural investment gaps.

4.1.6 Appropriate basis risk design

Choices on referencing actual performance or a benchmark-based approach affects exposure to production and price risk, which in turn shaping financing costs and behavioural incentives.

4.2 Discussion: current directions and reform

There is broad consensus that the NEM lacks sufficient long-term investment signals, with market signals alone increasingly insufficient to drive the scale and timing of needed investment—especially for firming capacity and essential system services (ESS). A persistent 'tenor gap' limits contracting beyond 3–5 years, and the uncertainty around coal exits further deters new entry. Moreover, deployment of ESS-capable technologies is hindered by regulatory inertia and market misalignment.

The early directions from the NEM review panel propose a new entry mechanism focused on services (bulk energy, shaping, firming, ESS), not technologies. This would be a hybrid of centralised and decentralised elements, include fungible, standardised contracts, and actively integrate demand-side and smaller resources. The mechanism would aim to solve the tenor gap without displacing early-stage market-based contracting.

Current proposals from the NEM review panel to address the tenor gap in the contract market may be poorly suited to demand-side options. The proposed contracting mechanism is designed to enable long-term contracting for utility-scale generation projects, whose financing models depend on reducing risks to revenue over 10–15+ years. In contrast, demand-side resources, including load flexibility, behind-the-meter storage, and distributed generation, are fundamentally different in their characteristics, value drivers, and financing needs as set out below:

- Demand-side investments are often self-hedging: they provide value by reducing exposure to high retail prices, enhancing resilience, or maximising onsite generation —

not by earning revenue in the wholesale market (for example, behind-the-meter batteries).
- Demand side resources are typically financed over shorter timeframes, often aligned with retail contracts or customer investment cycles, and are operated to meet customer preferences rather than to maximise spot market returns.
- Smaller energy providers and distributed energy resources often cannot commit to or readily access long-term contracts.

The structure of proposed long-tenor contracting mechanisms implicitly favour supply-side, utility-scale, wholesale market assets and fails to accommodate the distributed and short-horizon nature of demand-side investments. It does not relate to the realities of investing in the demand side, nor address barriers that might increase investment in this class of assets.

4.3 Recommendations

4.3.1 Consider mechanisms to support investment that go beyond addressing the tenor gap and are suitable for smaller-scale demand-side resources and aggregators.

Without explicit recognition of these differences, mechanisms designed to close the tenor gap may not enable — and may even disadvantage — new demand-side capacity. The NEM Review's early directions appear to focus on firmed renewable supply, with limited acknowledgement of the distinct nature of much demand-side investment and participation.

As with hedging instruments, any long-term investment mechanism should include options that enable independent, demand side aggregators of smaller resources to enter. Shorter duration mechanisms would better suit their capabilities, or alternative approaches entirely. Fundamentally, there is still a need for an approach to supporting investment that is similarly transparent, low-friction, and scalable (allowing aggregators to effectively manage risks), but that is also fit for purpose. Some certificate schemes mechanisms address similar issues via upfront deeming (for example, state energy efficiency schemes like the Victorian Energy Upgrades program, discussed further in section 6 below).

4.3.2 Explicitly design new investment mechanisms to allow larger flexible demand aggregators and demand-side resources to participate

As with supply-side contracting, mechanisms for supporting demand-side investment should be designed to support both natural hedging strategies, without distorting operation of the wholesale market.

There could be a natural fit with the proposed long-term investment mechanism for supporting supply side capacity that helps achieves this. Specifically, a mechanism that supports demand-side investment and participation, may lead to lead to more efficient (and liquid) short contracting with new supply side resource. This could support some new business models that aim to support flexible loads (like batteries). This in turn should allow for more competitive long-term supply side contracts. Additionally, depending on design, supporting demand-side resource could present an opportunity to manage the risk of the mechanism support vehicle otherwise being long-in supply. For other business models (for example, those based around the WDRM), this might mean ensuring mechanisms that might support peaking generation are also suitable for Demand Response Service Providers.

As demand-side resources can provide multiple value streams, including ‘non-network solutions’ within distribution networks and virtual transmission capacity, explicitly supporting value stacking can avoid regulatory workarounds and unintended consequences. The System

Integrity Protection Scheme (SIPS), used to support utility-scale batteries, provides a salutary example. While the SIPS has allowed battery projects to be supported by regulated networks and participate in competitive markets, the contracts are not well integrated, resulting in inefficient utilisation of the batteries. Designing long-term contract structures that enable efficient integration in the wholesale market, while also working efficiently with other potential value streams, should reduce the risk of perverse outcomes and increase value for investors and consumers.

5. Distribution network support services

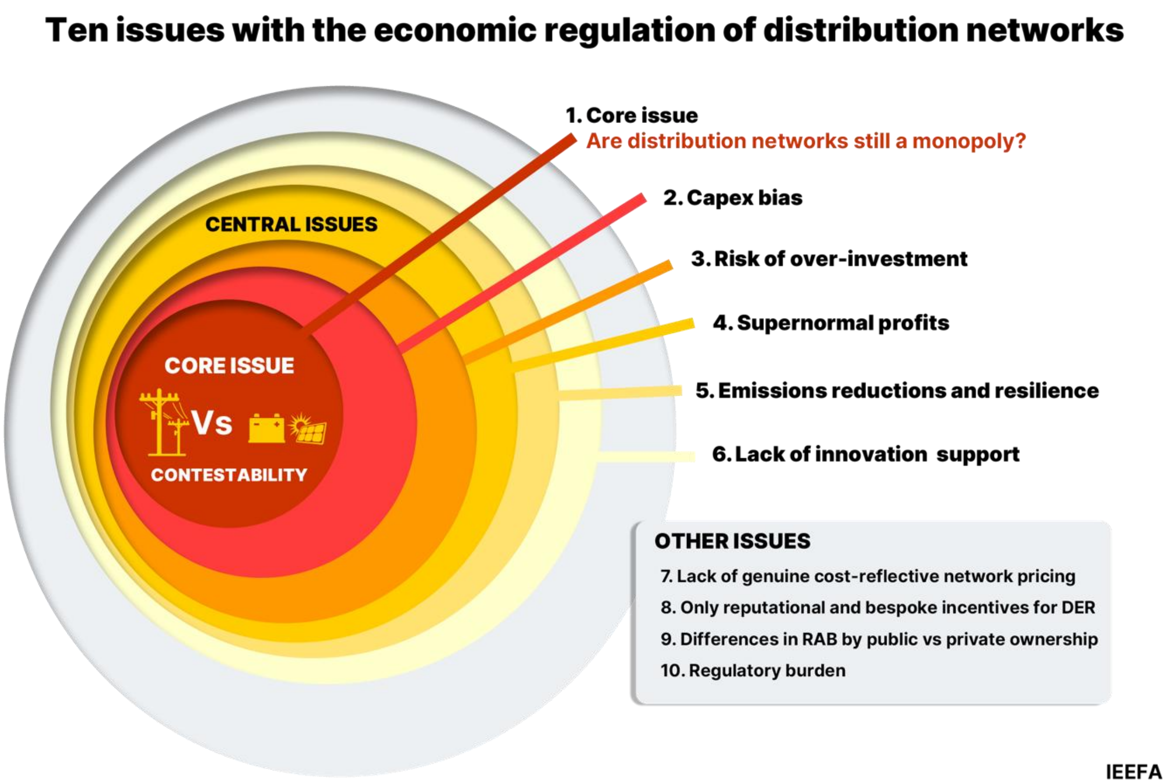
Optimising the use of demand-side resources in the NEM is not only a matter of enabling their participation in short, medium and long-term markets. There is also a large opportunity for demand-side resources to provide non-network solutions, known in Europe as flexibility services or in the NEM as network support services. To examine how aggregated DER could provide non-network solutions on a level playing field with infrastructure investment requires examining the economic regulation of distribution networks. With the right regulatory settings, DNSPs could play a major role in spurring investment in the demand side, which could be value-stacked with participation in the markets discussed in sections 2, 3 and 4.

What follows draws on analysis in Gabrielle Kuiper's 2024 report for the Institute for Energy Economics and Financial Analysis (IEEFA) Australia[36] to produce recommendations for reforming the economic regulation of distribution networks to support higher levels of network support services.

5.1 Current capital expenditure bias

The current economic regulation of Australian electricity distribution networks systematically favours traditional network infrastructure investment over demand-side solutions and aggregated DER. This regulatory bias operates through several interconnected features that collectively discourage the adoption of innovative demand-side alternatives[37].

Figure 2 From the IEEFA Australia report on Reforming the economic regulation of distribution networks



[36] Kuiper, G. (2024). Reforming the economic regulation of Australian electricity distribution networks. Institute for Energy Economics and Financial Analysis (IEEFA) Australia. https://ieefa.org/sites/default/files/2024-05/Reforming%20the%20economic%20regulation%20of%20Australian%20electricity%20distribution%20networks_May24.pdf

[37] Paper notes that many factors play into the extent to which flexible demand is available, including technology availability and commercial offers. Technology availability is tackled in the sections on deployment (state schemes) and enablers. Regardless of the regulatory environment, it is up to commercial players to design attractive offers for consumers.

Fundamental bias exists in the building block model's treatment of capital expenditure (capex) versus operational expenditure (opex). Under current regulation, capex receives preferential treatment through several mechanisms that create what economists term the Averch-Johnson effect. Firstly, capex is guaranteed recovery as long as it remains below total regulatory allowances, while opex faces reassessment every five years with no such guarantee. Secondly, capex generates ongoing returns through the weighted average cost of capital (WACC) applied to the regulatory asset base (RAB), meaning networks earn commercial returns on infrastructure investments for decades. In contrast, demand-side solutions typically require opex or contracted payments that do not attract these guaranteed returns.

KPMG identified that differences in regulatory treatment create ‘barriers to networks making efficient expenditure decisions’ noting that a 1% lower financing rate than the approved WACC could generate up to AU$150 million in annual profits for networks.[38] This structure inherently biases decision-making towards expensive capital-intensive solutions even when cheaper demand-side alternatives exist. The IEEFA analysis shows this bias has contributed to the RAB per customer increasing 60% from 2006-2015 while network utilisation fell from 57% to 39%.

Current regulation assumes distribution networks are pure monopoly service providers through the provision of poles and wires and substations (except in a small number of highly restricted cases where SAPS are permitted), failing to recognise the contestable nature of many network services that DER can now provide. The regulation has not adapted to acknowledge that ‘increasingly, distributed energy resources (DER) owned by households and businesses can provide network services, including easing congestion to avoid augmentation or replacement of network infrastructure’.[39] This regulatory blindness to contestability means there is not a level playing field between traditional infrastructure solutions and DER-based alternatives.

Elsewhere, this contestability is recognised. In Western Australia, Western Power has decided to convert more than 52% of its remote network to stand-alone power systems and microgrids. Western Power also recently ran a network support services (NSS) event via the WA’s Non Co-optimised Essential System Services process and expects to contract with several providers and is aiming to ensure that the NSS will value stack with capacity - from a load limiting perspective. Western Power will have 7 active NSS contracts for distribution feeder capacity services from aggregated DER this coming summer and in the next few months will be putting another 20 opportunities to market for summer 2026/27. This shows what’s possible under a different economic regulation. While the NEM now has rules that allow distributors to move existing customers onto SAPS, the circumstances where this is possible are highly restricted.

In Great Britain, 'flexibility services' are routinely procured from DER, with battery owners earning up to GBP33/kW/year for providing network services. By contrast, NEM regulation provides no systematic framework for such procurement.

While there have been several successful trials including Projects Networks Renewed, CONSORT, Edge, Edith and Symphony, these have not yet translated into regulatory reform that would support DER owners to be properly compensated for network services given the ten issues listed above. The current regulatory environment has resulted in missed opportunities, with Baringa modelling previously showing that proper DER orchestration could avoid AU$11 billion in network infrastructure investment by 2040.

The operation of the Demand Management Incentive Scheme (DMIS) demonstrates the marginal role assigned to demand-side solutions by DNSPs. The scheme is artificially capped at

[38] KPMG. (2018). Optimising network incentives: A report prepared for the COAG Energy Council’s Energy Market Transformation Project Team. COAG Energy Council.
[39] Op.cite 38.

just 1% of allowable revenue, signalling that demand management is viewed as peripheral rather than central to network operation. And, despite approximately $1 billion being available across the 2017-2022 network revenue period, only AU$3.2 million was actually spent on demand management by DNSPs in the NEM. The Australian Competition and Consumer Commission (ACCC) noted this reflects how 'demand management has been underutilised by distribution networks in meeting the roughly 40 hours of peak demand per year'.40. Some distribution networks (including Energy Queensland and SAPN) have since made investments in demand-side activation and flexibility within the current regulations, but such activities have not been consistent or large-scale across all DNSPs. In addition, some distribution networks have also invested in DER integration, although in most cases this has been less than 1% of revenue. The performance of distribution networks on both demand management and DER integration has varied substantially.

Table 2 lists the current performance incentives for Australian electricity distribution networks. None of these schemes currently provide strong incentives for decarbonisation, DER integration or dynamic asset management; they are not yet well aligned with the needs of a high-DER, high-renewables system. There does however continue to be smaller scale trials like the "Aggregated Demand Response Program"[41], a new demand flexibility initiative introduced by Ergon energy and Energex 2025–26 Demand Management Plan, supported by the Demand Management innovation allowance mechanism (DMIAM).

Current regulation also fails to provide adequate cost-reflective network pricing, which is essential for efficient DER integration and demand-side response. While the ACCC recommended 'mandatory assignment of cost reflective network pricing on retailers' in 2018, this has not been implemented. Without proper price signals, consumers cannot respond efficiently to network needs, and DER cannot be optimally deployed to provide network services. The AEMC found that an air conditioner installed in 2014 imposed $1,000 in network costs, but only generated $300/year in additional network payments.[42]

Table 2 Current incentive schemes under the building block regulation

Incentive Scheme	Purpose	Key Features	Current Status
Service Target Performance Incentive Scheme (STPIS)	Improve service quality and reliability	Rewards/penalises DNSPs based on reliability (SAIDI/SAIFI), customer service, and other metrics	Standardised, applies to all DNSPs
Efficiency Benefit Sharing Scheme (EBSS)	Encourage efficient operating expenditure	Shares opex underspend/overspend between DNSPs and customers over regulatory period	Standardised, applies to all DNSPs
Capital Expenditure Sharing Scheme (CESS)	Encourage efficient capital expenditure	Shares capex underspend/overspend between DNSPs and customers over regulatory period	Standardised, applies to all DNSPs

[40] Australian Competition and Consumer Commission. (2018). Restoring electricity affordability and Australia's competitive advantage: Retail electricity pricing inquiry—Final report. ACCC. https://www.accc.gov.au/system/files/Retail%20Electricity%20Pricing%20Inquiry%20-%20Final%20Report%20-%20June%202018.pdf
[41] This project aims to demonstrate the value of partnerships between networks, market systems and participants for the purpose of demand flexibility that mitigates network demand constraint.
[42] AEMC. Rule Determination: National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014. 27 November 2014. Page vi.

Demand Management Incentive Scheme (DMIS)	Encourage non-network solutions and demand management	Provides financial rewards for approved demand management projects; capped at 1% of revenue	Underutilised; very low uptake
Demand Management Innovation Allowance Mechanism (DMIAM)	Support innovation in demand management	Provides a small allowance for DNSPs to trial innovative demand management approaches	Small, project-based, limited impact
Customer Service Incentive Scheme (CSIS)	Improve customer service	Rewards/penalises DNSPs based on customer satisfaction surveys and service quality metrics	Newer, being phased in
Export Service Incentive Scheme (ESIS)	Improve DER export service quality	Bespoke, DNSPs can propose incentives for export service performance (e.g. flexible exports)	Transitional, not yet standardised

The five-year regulatory cycle and propose-respond model create additional barriers to demand-side solutions. KPMG highlighted how the current framework has been designed for a steady state, compared with the current uncertainty and dynamic rate of change. The lengthy determination process takes over three years and in 2013 was costed at approximately $330 million in administrative costs per cycle.[43] This regulatory burden favours familiar infrastructure solutions over innovative demand-side approaches that require rapid iteration and learning. The regulatory timeframe and the propose-respond approach is particularly problematic for DER integration, where technology and market conditions evolve rapidly. By the time a five-year determination is complete, the technological and market landscape may have fundamentally changed, with the approved solutions having been superseded.

The cumulative effect of these biases is that consumers pay substantially more for network services while receiving less value in terms of the current measure of network utilisation. The IEEFA analysis shows consumers are now ‘paying more than they did in 2006 for infrastructure that they use less’, with network utilisation declining 15% while costs increased 34% per customer. Addressing these regulatory biases through comprehensive reform is essential to unlock the potential of demand-side solutions and create a more efficient, cost-effective electricity system.

Further, the Draft 2025 Electricity Network Options Report, recently released by the Australian Energy Market Operator (AEMO) explicitly identifies network investment opportunities to support the forecasted growth of DER and CER, including measures to improve hosting capacity and facilitate two-way power flows.[44]

5.2 Best practice in Great Britain

Great Britain is the most advanced jurisdiction in the procurement of flexibility services, also known as non-network solutions in the United States and network support services in Australia. The Open Networks programme brought together Britain’s distribution network operators through the Energy Networks Association (ENA) and industry specialists to redefine the distribution networks’ role in transition to a net zero energy system, including a focus on

[43] Productivity Commission. Electricity Network Regulatory Frameworks. Report No. 62. 9 April 2013. Page 27.
[44] AEMO, July 2025, final 2025 Electricity Network Options Report https://aemo.com.au/consultations/current-and-closed-consultations/2025-electricity-network-options-report-consultation

expanding the role of flexibility. During the rest of 2025, Elexon (the local flexibility markets facilitator) will transform the outputs of the Open Networks program into clear and robust rules for flexibility markets. This reform built upon RIIO (Revenue = Incentives + Innovation + Outputs) revenue regulation for electricity distribution networks, introduced by Ofgem in 2013. This was followed by EU Directive 2019/943, which mandates totex regulation for distribution networks.

The shift began with RIIO-ED1 (2015–2023), which replaced separate capex and opex allowances with a unified totex model. This phase introduced a synthetic RAB, designating a proportion (say 50%) of totex as new ‘slow money’ RAB (recovered over decades via depreciation and returns) to neutralise biases toward asset-heavy investments and the old RAB. Over time, the value of the slow money RAB would increase while the value of the old RAB would decrease as assets in it are fully depreciated. A slow money rate determined by the regulator determines the share of totex that rolls into the RAB and is recoverable over multiple years. Depreciation timelines were extended to 45 years for new assets, a significant departure from the previous 20-year norm, aligning financial recovery with a more accurate lifespan of infrastructure. A fast money rate determined by the regulator determines the portion of totex that is recoverable in the year in which it is incurred. See Figure 3 below for a diagram outlining this new approach.

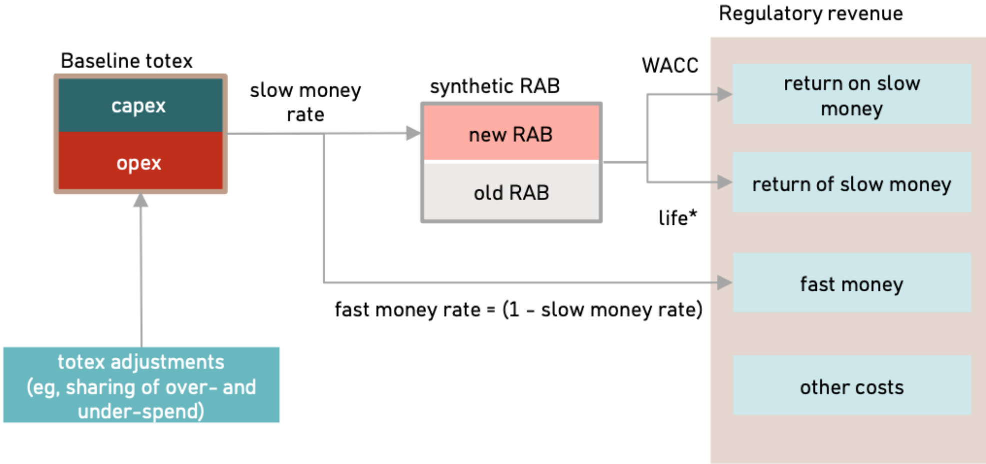
The subsequent RIIO-ED2 (2023–2028) phase has reinforced this approach by mandating a ‘flexibility-first’ strategy. Distribution Network Operators (DNOs) were explicitly instructed to prioritise cost-effective flexibility services—such as battery storage or demand response—over traditional grid reinforcement. Performance incentives were introduced to reward reductions in grid upgrade costs through demand-side management and accelerated renewable energy integration.

Software provider Electron estimates under RIIO-ED2 the six British DSOs will save £2.2 billion in total as a result of:

- an estimated £310 million due to better-informed capex decisions due to improved network visibility through flexibility markets
- £607 million through flexibility procurement instead of grid buildout, and
- a potential £1.2 billion saved due to flexibility markets enabling accelerated, smarter new connections.[45]

Figure 3: RIIO totex building block approach

[45] Electron, October 2024, How TotEx price controls shaped Britain’s energy flexibility landscape https://electron.net/how-totex-price-controls-shaped-britains-energy-flexibility-landscape/



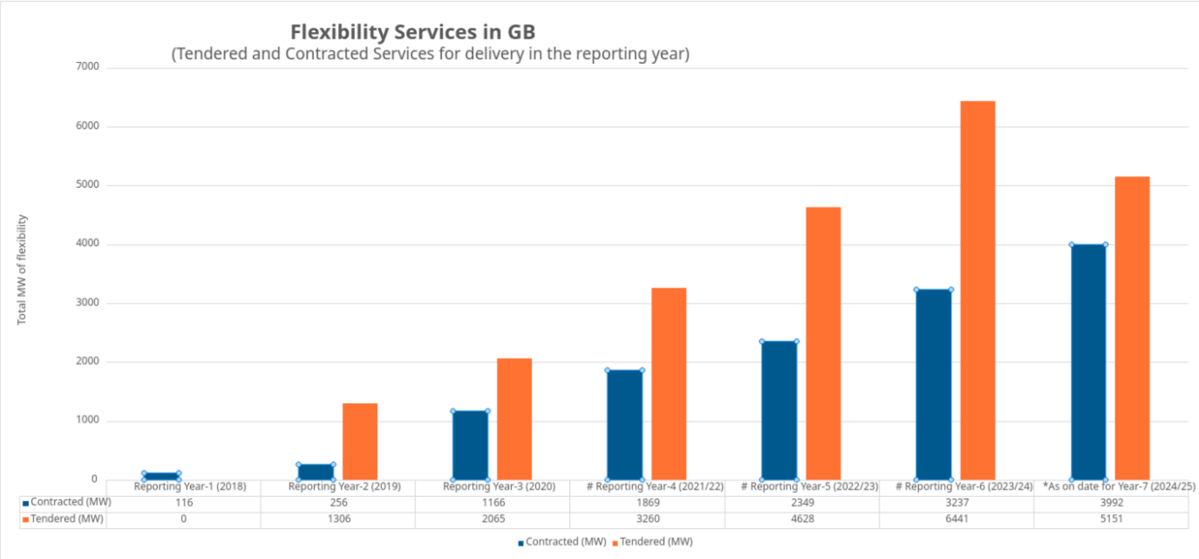
RIIO included regulatory accounting overhaul, which created synthetic regulated asset bases (RABs) to distinguish legacy assets from those funded under totex. It also implemented activity-based cost assessments to break down and analyse the costs associated with specific activities or services they provide, rather than simply tracking overall spending in broad categories like capital or operational expenditure. By assigning costs directly to individual activities—such as network maintenance, customer connections, or integrating distributed energy resources—networks and regulators can see exactly where money is being spent and how efficiently each activity is being performed. This allowed regulators to monitor outcomes and track efficiency gains such as from innovation in dynamic line ratings or virtual power plants.

Challenges in implementing RIIO included the data-intensive nature of totex requiring granular cost and performance reporting. Phased adjustments to depreciation schedules helped avoid revenue shocks from extended asset lifetimes. Early flexibility markets faced low participation due to fragmented procurement rules and small bid sizes

However, Britain contracted 4GW of distribution network flexibility from DER in 2024, of which 75% was low carbon (diesel generators can also participate), and this number is likely to grow in 2025, see Figure 4 below.[46]

Figure 4 Procurement of network flexibility services in GB from aggregated DER by year

[46] Energy Networks Association. (2024, July). New figures reveal Great Britain's world-beating energy flexibility market. Energy Networks Association Newsroom. https://www.energynetworks.org/newsroom/new-figures-reveal-great-britains-world-beating-energy-flexibility-market



Projected revenues from local flexibility markets in 2024-2025 are estimated at ~£50,000 per MW (£50 per kW) of flexibility per annum, leading to the annual revenues for various appliance types in table 3 below.[47,48]

Table 3 Revenue for DER owners for use in distribution networks

Renewable Energy Appliance	Rated Power (kW)	Flexible Power (kW)	Annual Revenue (£)	Adjustment in Behaviour
Smart appliances (e.g., smart fridge)	0.2	0.05	£2.50	Reduce demand during peak times
Electric heating	5	3.5	£175	Reduce heating load during flexibility events
EV charging	7.4	4	£200	Postpone charging to a later time
Small home battery	5	5	£250	Discharge to grid/household

£50 per kW per year applied to 4GW (4,000,000 kW) of flexibility capacity results in £200 million per year in total earnings across local flexibility, noting that actual earnings vary by location, asset type, and contractual terms and the £50/kW/year rate represents a maximum achievable value in highly constrained areas. However, flexibility procurement continues to grow, representing a large transfer of DNSP expenditure from capex to customers for access to their DER.

[47] Local Flexibility Markets: A Guide for Homeowners & Businesses - Retrofitted, accessed February 4, 2025, https://www.getretrofitted.co.uk/knowledge/local-flexibility-markets

[48] Piggott, A. (n.d.). Flexibility markets in the UK: Benefits for the grid and the public. LinkedIn. https://www.linkedin.com/pulse/flexibility-markets-uk-benefits-grid-public-anthony-piggott-tw4oe/

It is important here to note that while Great Britain has been through a series of reforms of its economic regulation of distribution networks, it is still looking at reform focused on dealing with the energy transition and that its economic regulation is likely to further evolve.[49]

5.3 Proposed reform

The economic regulation of Australia's electricity distribution networks requires urgent reform to align financial incentives with 21st-century energy system needs and Australia's climate commitments. The fact that distribution networks are providing an increasingly diverse set of service outputs and value for customers (emissions reduction, resilience, DER integration, system security, etc) and are evolving their operations to achieve things such as greater productivity, efficiency, utilisation and flexibility provides a solid rationale to review the extent to which these outputs are being effectively aligned to distributors reward and incentive structures (investment funding, incentive schemes, benchmarking) and if there are alternative models that can achieve a better alignment[50].

We propose a first-principles overhaul drawing on international models such as Great Britain's RIIO framework and US experience with non-wires solutions and performance incentives. It would require a detailed investigation and consideration of possible new models. A fresh approach could move away from performance-based regulation entirely.

Assuming, for the moment, some form of performance-based regulation, the proposed principles to reform the economic regulation of networks and changing the incentives to meet the needs of a decarbonising NEM that optimises the use of DER are set out below.

The NEM review can make an observation or recommendation that a review into reforming the economic regulation distribution networks is needed and take note of the principles outlined in this report.

Principles for reform

5.3.1 Create a level the playing field between non-network solutions/Distributed Energy Resources and network solutions

A level playing field must be created by valuing demand-side solutions equally with traditional infrastructure. Aggregators should be able to compete in delivering 'network support services' (NSS) including congestion management, voltage control and reliability services using DER and aggregated DER. This likely requires adopting totex regulation (total expenditure) to eliminate inherent capex bias in current regulation. A totex-based approach, as implemented in Britain, provides a single expenditure allowance with predetermined capitalisation rates, allowing networks to flexibly allocate resources while ensuring transparency through activity-based cost assessments and benchmarking.

Introducing totex as the basis of the economic regulation of electricity networks in Australia has been discussed ever since Professor Ross Garnaut raised concerns about 'excessive incentives for investment' in his 2011 Review for the Commonwealth Government.[51] The 2017 Finkel Review also raised concerns about capex bias.[52] The ENA-CSIRO Electricity Network

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[49] Ofgem, November 2024, ED3 Framework Consultation https://www.ofgem.gov.uk/sites/default/files/2024-11/ED3_Framework_Consultation.pdf

[50] The overall commercial value of demand flexibility will depend on value stacking, especially the extent that DER can be rewarded for providing network support services, as well as wholesale and other market services.

[51] Prof. Ross Garnaut. The Garnaut Review 2011. Page 150. 2011.

[52] Finkel, A., Moses, K., Munro, C., Effeney, T., & O'Kane, M. (2017). Independent review into the future security of the National Electricity Market: Blueprint for the future (Final report). Commonwealth of Australia. https://www.dcceew.gov.au/sites/default/files/documents/independent-review-future-nem-blueprint-for-the-future-2017.pdf

Transformation Roadmap released in 2017 recommended that a totex approach be trialled by 2018 and adopted as the default approach by 2027 was followed by further advocacy for totex by Energy Networks Australia in 2018.[53] However, the Australian Energy Market Commission (AEMC) rejected a transition to totex in 2019.[54]

Totex could enhance economic efficiency while balancing grid reliability and decarbonisation goals. Implementation challenges exist, including the need for granular data tracking and reforms to depreciation methodologies to address risks like revenue uncertainty and legacy asset management. In addition, totex needs to be considered in concert with the other changes recommended here.

Consideration will need to be given to how best to transition to a totex approach and whether additional incentives or mandates are needed to ensure Australian DNSPs put flexibility first. For example, Great Britain's RIIO-ED2 framework includes a Distribution System Operation (DSO) Incentive worth +0.4%/-0.2% of return on retained earnings annually to encourage efficient development and use of network flexibility. Hawaii's performance-based regulation includes specific DER Grid Services Utilisation metrics tracking both absolute MW of enrolled DER and percentage of forecast capability delivered. Another option would be to mandate increased procurement of network support services from DER, but this would need to be realistically calibrated against available resources and scaled up over time. The Commonwealth's battery subsidy program does however make a mandated minimum of network support services from DER more viable.

5.3.2 Introduce commercial discipline into the Regulated Asset Base (RAB)

Other infrastructure assets—such as toll roads, airports, utilities, data centres and renewable energy facilities—are valued using complex models that take into account both general market conditions and asset-specific factors, with the asset's use being a central driver of valuation changes. No such consideration applies to the valuation of the Regulated Asset Base (RAB) of distribution networks which is central to the determination of regulated revenue.

In its 2018 Retail Electricity Pricing Inquiry, the ACCC found that while RAB growth per customer has stabilised, network utilisation has not improved, and that the RABs of networks are still over-valued, as a result of historic excessive investment.[55] The ACCC considered that, 'from an electricity standpoint there are clear affordability and efficiency gains to be made from an explicit writedown made now ... a writedown should be viewed as a way of limiting the extent to which customers continue to pay for investment that has turned out to not be useful, and of improving economic efficiency.'[56]

Prior to the creation of the NEM, distribution businesses faced potential RAB optimisation by state regulators if they were found to have over-invested in capacity.[57] However, with the creation of the NEM, energy ministers decided instead to shift to the 'roll-forward' of the RAB. In 2003, Allen Consulting outlined its reasoning 'that the roll forward methodology may permit a more efficient spreading of costs over time than one where prices are reset periodically at the level that would be charged by a hypothetical (efficient) new entrant.'[58]

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[53] Frontier Economics Pty Ltd. (2018). Why Totex? Discussion paper. Energy Networks Australia. https://www.energynetworks.com.au/assets/uploads/072418_why_totex_discussion_paper_web.pdf

[54] Australian Energy Market Commission. (2019). Electricity network economic regulatory framework review 2019: Final report. https://www.aemc.gov.au/market-reviews-advice/electricity-network-economic-regulatory-framework-review-2019

[55] ACCC. Retail Electricity Pricing Inquiry—Final Report. June 2018.

[56] Ibid. Page 169.

[57] For a discussion of network asset optimisation, see: Independent Pricing and Regulatory Tribunal of New South Wales. Electricity Prices. March 1996. Page 6.

[58] This is informed by, for example, Allen Consulting Group. Methodology for updating the regulatory value of electricity transmission assets. Final report to the Australian Competition and Consumer Commission. August 2003.

In 2018 the ACCC decided against recommending the adoption of a depreciated optimised replacement cost (DORC) method on the grounds of regulatory risk, the challenge of the assessment process and the lack of certainty of reduced costs. However, the ACCC did recommend: 'The National Electricity Rules should explicitly allow for a process whereby network assets may be stranded and the costs of that stranding is shared between users and networks. The AEMC [Australian Energy Market Commission] should determine the definition of 'stranding' and how the costs of 'stranding' can be shared.'[59]

Given that no such process has been developed, that the historical over-investment has never been corrected and that the energy transition continues to create significant changes to the operation of distribution networks, some form of dynamic asset valuation is vital to ensure appropriate economic regulation of distribution network assets. Networks should face financial consequences for maintaining stranded assets, including those that could be replaced by DER alternatives. This would allow for write-downs of SWER lines in remote and regional areas and their replacement with SAPS and microgrids to provide electricity supply more reliably, with less cost and less risk as is underway in Western Power's area. Western Power is converting more than 52% of the network, which serves less than 3% of its customers in remote areas, to stand-alone power systems (SAPs) and separate or isolatable microgrids as an 'autonomous network'. As a result, Western Power is progressively decommissioning Single Wire Earth Return (SWER) lines in these regions once the SAPs and microgrids are in place.[60,61,62,63]

Because of postage stamp pricing in the NEM, there are large cross-subsidies between urban and rural areas of distribution networks. For example, the cost of electricity supply to regional Queensland through Community Service Obligation (CSO) payments to Ergon Energy Retail and Origin Energy (for customers in the Goondiwindi-Texas region) is budgeted to be $605 million for 2024-25.[64]

Within this commercial discipline, there should be scope to increase the value of RABs, for example with the electrification of transport and consumers exit from reticulated gas, as well as decrease it.[65] Another example would be increased hosting of medium and large-scale renewables in the distribution networks which would increase network productivity (see 4 below). The NEM review could perhaps undertake some case studies of how this could work in practice.

5.3.3 Assess revenue on a cycle consistent with the speed of technological change

To ensure revenue regulation remains fit-for-purpose in the rapidly evolving energy transition, it is essential to assess and reset network revenues on a cycle that aligns with the pace of technological change. Traditional regulatory cycles, such as the five-year resets under CPI-X frameworks, may lag behind DER adoption and digitalisation of networks. The ENA has already called for more flexibility within the five-year regulatory determination period in its 'The Time is Now' report.[66]

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[59] ACCC. Retail Electricity Pricing Inquiry—Final Report. June 2018. Page 172.
[60] Western Power. The future of the grid: What is it made up of?.
[61] Western Power. Future of the grid.
[62] Western Power. The future of the grid: What is it made up of?.
[63] Energy Networks Australia. WA drives smart grid solutions.
[64] Queensland Electricity Users Network. (2025, May 2). Submission to the Queensland Competition Authority on the Draft 2025–26 Ergon regulated retail electricity prices for regional Queensland [Submission]. Queensland Competition Authority. https://www.qca.org.au/wp-content/uploads/2024/12/13-qeun20444801.pdf
[65] Energy Networks Australia, August 2024, The Time is Now – Getting smarter with the grid https://www.energynetworks.com.au/assets/uploads/The-Time-is-Now-Report-ENA-LEK-August-2024.pdf
[66] Ibid

Moving to a more regular cadence of revenue assessment—likely every two years, or even more frequently—would enable distribution network service providers (DNSPs) and the AER/regulators to respond more dynamically to shifts in technology, consumer behaviour and market conditions. This may require changing the current propose-respond approach. A faster and more regular assessment would not only support innovation and risk-sharing between networks and consumers, but could ensure that financial incentives remain consistent with consumer expectations and the broader transition to net zero emissions. A side benefit of more frequent revenue assessments is enhanced consumer engagement: more frequent reviews create opportunities for ongoing relationships with consumers and stakeholders which can help build trust, foster transparency, and ensure that regulatory frameworks remain responsive to the needs of both consumers and the energy system as a whole.

Changing the incentives

5.3.4 Incentivise network productivity, for both imports and exports

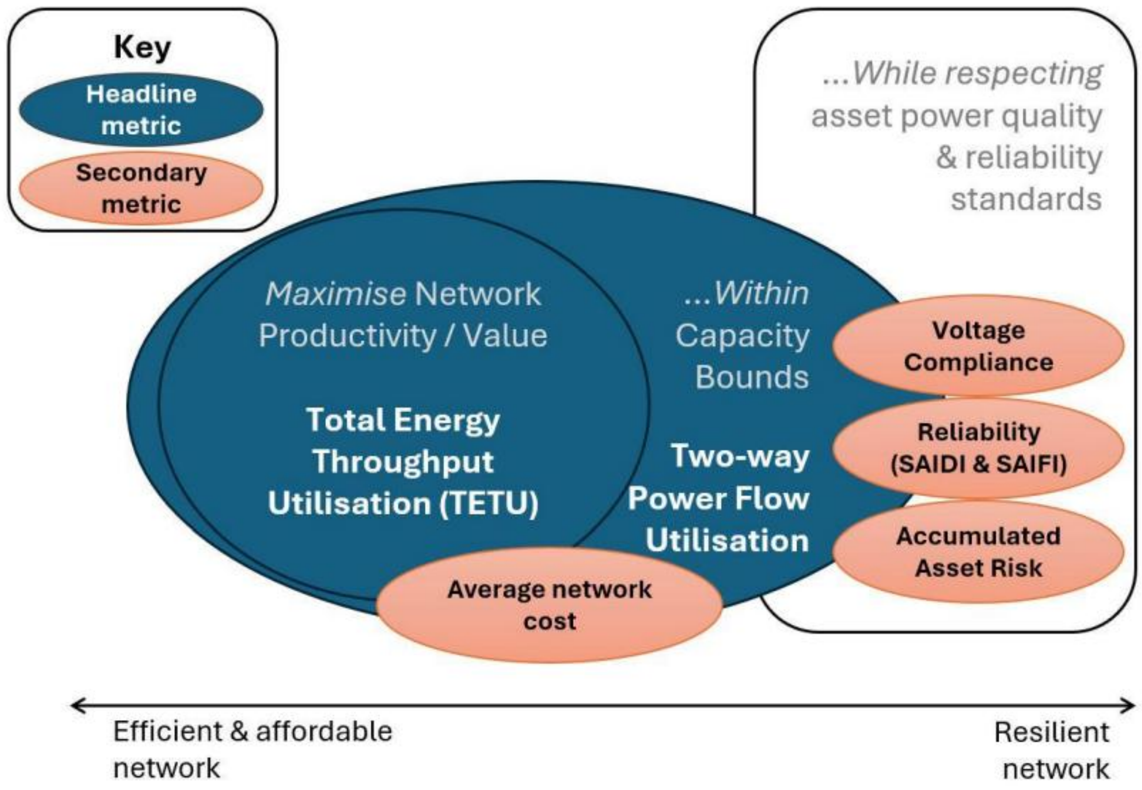
The traditional metrics of network utilisation which examine the approximately 40 peak hours of energy demand per year and aggregate at the whole distribution network level are less useful in a multi-way distribution network and shed no light on where and how to obtain more value from the network for the remaining 99.4% of the time. Researchers at the Institute for Sustainable Futures at UTS have proposed two alternative headline metrics to traditional network utilisation:

- *Total Energy Throughput Utilisation (TETU)* focussed on maximising the customer value that is facilitated by a grid connection, in the form of energy imported from the grid, exported to the grid and self-consumed.
- *Two-way Power Flow Utilisation* focussed on understanding and balancing the level of capacity risk accrued to deliver the network productivity represented in the TETU. This provides visibility of the critical time-of-day and seasonal variations in two-way grid usage that inform how TETU can be maximised.[67]

These headline metrics are complemented by three secondary asset-level metrics for voltage compliance, reliability (System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI)), and accumulated asset risk—the first two of these are discussed below.

[67] Langham, E, Ibrahim, I., Rispler, J and Roche, D. (2024). Reimagining Network Utilisation in the Era of Consumer Energy Resources. Prepared by UTS with the support of Energy Consumers Australia. Version 1.1, Nov 2024.

Figure 5 Revenue for DER owners for use in distribution networks



Relationship between proposed headline and secondary utilisation metrics

UTS also proposes a simple inflation-adjusted average per unit and per customer network cost to summarise customer value derived from the network.

The UTS report is clear that these metrics were not designed to be used for regulatory incentives, however they provide a valuable starting point for considering how networks should be rewarded in the era of multi-way flows.

The TETU calculates the portion of the network's capacity that is utilised by the energy flows, either forward or reverse, accounting for locally consumed CER energy using the following mathematical equation:

$$Total\ Energy\ Throughput\ Utilisation\ (\%)^{\S} = \frac{Forward\ Energy\ Flow + |Reverse\ Energy\ Flow| + Locally\ Consumed\ CER\ Energy^{\wedge}}{Seasonal\ Rated\ Capacity \times Time\ Frame^{*}}$$

where,

$$^{\wedge}Locally\ Consumed\ CER\ Energy = Expected\ CER\ generation^{\#} - Estimated\ curtailment^{\#} - |Reverse\ Flow\ Energy|$$

* Time frame can be several hours, day, month, season, or the whole year in hourly basis.
\# Curtailment can be quantified as the difference between the amount a customer's CER is allowed to export and the theoretical potential output of the installed CER if no network constraint was present.[9]
§ This metric can be calculated at a range of different network asset levels (e.g. feeder), but the default undertaken in this report is the Zone Substation. If self-consumption is to be excluded, an alternative formula is provided in Section 4.1.2.1.

While UTS suggests the 'default' scale of application would be at the zone substation level, then averaged across the network across a year to a single percentage figure, ideally this would be done at the feeder or street substation/transformer.

Testing with real world data found the TETU metric behaved as desired in response to increased solar with battery storage 'solar soak' load shifting, and other desirable customer actions that reduce curtailment increasing in value with solar input.

UTS summarises the advantages, disadvantages, and potential applications of the TETU metric as listed in Table 4.

Table 4: Pros, cons and applications of the proposed TETU energy metric

Pros	Cons	Applications
Reflects all useful customer exchanges from the grid (import, export, local consumption of CER) relative the 'full potential' of the asset. **• Can reflect seasonal rated capacity differences (summer/winter).** **• Voltage-tripping leading to lost solar exports is captured.** **• Yields single value per asset, which is simple for reporting and benchmarking.**	Voltage-tripping leading to lost self- consumption is not captured (as this is just seen as a resulting rise in grid imports) • Does not tell us anything about risk or timing of low/high utilisation events so has more value for planning (e.g., optimising assets, tariff design, incentives scheme) than for operational purposes. • CER exports and self-consumption are not currently considered 'outputs' in the AER's capital and operating expenditure benchmarking, which may represent a barrier to incorporating utilisation into network performance reporting.	• Annual, system-wide figure is useful for regulation (alongside power metrics). • Seasonal, asset-specific, or spatially mapped versions could be useful for planning. • Preserving calculation components could increase forward/reverse flow energy to be used in other applications.

A Total Energy Throughput Utilisation Scheme (TETUS) would support recognising performance in imports, exports and self-consumption. The exact nature of this scheme is beyond the scope of this report, given its focus on principles, but development of possible forms of this incentive for discussion is recommended. Similarly, the use of the TETU in economic regulation does requires new or more granular data, or *access* to data from existing smart meters and/or other devices, which is an important implementation consideration.

Such a scheme could implicitly account for new or expanded distribution network responsibilities under the 'Distribution System Operator' (DSO) title. There would also be incentives as to how these DSO functions relate to consumers under the customer service incentive (see section 5.3.6 below).

5.3.5 Incentivise voltage management

The Service Target Performance Incentive Scheme (STPIS) focuses on traditional reliability metrics—System Average Interruption Duration Index (SAIDI) System Average Interruption Frequency Index (SAIFI) —and customer service, but export services represent a critical new dimension of network performance that requires dedicated measurement and incentivisation. The Australian Energy Regulator (AER) has introduced the Export Service Incentive Scheme (ESIS) which allows distribution networks to propose bespoke incentives for export service performance. However, the AER stated, 'We expect that the ESIS will be a transitional measure until it is possible to introduce a standardised scheme for all DNSPs via the STPIS'.

The current, optional and bespoke Export Service Incentive Scheme (ESIS) is insufficient given the existing and growing level of exports and so the STPIS needs updated metrics. UTS's view is that 'SAIDI and SAIFI are adequate reliability metrics, but we recommend that they add the most value in contextualising utilisation if reported at the zone substation level and are viewed alongside asset-level power and energy metrics'. This is from a metric perspective but if we are rewarding network productivity through a TETU-based scheme, the STPIS is unlikely to be needed.

However, voltage compliance is a major power quality challenge in the NEM and requires urgent attention.[68] While UTS note that there is an inherent incentive to manage voltage causing solar curtailment within the TETU metric, this fails to account for over-voltages both resulting in procurement of excessive electricity supply and the damage of higher than necessary voltage on consumer appliances. The Victorian Essential Services Commission requires networks to report on:

- Number/percentage of assets above the maximum voltage limit.
- Number/percentage of assets below the minimum voltage limit.

While these metrics are a useful starting point, it is recommended that more sophisticated voltage metrics are developed which take into account the duration of over-voltages, for example. More sophisticated measures including network typology-based metrics or customer density adjustments could also be considered depending on data availability and state estimation analysis.

Consumers pay additional costs as a result of over-voltages, but there is currently no financial incentive for distribution networks to improve voltage performance so an additional incentive scheme is necessary. However, financial rewards should not be provided for compliance against the nominal voltage standard. Data can be obtained from solar inverters with unbalanced power flow/state estimation analysis used as needed.

The Victorian and Queensland networks have begun to reduce average voltages and Endeavour is also working on voltage management, but this issue needs to be prioritised across the NEM.

In addition, it may become necessary to incentivise the management of thermal limits.

5.3.6 Increase the proportion of revenue at risk for customer service

The Customer Service Incentive Scheme (CSIS) was introduced by the Australian Energy Regulator in 2020 to motivate electricity distributors to improve customer service. Under the CSIS, distributors engage with customers to identify which services need enhancement, set targets based on these preferences, and are then financially rewarded or penalised depending on their performance against these targets. The scheme covers areas such as communication during outages, call centre responsiveness, and complaints management, with the aim of aligning service delivery with what customers value most.

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[68] University of Wollongong. (2025). Consumer benefits of improved voltage management project report. Australian Energy Regulator.

If the STPIS was to be abolished, it is recommended that the CSIS be expanded to include DER-related customer services, including connection times, flexible exports and support for flexible demand (e.g. moving hot water services into solar generation periods). This refined incentive scheme should consider customer preferences and support involving consumers in DNSP decision making process. There are opportunities to learn from and enhance the Better Resets process in this regard.

5.3.7 Incentivise DNSPs to contribute to accelerating decarbonisation

In 2023, an emissions reduction objective was incorporated into the National Electricity Objective (NEO) of the National Electricity Law (NEL): 'the achievement of targets set by a participating jurisdiction – for reducing Australia's greenhouse gas emissions; or that are likely to contribute to reducing Australia's greenhouse gas emissions.'[69] However, there have been no changes to the economic regulation of electricity networks as a result.[70,71]

DNSPs can and should contribute to achieving the decarbonisation objective of the NEO and should be rewarded for their role in reducing emissions via a decarbonisation reward scheme which uses the value of emissions reduction (currently the interim value is $66 per tonne CO_2-e). Emissions reductions from DNSPs' energy advisory function in supporting customers to move from reticulated or bottled gas to electricity and DNSPs' efforts in facilitating EV charging should be estimated, based on guidelines developed for this purpose. DNSPs would be allocated a reasonable proportion of these emissions reductions and the scheme would multiply this by the current value of emissions reduction.

There is a risk of double counting here as electrification should increase distribution network utilisation. However, this incentive could be tailored to designed to reward efficient and smart electrification.

5.3.8 Incentivise DNSPs to become more resilient in a changing climate

A 2025 rule determination from the AEMC requires distribution networks to explicitly consider climate and resilience risks in their planning and investments and includes:

- new resilience expenditure factors that DNSPs and the AER must have regard to when proposing and assessing capital and operating expenditure for resilience
- formal Network Resilience Guidelines (guidelines) which the AER must develop, publish and maintain in accordance with a set of requirements.
- new distribution annual planning and reporting requirements for resilience.

The Value of Network Resilience (VNR) is a new metric introduced by the AER to guide investments that make networks more robust against extreme weather, by quantifying the economic value customers place on avoiding long, disruptive outages, with initial values set at $1,440/kWh for residential and $14,400/kWh for business customers.

This rule change may be sufficient to incentivise resilience, but should be monitored and reviewed and updated as necessary. Inherently this rule should encourage the use of aggregated DER, especially in the form of SAPS and microgrids to reduce bushfire risk, but that will also depend on whether or not totex and enhanced commercial discipline of the RAB are introduced.

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[69] Government of South Australia. National Electricity (South Australia) Act 1996.
[70] AEMC. How the national energy objectives shape our decisions, Final guidelines. 28 March 2024.
[71] AER. AER - Guidance on amended National Energy Objectives - Final guidance note. September 2023.

5.4 Proposed implementation of outcome-based revenue determinations that value the demand-side

For DNSPs to effectively deliver against all the other principles, distribution networks have to change their internal cultures. Economic regulation should support cultural change management – people, processes and technology to show that the use of DER for network support services is viable and valuable. DNSPs are becoming more sophisticated Distribution System Operators and that needs to be reflected in the rules.

What follows is a straw person of how the STIPS, EBSS, CESS, DMIS, DMIAM and ESIS could be replaced with the new and amended incentive schemes in table 5 below. If necessary, a temporary scheme could incentivise the use of DER and aggregated DER to provide network support solutions, until such provision becomes standardised. What is proposed here is intended to stimulate discussion. Any new incentive schemes or regulatory changes should be based on demonstrated need and effectiveness.

Table 5: Proposed new and amended incentive schemes

Incentive Scheme	Purpose	Key Features	Revisions/ Additions
Total Energy Throughput Utilisation scheme (TETUS)	Measure of network productivity	Performance against Total Energy Throughput Utilisation (TETU)	New – reflects use of network for exports, imports and self-consumption
Voltage compliance penalties	Improve service quality and reliability	Rewards/penalises DNSPs based on voltage	New – reflects slow pace of change away from excessively high voltages
Decarbonisation Incentive scheme (DIS)	Supports DNSPs important role in assisting electrification	Support for electrification – both customers disconnected from the gas network and facilitation of EV charging connections in line with planning	New – using the value of emissions reduction
Customer Service Incentive Scheme (CSIS)	Improve customer service	Rewards/penalises DNSPs based on customer satisfaction surveys and service quality metrics	Review and expand to include DER-related customer services, incl. connection times, flexible exports and support for flexible demand
If required:			
Flexibility incentive scheme (FIS, temporary)	Reward use of DER for network support services	Based on MW of flexible DER enrolled to provide network support services	New temporary incentive with transition away from capex bias

Over time an increasing proportion of DNSP revenue would be tied to measurable performance metrics in these incentive schemes. The Government may like to consider allocating funding to a specific network innovation fund, administered by ARENA to assist with this transition, as has been done in Britain. Another consideration in the implementation is increased standardisation, discussed below with regard to the DER technical standards regulator.

The reform could roll out through three stages:

- Phase 1 (2025–2026): Develop changes needed to measure proposed metrics (including testing and refining TETU) and totex rules and complete necessary rule changes.
- Phase 2 (2027–2030): Staged implementation of totex, dynamic asset valuation and new incentive schemes and conversion to bi-annual revenue determinations.
- Phase 3 (2031–2035): Gradually decrease revenue at risk from the RAB and increase revenue at risk from incentive schemes.

6. Deployment mechanisms

Increasing the participation of demand-side in the energy market will require the deployment of a range of both responsive and passive technologies, including:

- Thermal efficiency upgrades
- Metering and sub-metering infrastructure
- Energy management systems
- Efficient electric appliances and equipment with ‘smart’ connectivity/open communication protocols
- Battery storage systems and vehicle-to-home and -grid (V2H and V2G) technologies.

In some cases, the upfront cost of these technologies creates a barrier to investment, with extended payback periods making them a high-risk investment for energy users, as with supply-side infrastructure. Other barriers to deployment include information asymmetries and split incentives.

To overcome these barriers, governments at all levels have created incentive programs to accelerate technology deployment. This section examines how these programs are functioning, identifies issues with the current suite of programs, and proposes reforms focussed on deploying technologies that deliver more value to the energy system.

6.1 State white certificate schemes

Energy savings obligation schemes (also known as ‘white certificate schemes’ when certificates are part of scheme design) are market-based programs designed to drive investment in energy efficiency by requiring energy retailers (or other obligated parties) to achieve and verify energy savings. These schemes set annual targets for obligated parties (usually retailers) to achieve. In turn, obligated parties purchase certificates representing verified energy savings from third parties, which in some jurisdictions can be traded. Four jurisdictions (New South Wales, South Australia, Victoria and the ACT) operate schemes of this type detailed in Appendix A.

6.2 Federal Government programs

Household Energy Upgrades Fund (HEUF)

The Household Energy Upgrades Fund (HEUF) was established to offer $1 billion for discounted green loans, enabling households to access finance for solar, batteries, and energy efficiency upgrades at below-market interest rates. Currently, four banks—Bank Australia, ING, Plenti, and Westpac—offer discounted green loans under the scheme. While the HEUF aims to help more than 110,000 households, there are no public statistics available on the number of loans written to date, or the upgrades financed, making it difficult to assess the success of the program.

However, international evidence suggests that HEUF is unlikely to be supporting large-scale household electrification upgrades. For example, the European Banking Authority (EBA) 2023 comprehensive review of green loans and mortgages across 45 institutions in Europe found that green loan volumes remain a very small share of total household lending.[72]

[72] European Banking Authority EBA Report In response to the call for advice from the European Commission on Green Loans and Mortgages Dec 2023

Small-scale Renewable Energy Scheme (SRES)

The SRES supports the uptake of distributed renewable energy systems, primarily rooftop solar, as well as heat pump and solar hot water systems by households and small businesses. As with the state white certificate schemes, the installation of eligible technologies creates tradable Small-scale Technology Certificates (STCs) each representing a megawatt-hour of expected renewable energy generation. Installers use the value of certificates to provide discounts to consumers on the upfront cost of appliances and equipment.

As the scheme operates nationally, it covers states without white certificate schemes (Queensland, Western Australia, the Northern Territory, and Tasmania). States with schemes usually permit the 'stacking' of SRES incentives with their own incentives. For example, a household can obtain a discount on the upfront cost of a heat pump hot water system from STCs generated under the SRES as well as VEECs generated under the VEU.

As with most of the state white certificate schemes, appliances installed under the scheme are not obligated to have open communications or contribute to positive energy system outcomes. Similarly, no attempt is made to measure the time at which the energy is generated/saved from equipment installed under the scheme.

The SRES is currently scheduled to end in 2030.

Cheaper Home Batteries Program

On 1 July 2025, the 'Cheaper Home Batteries Program' (CHBP) commenced through SRES. Each eligible battery system generates STCs based on its usable capacity, capped at 50 kWh per system. Instead of passing STC costs onto energy retailers (as is typical under the SRES), the government directly purchases and retires the STCs created for batteries at a cost of $40 per STC (which will decline over time). As with the SRES in general, both households and businesses can be awarded STCs under the program. There are no requirements on the way that batteries installed under the scheme are used but in NSW under the PDRS and in WA under its subsidy scheme, the incentive is only 'stackable' if battery owners sign up to a VPP.

6.3 Summary of issues

This section summarises issues with the current suite of incentive programs using an *energy system lens*. In general, these programs are delivering positive outcomes for energy users, especially lower bills. However, the current incentive programs are delivering sub-optimal outcomes for the energy system, and possibly perpetuating the view of energy system planners that demand-side resources are problems to be managed rather than valuable solutions in a 21st century grid.

Schemes continue to rely on deemed methods to estimate their impact, limiting their relevance to energy system planning and forecasting

Existing incentive schemes are based largely on an outdated 1990s approach to energy efficiency, relying mostly on ex-ante deemed energy and emission savings—precalculated estimates of reductions—rather than measuring actual performance, with monitoring and verification. This approach has drawn criticism for overstating savings. For example, the ESS's deemed methods for commercial heat pumps assumes uniform usage patterns, ignoring real-world operating hours. There are also questions about additionality. For example, only 52-62% of the EEI Scheme's reported savings were additional.

There are also non-deemed methods in each state scheme, but uptake has been low for a number of reasons including administrative frictions (regulators taking too long to assess and approve projects) and a lack of financial guarantee for end users, who need to provide capital for the upgrades despite revenue uncertainty until monitoring and verification is complete.

Internationally, there are examples of incentive schemes – such as in California – that use modern methods of monitoring and verifying the impact of demand-side actions, including thermal efficiency improvements.[73] These methods use smart meter data combined with other data in regression analyses at an aggregate scale, allowing energy system planners to forecast with great accuracy the potential impacts of the program on energy demand – to the hour.

Time-of-use or time-of-savings / generation not generally considered, leading to contradictory deployment

All state subsidy schemes treat all kilowatt-hours equally, regardless of timing. For example, the NSW ESS uses a static conversion factor (1.06× for electricity savings taking into account network losses).[74] While the NSW PDRS was intent on addressing peak demand, it is still based on deemed savings, applies only to batteries currently and does not take into account time of day.

As a result, savings can take place in the middle of the day when increased demand is desirable to use abundant solar generation, and might be helpful to manage minimum operational demand. Similarly, there is no incentive to reduce winter heating loads during evening gas-dependent peaks.

Federally, the SRES currently only covers solar, batteries (via the CHBP) and water heaters, but does not include any flexibility requirements to receive the subsidy. The HEUF is experimenting with loan products that offer preferential rates for battery customers who participate in VPPs, but the impact of this policy is yet to be seen.

In summary, the schemes are mainly designed to deploy demand-side technologies without consideration of how and when they are used, ignoring the growing value of demand flexibility in a high penetration renewable energy system.

We need both flexible demand technology deployment as well as aggregation and dispatch. The proposed bulk supply market changes and reforms to the economic regulation of distribution networks creates the opportunity for the latter, leaving flexible demand technology deployment under-supported. Out-of-market subsidy schemes are the appropriate vehicle for flexible demand technology deployment, given that has been their historic role.

Thermal performance measures that support flexible demand are absent from all schemes

Space conditioning and refrigeration-based load flexibility, in particular, pre-cooling buildings, is an emerging area of significant potential demand flexibility. For this to be possible high-thermal performing buildings (both commercial and residential) are needed. A previous challenge of thermal improvements has been a lack of ability to measure impact. This is now solved with modern metering techniques allowing for accurate predictions of impacts. Currently only the VEU is beginning to re-introduce insulation as a thermal performance measure and there is a lot more that could be explored in terms of thermal performance measures to support space conditioning and refrigeration based load flexibility.

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[73] For example, Pacific Gas and Electric in California is making use of open source methods known as the 'CalTRACK Methods' to forecast the impact of demand-side actions. See CalTRACK Methods, https://docs.caltrack.org/en/latest/methods.html.

[74] New South Wales Department of Climate Change, Energy, the Environment and Water. (2025, March). Energy Savings Scheme: Rule and Regulation Change 2025. https://www.energy.nsw.gov.au/sites/default/files/2025-02/DCCEEW_Energy_Savings_Scheme_Consultation_Mar_2025.pdf

6.4 Proposed reform

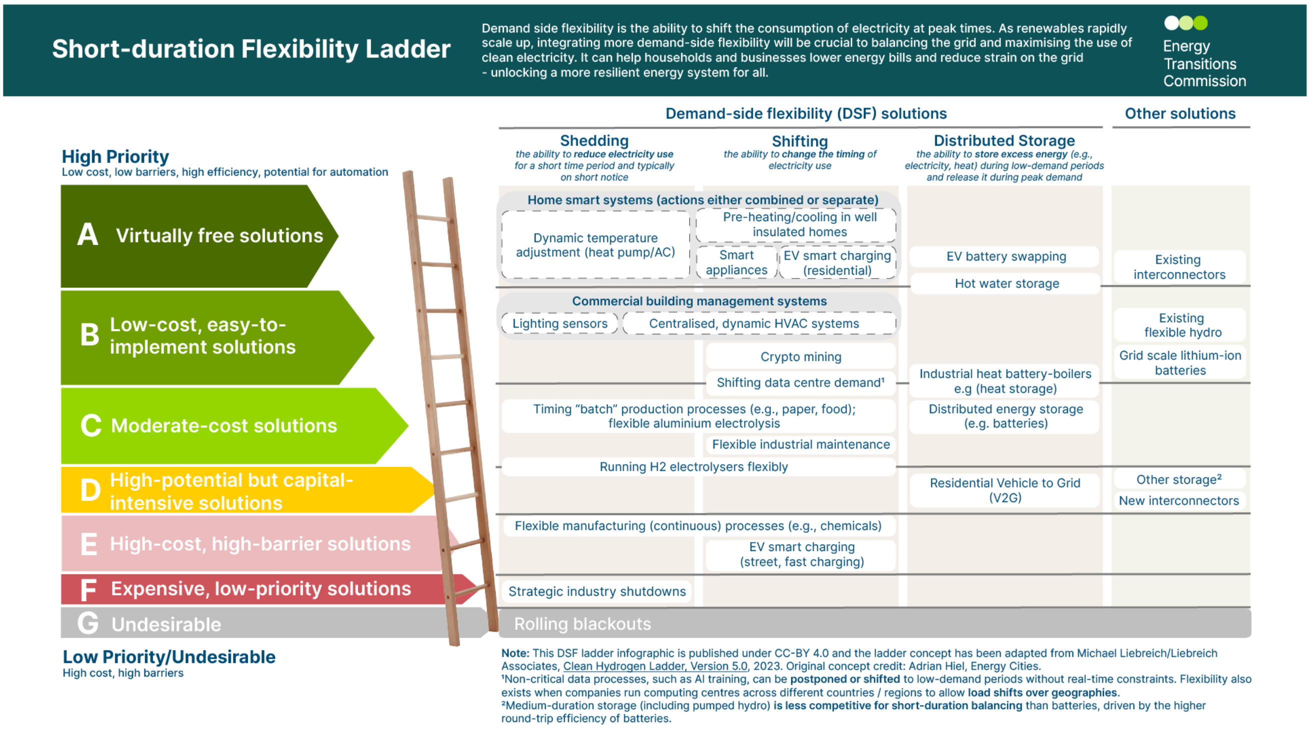
With the transformation of the NEM to 82% emissions reductions by 2030 and proposed changes to the wholesale, derivatives and long-term markets/contracting, the best use of out-of-market subsidy schemes would be to re-orient them to accelerate and embed flexibility into household and business electrification. There are capital cost barriers that could be overcome, preferably through a national scheme/approach.

The aim should be to subsidise the up-front cost of efficient and flexible appliances and equipment, with rewards for the flexible use of those machines determined in the markets or contracts themselves, be that for bulk supply or network support services as outlined in the earlier sections of this paper.

The Energy Transitions Commission's Short-duration Flexibility Ladder (see Figure 6) provides a means of prioritising solutions for subsidies, starting with 'virtually free solutions' of heat pump/split system air conditioning (AC), some thermal performance upgrades (well insulated homes), smart appliances and hot water upgrades then moving on to low-cost, easy-to-implement solutions such as commercial building management systems and industrial heat pumps. Vehicle-to-Home (V2H) and Vehicle-to-Grid (V2G) is likely to move up the ladder to be in this category in Australia within a couple of years as well.

Solar Victoria provides a model for how a state administered subsidy scheme has supported electrification with quality appliances, audits for compliance and enforcement measures and the provision of information for consumes.

Figure 6: Short-duration Flexibility Ladder



The principles for the reform of subsidy programs are set out below:

6.4.1 Support the purchase of efficient and flexible appliances and machines, especially where the up-front cost is a barrier to electrification

Many households, especially those on lower incomes or living in rental properties, struggle to afford the initial capital investment required to replace gas appliances with efficient electric alternatives even though these upgrades can deliver substantial long-term savings on energy bills. For example, the retail cost of a 170-litre electric heat pump for residential water heating can range from $1,888 to $5,340, while a comparable gas appliance may cost between $1,245 and $1,950, making electrification unaffordable for many despite its future benefits.[75]

As the Energy Efficiency Council has noted previously in relation to the NSW ESS, 'Encouraging fuel switching from fossil fuels to electricity should therefore become a primary objective of the ESS as it will support NSW to achieve its legislated target to achieve net zero emissions, by reducing sources of emissions from the Stationary Energy (excluding Electricity) sector.'[76]

Converting white certificate schemes to rebate schemes for electric appliances with inbuilt flexibility would speed up electrification and make large quantities of flexible demand available. At a minimum this could include the following residential flexible demand:

- hot water systems (including solar and heat pump) with in-built flexibility (see below on GEMS)
- flexible split system (heat pump) air conditioning (e.g. with wifi see below on GEMS)
- high efficiency pool pumps with in-built flexibility, and
- thermal performance (e.g. insulation and glazing) improvements.

And the following commercial and industrial flexible demand:

- heat pump hot water with in-built flexibility
- industrial heat pumps
- energy management information systems (EMIS)
- efficiency and flexibility improvements or line upgrades at industrial sites (e.g. chemical plants, manufacturing plants, mills)
- efficient and flexible refrigeration and cooling systems (thermal storage) at retail and commercial sites
- replacement or modification of HVAC systems so that they can be used flexibly, and
- changes in the way energy is used in schools or hospitals that enable flexibility.

6.4.2 Incorporate modern measurement and verification approaches into scheme design

All subsidy schemes would benefit from better measurement and verification (M&V) of their impacts through ex-ante and ex-poste evaluations using metered data. Ideally, modern M&V methods using metered data (combined with other data, such as weather information) would be used to calculate scheme impacts instead of deeming, particularly to verify the time at which energy impacts (whether reductions or shifts in demand) take place.

Doing so would increase their value to energy planners and value for money, for both energy consumers (when scheme costs are recovered through bills) and taxpayers (when the costs are borne by government). As noted above, there are good examples of programs in overseas jurisdictions (particularly US states) that use modern M&V methods to estimate aggregated impacts of demand-side interventions.

6.4.3 Accompany schemes with consumer information and advice

Information and advice for households and businesses are useful to support the uptake and use flexible demand. Solar Victoria provides a solid model for consumer information, see, for

[75] Senate Economics References Committee Residential Electrification Report March 2025, Chapter 3 – Consumer barriers and support
[76] EEC Submission to the Energy Savings Scheme and Peak Demand Reduction Scheme statutory reviews 2025

example: https://www.solar.vic.gov.au/solar-hub In addition, under the National Consumer Energy Resources (CER) Roadmap, taskforce project C.3.1 is a 'Communication framework and strategy to ensure CER participation is compelling and easily understood by all consumers'. This could be designed to support and enhance the rebate programs.

6.4.4 Subsidy schemes should be complementary to market participation

Subsidies for up-front costs should be linked to standards (especially technical standards for monitoring and verification) and suitability to participate in the markets discussed earlier in this report.

The NSW Government has made steps in this direction with recent changes to its battery subsidies. Since the introduction of the Federal Cheaper Home Batteries Program, NSW paused the BESS 1 method in the PRDS (a subsidy for reducing the cost of installing home batteries). The BESS 2 method (which provides a subsidy if a home battery owner enrols in a VPP) was retained and expanded, effectively making state incentives for batteries contingent on participation in a VPP..

6.5.5 Ideally, such a scheme would be national

Ideally a rebate scheme would be national to cover all consumers. A national scheme would be far more administratively efficient for OEMs, industry and governments, and hence consumers. One option could be to leverage the SRES, expanding it to deliver a wider range of technologies.

Another option would be to establish new schemes where they don't exist, in Queensland, Tasmania and Western Australia, creating a network of state programs that cover energy use across Australia. The advantage of this approach would be to leverage state governments' strengths in service delivery and program implementation, given their relationships and communication channels with households and businesses through existing white certificate schemes and other subsidies and programs supporting electrification and emissions reduction.

This could be aligned with a national registry of approved appliances and equipment, maintained by the Commonwealth, that would streamline processes for product manufacturers and installers alike, and improve quality for consumers as an expansion of GEMS.

6.5.6 Consider sub-targets or increased rebates for vulnerable cohorts to improve equity

The EEC has consistently advocated for measures to ensure that the benefits of energy efficiency programs are more accessible to those facing the greatest barriers, such as low-income, elderly, or medically vulnerable groups.

The experience of the Victorian Home Heating and Cooling Upgrades program highlights the need for stronger equity mechanisms. While the program was designed to support up to 250,000 low-income Victorian households, only 28,905 installations were completed—an uptake rate barely exceeding 10% of the target.[77] This shortfall underscores persistent barriers such as upfront costs, lack of awareness, and complex eligibility requirements, which disproportionately impact vulnerable cohorts. Without targeted incentives, many of the most disadvantaged households remain excluded from the benefits of energy efficiency and electrification.

[77] Solar Victoria Solar Homes Program Reporting https://www.solar.vic.gov.au/solar-homes-program-reporting

Whether through sub-targets or increased rebates for activities delivered to households experiencing financial hardship, those in social or community housing, and other priority groups need additional assistance in any revised scheme.

7. Technical enablers of aggregated DER

A number of technical and regulatory changes are required to remove barriers to aggregated DER participation in future markets. It is important that the NEM review consider these matters because until they are addressed, aggregated DER market participation cannot be optimised.

1. Legislate a DER Technical regulator

It is essential that legislation establishes a DER Technical Regulator with a clear mandate to develop, implement, and enforce robust technical standards for all forms of DER—including rooftop solar, battery storage, electric vehicles, and flexible demand technologies—across the National Electricity Market. [78]Central to this reform is the integration of the Greenhouse and Energy Minimum Standards (GEMS) regime and its regulator into the Clean Energy Regulator, creating a single, accountable authority for both energy efficiency and technical performance standards for DER devices and systems. This move would end years of policy inertia and ensure that standards like demand response capabilities, interoperability, and voltage management are not only modernised but also consistently applied and enforced nationally.[79] Work begun on behind-the-meter interoperability standard but it has yet to be agreed and regulated nationally. Behind-the-meter interoperability is currently a major barrier to demand-side participation.

Such a regulator would also be responsible for aligning DER technical standards with international best practice, ensuring consumer protections and supporting the rapid scaling of flexible demand and storage. The consolidation of GEMS under the Clean Energy Regulator would further streamline compliance, improve data flows, and enable dynamic, future-proofed standards that reflect the evolving needs of a high-renewables, consumer-driven energy system. In addition, such a regulator could support standardisation across DNSP practices, for example, for dynamic operating envelopes.[80]

2. GEMS to require flexibility capability in major household appliance standards

IEEFA analysis demonstrates that by mandating smart, dynamically managed appliances—capable of responding to price or grid signals—Australia can shift significant energy use to periods of abundant renewable generation, reducing wholesale electricity costs and emissions, while delivering substantial savings to consumers. [81] For example, dynamically managed hot water systems could save consumers up to $6.7 billion annually by 2040 and provide up to 22 GW of flexible demand, equivalent to two-thirds of peak demand according to UTS analysis.[82] Similarly, most new RCACs already feature Wi-Fi or demand response capabilities, and requiring all units to be 'smart' would future-proof the appliance fleet and support grid stability, especially as electrification accelerates.[83] Urgent reforms should be undertaken to embed minimum flexibility capability requirements—such as open communication protocols, interoperability, and consumer override—across all major appliances, including hot water,

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[78]Engineers Australia. January 2025. Accelerating Energy Transition Series, The revolution will be in distribution: Faster, cheaper decarbonisation through integrating Distributed Energy Resources (DER)

[79] The Energy. May 2025 Feds take regulation of DER back to square one

[80] Kuiper, G. (2024, December). *How rapid implementation of flexible exports could maximise rooftop solar* (Briefing Note). Institute for Energy Economics and Financial Analysis. https://ieefa.org/resources/how-rapid-implementation-flexible-exports-could-maximise-rooftop-solar

[81]IEEFA. August 2024. The Big Shift: How smart hot water can lighten the load for consumers and grid

[82] Roche, D., Dwyer, S., Rispler, J., Chatterjee, A., Fane, S. & White, S. (2023). Domestic Hot Water and Flexibility. Report prepared for ARENA by UTS Institute for Sustainable Futures

[83]IEEFA. October 2024. Smart air conditioners could reduce energy bills for consumers.

reverse cycle (split system) air conditioning, and potentially pool pumps. These are requirements the devices can be used flexibility, not that they will be used flexibly.

3. **Create open data and open communication protocols, use open-source software, make detailed network data available and allow aggregator (third party access) to real-time smart meter data with consumers' permission**

Open data and open communications are crucial enablers for efficient DER market participation. Robust protocols must support real-time or near real-time data exchange, enable automated responses to market and grid signals, uphold stringent cybersecurity measures, and ensure seamless interoperability among diverse vendors and technologies.

Public access to granular network data empowers aggregators and service providers to pinpoint the most advantageous sites for DER deployment and to better understand network constraints that may influence service delivery. When this is paired with consumer-authorised access to smart meter data, it unlocks advanced optimisation of DER portfolios and enhances the accuracy of forecasting flexible demand and supply.

Internationally, open Application Programming Interfaces (APIs) and standardised data formats have proven effective in fostering innovative business models and boosting market efficiency. California's Rule 21, for instance, mandates specific communication protocols and data accessibility standards for DER, setting a benchmark for interoperability and transparency. In Australia, the adoption of CSIP-AUS—the Common Smart Inverter Profile based on IEEE 2030.5—marks significant progress in enabling secure, standardised communications between DER and distribution networks. Victoria's recent requirements have effectively established CSIP-AUS as a de facto standard, with widespread adoption across inverter manufacturers.

Despite these advancements, substantial work remains to establish truly open data and information flows within the National Electricity Market (NEM), both on the supply and demand side. Monitoring and verification processes must be accurate, timely, unbiased, and standardised to ensure the integrity of DER integration and market participation.

Energy Consumers Australia (ECA) has proposed a rule change aimed at modernising and improving the distribution system planning process and network data.[84] It includes a requirement on DNPSs to develop and publish a roadmap for collecting and utilising more granular data. Ideally the NEM review would explicitly recognise these gaps and recommend solutions to accelerate the development of open, secure, and interoperable data sharing across the sector.

4. **Upgrade Market Systems**

The operational integration of distributed energy resources (DER) in Australia's electricity markets is fundamentally constrained by outdated, manual processes for registration, portfolio management and market participation. As Mitch O'Neill highlights, the current reliance on inefficient, paper-based systems for tasks such as updating DER portfolios or registering additional capacity in contingency Frequency Control Ancillary Services (FCAS) is not only cumbersome, but also creates significant barriers to entry for market participants.[85] These manual processes are ill-suited to the scale and dynamism required for effective DER orchestration and risk overwhelming the market operator as DER uptake accelerates.

[84] Energy Consumers Australia. January 2025. Integrated Distribution System Planning (electricity) rule change request https://www.aemc.gov.au/sites/default/files/2025-02/New%20rule%20change%20proposal%20-%20Energy%20Consumers%20Australia%20-%2020250122.pdf
[85] O'Neill, M. (2023, September 7). Integrating price-responsive resource into the NEM consultation [Submission]. grids.dev.

To address these challenges, the market operator must deliver digital, low-cost interfaces that streamline registration and portfolio updates, as well as modern platforms for bidding, dispatch, and operational data exchange. Transitioning to digital processes will reduce administrative burdens, lower costs, and enable more participants to engage in flexible demand and ancillary services markets.

Beyond registration, comprehensive modernisation of market systems is essential to enable real-time DER participation. This includes:

- **Enhanced Forecasting**: Advanced forecasting tools are needed to predict DER availability and flexibility across multiple timeframes, incorporating real-time weather data, historical trends, and consumer behaviour patterns to improve operational planning and market efficiency.
- **Automated Real-Time Dispatch**: Systems must be capable of coordinating and controlling thousands of distributed assets in real time, ensuring system security and compliance with network constraints while maximising the value of DER.
- **Automated Settlement**: As the number of DER transactions grows, automated settlement processes are critical to manage the complexity of small-scale transactions and ensure timely, accurate payments to DER providers.
- **Interoperability and Data Exchange:** Seamless communication between market systems and distribution network management is vital for maintaining power quality and operational safety. Standardised protocols for data exchange and device interoperability are required to support this integration.

Achieving this transformation will demand significant investment in both software and hardware infrastructure, underpinned by robust, standardised digital protocols. The shift to modern, digital market systems is a prerequisite for unlocking the full value of DER, ensuring efficient market participation, and supporting Australia's transition to a high-renewables energy future.

Appendix A: State white certificate schemes

New South Wales (NSW) Energy Savings Scheme (ESS) and Peak Demand Reduction Scheme (PDRS)

The NSW Energy Savings Scheme (ESS) was established in 2009 evolving from the earlier Greenhouse Gas Reduction Scheme (GGAS, 2003–2009), which included a component for demand-side energy savings. It requires electricity retailers and large users to meet annual energy savings targets through the creation and surrender of Energy Savings Certificates (ESCs), each representing 1 MWh of electricity saved, and is administered by the NSW Independent Pricing and Regulatory Tribunal (IPART).

The ESS covers a range of energy efficiency upgrades, including:

- commercial and residential lighting upgrades (historically the dominant activity)[86]
- efficiency improvements or line upgrades at industrial sites (e.g. chemical plants, manufacturing plants, mills)
- behavioural changes in the way energy is used in schools or hospitals
- installation of efficient refrigeration and cooling systems at retail and commercial sites
- replacement of out of date equipment, or modification and efficiency improvements to existing equipment
- compressed air systems (that are oversized or leak)
- variable speed drives (VSDs) fitted to inefficient motor
- modifications to large refrigeration systems
- replacement or modification of HVAC systems
- decommissioning or retiring of old plant made redundant by more specialised equipment
- installation of high efficiency motors
- installation of power factor correction capacitors
- replacing electric or gas water heaters
- installing or replacing existing air conditioners
- replacing windows or doors with thermally efficient windows or doors
- installing or replacing existing pool pumps
- installing efficient showerheads
- draft proofing or sealing windows, doors, chimneys and exhaust fans
- replacing refrigerated cabinets (small businesses only)
- installing or replacing certain motors (small businesses only).[87]

Activities that involve switching to another fuel may be used to create energy savings certificates (ESCs) provided the activity meets certain requirements.

The ESS has undergone multiple rule changes to close loopholes, improve measurement and verification and expand eligible activities. It remains the largest white certificate scheme in Australia by volume, but has been criticised for its heavy reliance on lighting upgrades, especially in the commercial sector (which accounted for up to 85% of certificates at times).[88]

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[86] E.g. Around 69% of the certificates created in 2021 were due to energy savings from lighting activities in the commercial, small business and residential sectors. IPART. July 2022. NSW Energy Savings Scheme Compliance and Operation in 2021 Report to the Minister. https://www.energysustainabilityschemes.nsw.gov.au/ess-pdrs/documents/report/report-minister-nsw-energy-savings-scheme-compliance-and-operation-2021

[87] See the IPART website https://www.energysustainabilityschemes.nsw.gov.au/Home/About-ESS/Overview-of-the-ESS/Eligible-activities-and-equipment

[88] NSW Department of Climate Change, Energy, the Environment and Water. (2024). Annual Report 2023–24, Volume 1.

The NSW Peak Demand Reduction Scheme (PDRS) was established in September 2021and provides incentives for activities that:

- reduce the use of electricity (during peak times) – ie the current ESS,
- store and shift electricity use from peak times ie install new behind the meter battery energy storage systems (between 2-28kWh capacity)
- Virtual Power Plant (VPP) participation - signing a household battery up to VPP for 3 years.

The NSW PDRS is designed to reduce peak demand by 1,029MW (7.5% on 2019 peak) by 2030, and is projected to result in $388m of total benefits and $154m in net benefits by 2030.[89]

Victoria: Victorian Energy Upgrades (VEU), formerly VEET

The Victorian Energy Efficiency Target (VEET) was also established in 2009 and renamed the Victorian Energy Upgrades (VEU) program in 2015. Activities generate Victorian Energy Efficiency Certificates (VEECs), each representing one tonne of CO_2-e abated. Accredited persons create and trade these certificates to meet retailer obligations.

The various installation and project-based activities that create VEECs under the VEU program are listed in the table in Appendix B.

Similar to the ESS, the VEU covers a wide array of technologies, including:

- Lighting (residential and commercial)
- Heating, ventilation, and air conditioning (HVAC)
- Hot water systems (including solar and heat pump)
- Refrigeration and freezer upgrades
- Building shell improvements, and
- Industrial and commercial process upgrades.

The VEU is currently undergoing a strategic review.[90]

Victoria also offers complementary rebates through Solar Victoria for solar PV and hot water, with specific programs for rental properties, community housing and apartment buildings. Importantly there is an income ceiling for these rebates. For the hot water rebate, the household taxable income of all owners combined must be less than $210,000 per year. From 1 July 2025, an additional $400 rebate will be available for Australian manufactured hot water systems.

The ongoing refinement of eligibility criteria, consumer protections, stakeholder engagement and reporting by Solar Victoria demonstrates good practice in designing public programs that accelerate the uptake of efficient, flexible appliances and machines, while directly addressing up-front cost barriers.[91]

South Australia: Retailer Energy Productivity Scheme (REPS), formerly REES

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https://www.nsw.gov.au/sites/default/files/2024-11/dcceew-annual-report-2023-24-volume1-240302.pdf

[89] UTS Institute for Sustainable Futures. ARENA Knowledge Sharing Demand Flexibility Portfolio Retrospective Analysis Report. July 2023. Report prepared for ARENA. By Briggs, C; Hasan, K; Dwyer, S; Bashir, U; Niklas, S; Alexander, D; and Chatterjee, A.

[90] Victorian Government, Department of Energy, Environment and Climate Action. (2025). Strategic Review of the Victorian Energy Upgrades program. https://engage.vic.gov.au/victorian-energy-upgrades-program-strategic-review

[91] https://www.solar.vic.gov.au/solar-homes-program-reporting

The South Australian scheme was established as the Residential Energy Efficiency Scheme, REES in 2009; reformed as the Retailer Energy Productivity Scheme (REPS) in 2021. REES was initially focused on delivering energy efficiency upgrades to low-income and vulnerable households, but REPS broadened its objectives to include demand management and productivity improvements.[92]

The REPS Activity List and official scheme documentation confirm that the following technologies and activities are eligible:

- Lighting upgrades (including LEDs)
- Efficient appliances (fridges, freezers, washing machines, dryers)
- Hot water systems (including heat pumps and solar)
- Building shell improvements (such as insulation and draught proofing)
- Showerhead replacements.

In addition, connection of demand responsive HVAC, heat pump hot water system, pool pump or EV charger which complies with 'AS/NZS 4755 or is otherwise approved by the Minister or their delegate' are recognised under the REPS.[93]

The REPS includes a priority group sub-target (recently increased to 25%) and transition multipliers for activities delivered to vulnerable households, ensuring a minimum proportion of scheme benefits reach those most at risk of energy hardship.

ACT: The Energy Efficiency Improvement Scheme (EEIS)

The Energy Efficiency Improvement Scheme (EEIS) is the ACT's retailer obligation scheme introduced in 2013. The scheme has supported a range of activities comparable to the other schemes, including:

- Appliance upgrades,
- Building shell improvements (e.g., insulation),
- Lighting upgrades,
- Hot water system upgrades and
- Showerhead replacements.

Frontier Economics was commissioned to independently review the EEIS for the period 2019–2023. The review recommended:

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[92] Government of South Australia, Department for Energy and Mining. (2024). Retailer Energy Productivity Scheme (REPS): Activity List and Guidelines. https://www.energymining.sa.gov.au/__data/assets/pdf_file/0019/455856/REPS-Guideline-2024.pdf

[93] Demand response capability requirements for installation of all air conditioning types (excluding evaporative, portable and close control air conditioners), up to a cooling capacity of 19kW inclusive have applied since 1 July 2023 under a Technical Regulator Guideline: 'Air conditioners within the scope of this guideline shall comply with any of the following standards:

- AS/NZS 4755.3.1:2014; or
- AS/NZS 4755.2 (when published); or
- the equivalent of the superseded AS/NZS 4755.3.1.2012 (for a limited period until 1 July 2025 or 12 months after the publication of AS/NZS 4755.2, whichever is the later date).

These air conditioners are also required to comply with three [demand response modes] DRMs - DRM1, DRM2, DRM3. The Technical Regulator may add other standards in future revisions of this guideline.' Draft DR AS 4755.3.1:2024 Part 3.1: Interaction of demand response enabling devices and electrical products—Operational instructions and connections for air conditioners (this Standard) was published on 12-08-2024. The draft standard is not publicly available and as is proprietary.

- Updating eligible activities to avoid overlap with other government programs and respond to technology and market changes (e.g., consider removing mature activities like lighting).
- Improve the scheme's additionality by refining activity eligibility and savings factors.
- Increase engagement from smaller (Tier 2) retailers to enhance competition and innovation.
- Consider expanding the scheme to cover gas retailers
- Consider harmonising the EEIS with the NSW Energy Savings Scheme to reduce compliance costs for multi-jurisdictional retailers.
- Explore alternative cost-recovery mechanisms and targeted support outside the scheme for vulnerable groups.[94]

[94] Frontier Economics. (2024). Review of the Energy Efficiency Improvement Scheme: Final Report. ACT Government, Environment, Planning and Sustainable Development Directorate. https://www.climatechoices.act.gov.au/__data/assets/pdf_file/0018/2518002/eeis-review-2024.pdf

Appendix B: VEU activities by type

Category	Part #	Activity	Eligible for residential	Eligible for non-residential
Water heating	1	Installing electric boosted solar or heat pump water heater and decommissioning an electric resistance water heater	Yes	Yes
	3	Installing electric boosted solar or heat pump water heater and decommissioning a gas or LPG water heater	Yes	Yes
	44	Installing an air source heat pump water heater for commercial (including multi-residential) and industrial applications	No	Yes
Space heating and cooling *	6	Installing a high efficiency air conditioner	Yes	Yes
	28	Upgrade of gas heating ductwork	Yes	Yes
Space conditioning	12	Underfloor insulation*	Yes	Yes
	13	Window replacement	Yes	Yes
	14	Window retrofit	Yes	Yes
	15	Weather sealing	Yes	No
Shower rose	17	Installing a water efficient shower rose and decommissioning a water inefficient shower rose	Yes	Yes
Refrigerators and freezer	22	Purchase of high efficiency refrigerators or freezers	Yes	Yes
Television	24	Purchase of high efficiency televisions	Yes	Yes
Clothes dryer	25	Purchase of energy efficient clothes dryers	Yes	Yes
Pool pump	26	Installing high efficiency pool pumps	Yes	Yes
Public lighting upgrade	27	Upgrade of public lighting	Yes	Yes

Category	Part #	Activity	Eligible for residential	Eligible for non-residential
In-home display unit	30	Installing in-home display units	Yes	No
High efficiency motor	31	Installing high efficiency motors	No	Yes
Refrigerated cabinets*	32	Installing high efficiency refrigerated display cabinet	No	Yes
Refrigeration fan motor	33	Installing high efficiency refrigeration fan motor	No	Yes
Building based lighting upgrade	34	Undertaking a lighting upgrade in certain buildings, structures or areas	No	Yes
Non building based lighting upgrade	35	Undertaking a lighting upgrade in an area not attached to a building or structure	No	Yes
Pre-rinse spray valve	36	Installing efficient pre-rinse spray valves	No	Yes
Gas-fired steam boiler	37	Installing an energy efficient gas-fired steam boiler replacing an inefficient gas-fired steam boiler	No	Yes
Gas-fired water boilers or heater	38	Installing an energy efficient gas-fired water boiler or heater replacing an inefficient gas-fired water boiler or heater	No	Yes
Electronic gas/air ratio control	39	Installing a gas/air ratio control system into a boiler	No	Yes
Combustion trim system	40	Installing a combustion trim system into a boiler	No	Yes
Gas-fired burner	41	Installing energy efficient gas-fired burners into a boiler	No	Yes
Economizer	42	Installing an economizer into a boiler	No	Yes
Cold room	43	Upgrading or installing refrigeration systems for cold rooms	No	Yes

Category	Part #	Activity	Eligible for residential	Eligible for non-residential
Home energy rating assessment	45	Undertaking a home energy rating assessment	Yes	No
Induction cooktop	46	Sale of an induction cooktop	Yes	No
Project based activities	-	Measurement and verification activities for custom projects	No	Yes
	-	Benchmarking activities for custom projects	No	Yes

Appendix C: Australia electricity market requirements for aggregated DER participation

Wholesale market – from 2027	Power			Duration (minimum)	Response time
	Raise	Lower	Hold		
Voluntary scheduling from 5 November 2026	1MW (aggregated or singular)	1MW (aggregated or singular)	No	5 minutes	
Contingency FCAS	Power			Duration (minimum)	Response time
	Raise	Lower	N/A		
Very fast raise service, very fast lower services, fast raise service, fast lower service, slow raise service, slow lower service, delayed raise service and delayed lower service collectively.	1MW (aggregated or singular)	1MW (aggregated or singular)	No	FCAS facilities may cease to provide Contingency FCAS once frequency recovery has occurred.	very fast (two-second), fast (six-second), slow (60-second) or delayed (five-minute)
Wholesale DRM	Power			Duration	Response time
A demand response service provider (DRSP) can bid demand response directly into the wholesale market as a substitute for generation		1MW (aggregated or singular)	No	5 minutes	Generally, 5 minute dispatch – but options to use ramp rates, fast start inflexibility profile (FSIP) bidding and other bidding strategies, as determined by the DRSP
Reliability and Emergency Reserve Trader (RERT)	Power			Duration	Response time

	Raise	Lower	Hold		
The Reliability and Emergency Reserve Trader (RERT) is a function conferred on AEMO to maintain power system reliability and system security during peak demand events using reserve contracts	10MW (can be aggregated)	10MW (can be aggregated)	No	30 minutes (minimum)	short notice (between three hours and seven days) and medium notice (between ten weeks and seven days) and long notice (more than 10 weeks) Note that length of dispatch and activation times can vary by contract

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Institute for Energy Economics and Financial Analysis

Reforming the economic regulation of Australian electricity distribution networks

Ten reasons to change how we pay distribution networks in a high DER world

Dr Gabrielle Kuiper – IEEFA Guest Contributor

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Key Findings

The economic regulation of electricity distribution networks has a significant impact on electricity bills for households and businesses, and more broadly on Australia's economic productivity, but the current system has failed to deliver efficient costs for distribution network services.

The current system is based on the assumption that distribution networks are the monopoly providers of network services. However, increasingly, distributed energy resources (DER) owned by households and businesses can provide network services, including easing congestion to avoid augmentation or replacement of network infrastructure.

Internationally, momentum is growing towards reform of the economic regulation of electricity networks, with overseas jurisdictions introducing contestability and payments for DER to provide network services, totex regulation and performance incentives for decarbonisation.

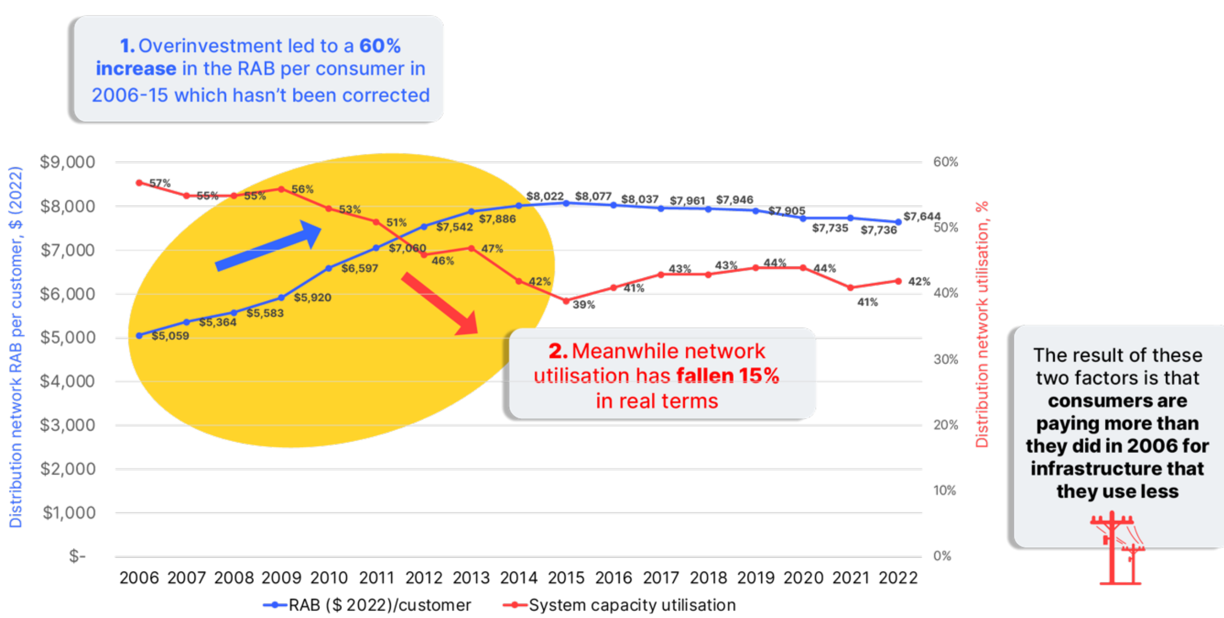
IEEFA recommends the Productivity Commission undertake a first-principles review of the economic regulation of distribution networks, which would identify ways to ensure efficient costs of network services in a high-DER world.

Executive Summary

The cost of building, replacing and maintaining the poles, wires and substations of the electricity distribution networks impacts all households and businesses that pay electricity bills. Collectively the value of the regulatory asset base (RAB) of all distribution businesses in the National Electricity Market (NEM) is now AU$82.7 billion, and distribution network charges typically account for 25%-35% of electricity bills.[1] The way distribution networks are remunerated – their economic regulation – therefore has consequences for Australia's economic productivity.

The per-customer value of the RAB was AU$5,059 in 2006. It rose dramatically by 60% to a peak of AU$8,077 in 2015, before falling 5% to AU$7,644 in 2022. The surge in the value of the RAB per customer coincided with a slump in distribution network utilisation, from 57% in 2006 to 39% in 2015. This has subsequently levelled out at around 41% but has never recovered to 2006 levels. While the trends since 2015 may be interpreted as positive stabilisation, **over 2006-2022, the per-customer RAB rose 34%, while network utilisation fell 15% in absolute terms**. Consumers are now paying much more for a service they are using less than in 2006, with no correction to the RAB value.

Distribution network RAB per customer vs utilisation 2006-2022



Source: IEEFA. All figures in real $2022.

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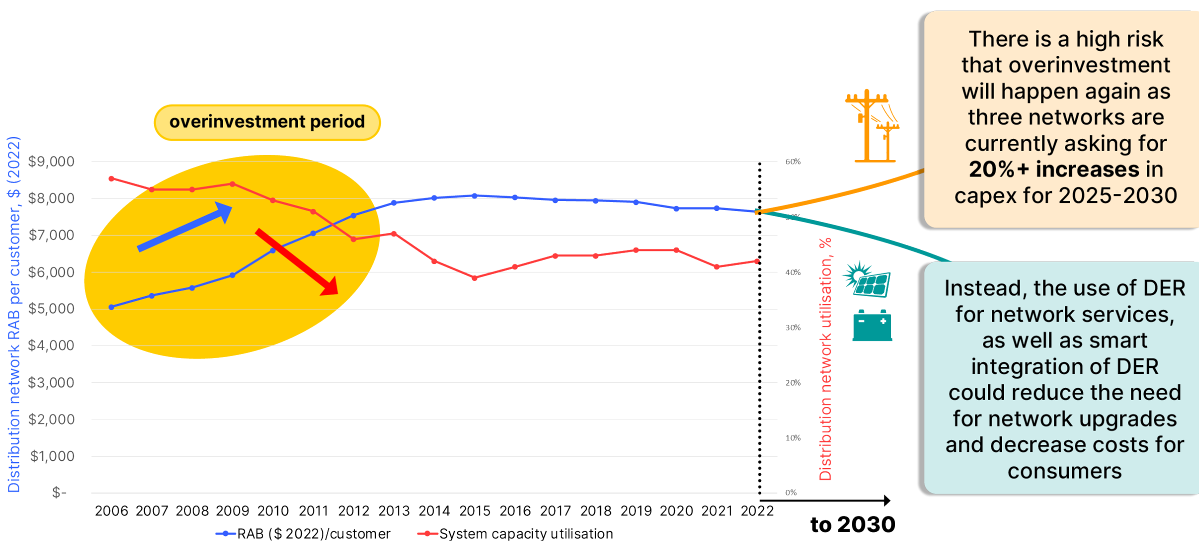
[1] Australian Energy Regulator (AER). State of the energy market 2023. 5 October 2023. Note: distribution costs have been proportionally lower due to high wholesale costs over the last couple of years but have been as high as 40% in the past.

This analysis suggests that while the earlier RAB over-investment ceased due to reforms in 2012-2013, **the economic regulation has not delivered efficient costs for distribution network services.**

Moreover, **there is an emerging, concerning risk of future over-investment** comparable to that seen around 2006-2015, with distribution networks requesting higher capital allowances, which will result in increases in both the value of the RAB and electricity bills. Three distribution network service providers (DNSPs) submitted 2025-2030 revenue proposals to the Australian Energy Regulator (AER) in January 2024, all of which have over 45% of households with rooftop solar, and a growing number with batteries in their regions. All three (SA Power Networks, Ergon and Energex) are proposing 20-22% increases in capital expenditure (capex), compared with the 2020-2025 regulatory period. Most of these increases seem to be for replacement of aging assets or for augmentation. It is unclear why the increases are so large when network utilisation is so low, and rooftop solar and battery uptake is increasing.

There is an urgent need to review economic regulation of distribution networks to avoid overinvestment and support decarbonisation

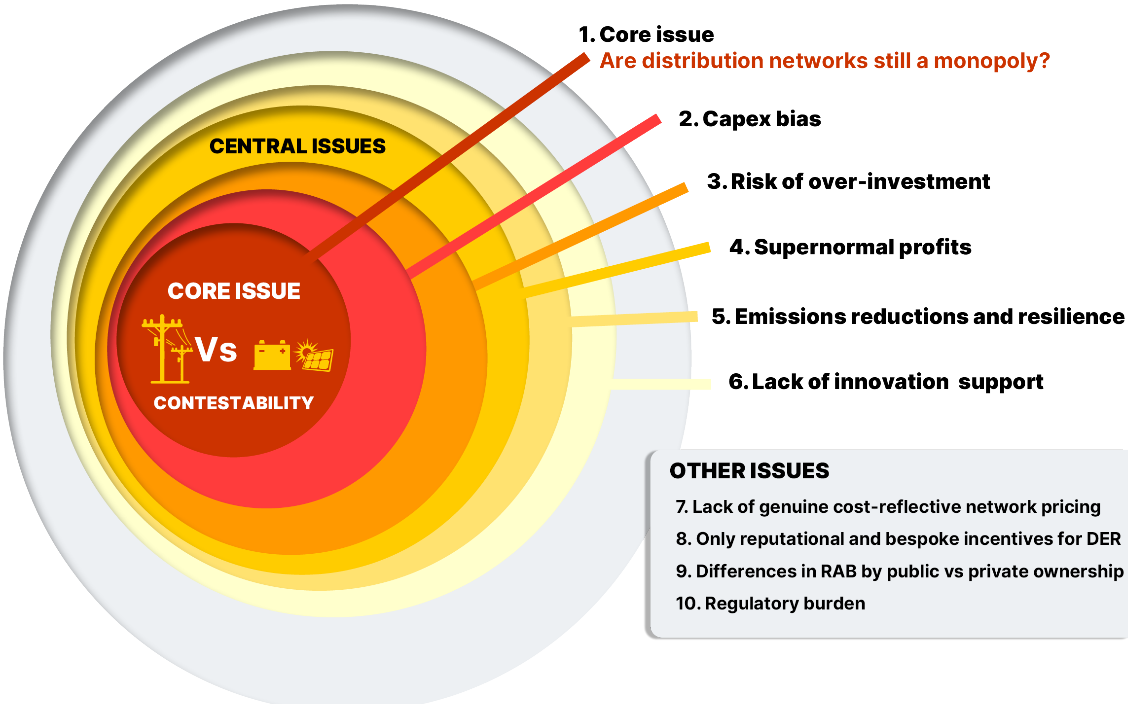


Source: IEEFA based on AER data.

This report argues that, alongside the over-investment risk, a large opportunity exists to cut network costs by reforming the economic regulation of distribution networks, especially to enable distributed energy resources (DER) like solar batteries and smart appliances to provide network services. **Network services that DER can provide commonly include congestion management, voltage control, reliability enhancement and network deferral.** If DER can substitute for costly augmentation or replacement infrastructure – poles and wires and substation capex investment – this should reduce bills. Based on now conservative figures for DER uptake, Baringa has estimated that AU$10 billion in distribution network investment could be avoided by 2040 through efficient DER integration, including the use of DER to provide some network services.

The economic regulation of distribution networks effectively dates from 1980s Great Britain, with a few tweaks. This report sets out ten reasons to reform distribution network revenue regulation, to help Australia meet its 82% renewables by 2030 target at an efficient cost.

Ten issues with the economic regulation of distribution networks



IEEFA

In terms of regulatory economics theory and for the purposes of this report, the core issue is whether distribution networks are still a monopoly service or whether they are contestable. This report details examples of two use cases in which DER can compete with networks. The first is through the substitution of remote and regional networks with standalone power systems and microgrids. In south-west Western Australia, Western Power has decided to convert more than 52% of its remote and regional network serving 3% of its customer base to stand-alone power systems (SAPS) and microgrids. In 2004, Great Britain introduced contestability for 'the last mile' for new network investment in brownfields and greenfield sites in, and now 80% of new residential connections are made through independent (commercial) network providers.

> **The core issue is whether distribution networks are still a monopoly service or whether they are contestable.**

The second use case is for DER to provide network services, especially easing congestion in existing grids, to reduce the need for augmentation and replacement of parts of the network. There have been a number of successful Australian trials that show DER can provide network services, including in Projects Networks Renewed, CONSORT, Edge, Edith and Symphony. In Great Britain, where about 20% of network areas are constrained, 'flexibility services' are being procured by each of the six distribution networks, earning DER owners up to GBP33/kW/year in some locations. For example, a 10kW home battery can earn up to GBP331/year. Flexibility services are also procured from businesses such as water utilities which have control over their pumping and other electricity uses. By August 2023, 2.4GW of flexibility services had already been contracted by distribution networks in Great Britain for the 2023/24 year.

Internationally there is momentum towards reform of the economic regulation of electricity networks, with Great Britain the most advanced. This report looks at international case studies of network revenue reform across three themes and what Australia can learn from them:

- Totex regulation (total expenditure, combining capex and opex – operating expenditure) is widespread in Europe as a way of mitigating the risk of capex bias, but has not been taken up in the US.
- Network services procurement through DER and otherwise. It is widely recognised that DER can and will provide a greater proportion of network services. In Great Britain and Europe, network services provided by third-party DER (and larger-scale assets) are called 'flexibility services', while in North America, they are called non-wires solutions (or non-wires alternatives (NWA)).
- Performance incentive mechanisms (PIMs), including to support DER integration. These incentives are aligned with decarbonisation in many EU and US jurisdictions, but not in Australia.

Given the ten issues outlined with the current regulatory regime, and innovative overseas examples yielding improved outcomes for customers, **IEEFA recommends the Productivity Commission undertake a first-principles review of the economic regulation of distribution networks in the NEM.**

We recommend the review look to develop a form of economic regulation of distribution networks to achieve the following outcomes:

1. The best outcomes for consumers in terms of the lowest possible prices.
2. Economically efficient outcomes for our economy, including an end to capex bias.
3. Fast decarbonisation, including electrification, to achieve Australia's legislated emissions reduction goals.
4. A level-playing field between infrastructure and DER-provided network services.
5. Improved climate resilience.

IEEFA recommends the following questions be central to such a review:

1. What is the nature of contestability in distribution network services?
2. What outcomes should distribution networks be remunerated to provide?
3. How can and should distribution networks be rewarded for accelerating decarbonisation?
4. How can and should distribution networks be rewarded for innovation (including within and outside economic regulation)?
5. What processes can be used to efficiently determine network revenue, and in what timeframe given the fast-paced nature of the energy transition?
6. How can supernormal profits be avoided?
7. Should performance monitoring of network regulation and the regulator be introduced, and if so, what form should this take?

A review would identify ways to ensure efficient costs of distribution network services in a high-DER world. The significant medium-term benefit on offer would be lower proportional costs for consumers and improved economic efficiency, with consequences for Australia's overall economic productivity. If consumers were compensated for providing network services via DER, they could gain an enhanced return on their DER investments. Moreover, assuming the DER network costs are lower cost than infrastructure investment, costs would be reduced for all consumers. As Great Britain shows, contestable procurement of network services can be supported and facilitated by distribution network businesses.

High costs for electricity consumers have cost-of-living impacts and make Australian industry less internationally competitive. The combination of lower-cost renewable energy and more efficient network costs would be expected to provide the lower-cost electricity essential to Australia's future economic prosperity.

Part A. The building block model of economic regulation of distribution networks in the NEM

1. The history of the economic regulation of distribution networks

Deciding how much consumers should collectively pay electricity distribution networks for ensuring electricity is distributed to people's homes and businesses is a complicated matter.

Electricity distribution networks are the local 'poles-and-wires' companies that convey electricity from transmission network terminal stations through zone substations – the point where the high-voltage transmission network transforms down to the medium- and then low-voltage network – and on to the end users. They have traditionally been defined as monopoly infrastructure for the obvious reason that it is uneconomic to build multiple sets of poles, wires and substations.

> **Regulatory economists have debated the question of how to remunerate monopoly infrastructure since the late 19th century.**

The first modern monopoly infrastructure was train lines. Regulatory economists have debated the question of how to remunerate monopoly infrastructure since the late 19th century. How could regulation imitate the way a market works, in theory, through competition to create efficient prices for goods? How could a government body decide the price at which the marginal benefits to consumers were equal to the marginal costs for producers, when there were fixed, variable and borrowing costs for the owners and operators of monopoly infrastructure, and where it was impossible for regulators to have perfect information?

In the absence of competitive tension, the risk is that monopoly infrastructure owners will seek higher 'rents' for their service, and that labour unions will seek high wages and more desirable conditions, with lower economic productivity as a result. The counterargument is that, without sufficient investment or staffing, the monopoly service would fail to meet public needs – trains would not run on time – and social welfare would not be maximised, with flow-on consequences elsewhere in the economy. These are just some of the vexing interactions at the heart of regulatory economics.[2]

In the 1980s, Professor Stephen Littlechild was asked to develop a form of regulation for British Telecommunications (BT), in a few short weeks between 28 October 1982 and February 1983, before reporting to the British Secretary of State. BT would become the first of many public assets to be privatised under Prime Minister Margaret Thatcher's government.

[2] Productivity Commission. Electricity Network Regulatory Frameworks. Report No. 62. 9 April 2013. Chapter 3 – 'The rationale for regulation of electricity networks'.

Littlechild proposed that a regulated price be set for a service for a fixed period of time, usually five years.[3,4] The regulated company could increase that price by the rate of increase in the retail price index (RPI) minus $\mathcal{X}$, a negotiated factor representing anticipated productivity improvements (in excess of the national average for that firm). This meant prices would increase less than retail prices in general, and would be subject to negotiation between the firm and the regulator. In theory, prices could decrease where productivity was greater than the RPI, as would be appropriate.

The idea was that the $\mathcal{X}$ factor allowed productivity to be considered over and above straight 'rate of return regulation' – deciding what is an 'acceptable' profit (rate of return on capital invested) for running a particular monopoly service. It was also argued that because of the fixed regulatory period and the fact that each period is forward-looking, there is greater scope for bargaining with firms, and that political pressure on regulators to keep prices low would, if anything, risk underinvestment rather than over-investment in monopoly infrastructure.

Littlechild accepted the possibility that an initial forecast regulated revenue requirement could be incorrect and suggested this could be adjusted in subsequent regulatory decisions. In practice, a regulatory decision for British electricity companies and the water industry turned out to be overgenerous, allowing them high profits, and was reopened and amended in 1995 by Littlechild, who announced additional price cuts of about 10%.[5]

2. Economic regulation of distribution networks in the NEM

Australia has adopted a form of RPI-$\mathcal{X}$ regulation in electricity, gas, water, rail and communications.[6] The National Electricity Market (NEM) was created in the 1990s and electricity distribution networks were regulated first by state government regulators, and then by the new Australian Energy Regulator (AER), established underneath the Australian Consumer and Competition Commission (ACCC). The five Victorian and one South Australian (SA) distribution businesses were sold in 1994 and 2000 respectively, and more recently two of the three New South Wales (NSW) distribution businesses have been 51% privatised. Essential Energy and the Queensland distribution networks remain under government ownership (see Table 1).

[3] Edward Elgar Publishing. International Handbook on Economic Regulation. 27 June 2006. Chapter 2 – 'Economic Regulation: Principles, History and Methods'. *Martin Ricketts*.
[4] Department of Industry (UK). Regulation of British Telecommunications' Profitability - Report to the Secretary of State. 1983. *Littlechild, S.* Reprinted in Bartle (2003).
[5] World Bank Group. Has Price Cap Regulation of U.K. Utilities Been a Success? November 1997.
[6] Utilities Policy. Reflections on RPI-$\mathcal{X}$ regulation in OECD countries. December 2014. *Jonathan Mirrlees-Black*.

Table 1: Distributed network service provider (DNSP) ownership in the NEM

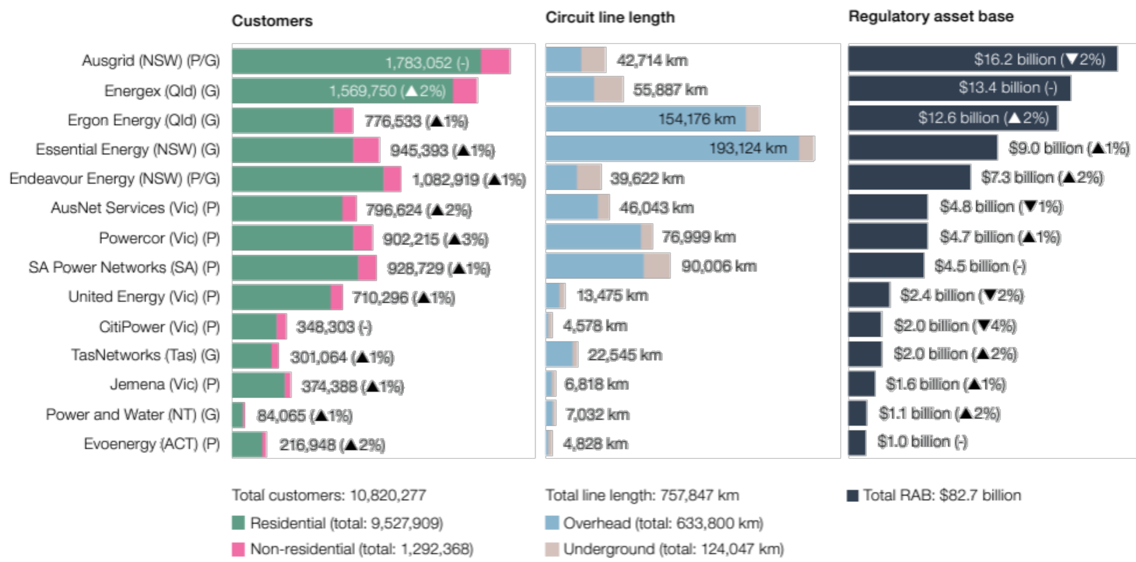
DNSP	Owners
South Australia (SA) Power Networks	Hong Kong-based Cheung Kong Infrastructure Holdings (51%); Spark Infrastructure (49%).
CitiPower and Powercor	Cheung Kong Infrastructure (CKI) (51%); Spark Infrastructure (49%).
United Energy	Cheung Kong Infrastructure (CKI) (66%); State Grid Corporation of China and Singapore Power joint venture (34%).
AusNet	Australian Energy Holdings No 4 Pty Limited, controlled by Brookfield Asset Management with co-investors including pension funds in Australia and Canada.
Jemena	60% owned by State Grid Corporation of China; and 40% by Singapore Power.
Ausgrid	49.6% owned by the NSW Government; 8.4% owned by AustralianSuper; 25.2% owned by IFM Investors; and 16.8% owned by APG Asset Management Group.
Endeavour Energy	50.4% owned by an Australian-led consortium of Macquarie Asset Management, Canada's British Columbia Investment Management Corporation, and Qatar Investment Authority.
Essential	NSW Government.
Ergon and Energex	Queensland Government.

Source: IEEFA, ownership details from each DNSP's website.

Together the 13 DNSPs in the NEM have 758,000km of overhead and underground lines servicing 10.8 million customers, with a regulatory asset base (RAB), the total value of the poles, wires and substations, of AU$82.7 billion (see Figure 1).[7]

[7] AER. State of the energy market 2023. 5 October 2023.

Figure 1: Electricity networks regulated by the AER – distribution



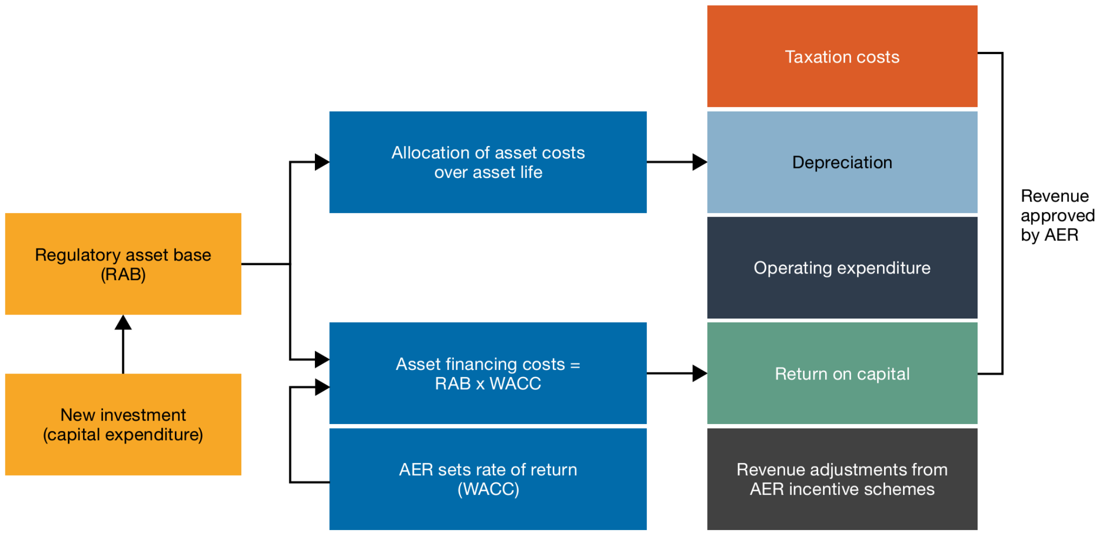
Note: (G): state government owned; (P): privately owned; GWh: gigawatt hours; km: kilometres; % values represent change from previous year. Regulatory asset base is adjusted to June 2022 dollars. Line length and regulatory asset base are as at 30 June 2022 (31 March 2022 for AusNet Services transmission). Electricity transmitted is for the year to 30 June 2022 (year to 31 March 2022 for AusNet Services). Customer numbers, line length and asset base are as at 30 June 2022 for the distribution networks. For regulatory purposes, Northern Territory transmission assets are treated as part of the distribution system. Energy delivered is a measure of total energy transported through the transmission networks. The information reported includes energy delivered to distribution networks, pumping stations and directly connected end users. Energy delivered to other transmission networks is included in the data for individual transmission network but has been excluded from the total.

Source: AER.

In Australia the RPI-$\mathcal{X}$ regulation is also referred to as a 'building block' model. The blocks of the AER's revenue determinations decisions are shown in Figure 2:

1. Taxation liabilities.
2. Regulatory depreciation of assets costs.
3. Operating and maintenance expenditure.
4. Return on capital (weighted average cost of capital (WACC) times value of the RAB).
5. Efficiency incentives under the Efficiency Benefits Sharing Scheme (EBSS – for opex) and the Capital Efficiency Sharing Scheme (CESS – split notionally 30:70 between networks and consumers); and performance incentives (direct rewards to DNSPs) including the Service Target Performance Incentive Scheme (STPIS), the Demand Management Incentive Scheme (DMIS), and a new Customer Service Incentive Scheme.

Figure 2: The building blocks of electricity network revenues



Note: AER: Australian Energy Regulator; RAB: regulatory asset base; WACC: weighted average cost of capital.
Revenue adjustments from incentive schemes encourage network service providers to efficiently manage their operating and capital expenditure, improve services provision to customers and adopt demand management schemes that avoid or delay unnecessary investment.

Source: AER.[8]

The AER determines DNSP revenue by state every five years on a rotating basis. It publishes a 'Framework and Approach' paper at the commencement of each determination process.[9] This sets out:

- The incentive schemes that will apply to, for example, service quality, improvements in network reliability, or capital and operating expenditure.
- The AER's approach to setting efficient expenditure allowances and the establishment of the opening RAB for the upcoming regulatory control period.
- For DNSPs, the services covered by the revenue determination, and the form of regulation that will apply to them.

Each distribution business then submits a lengthy series of documents proposing its revenue requirements over the five years of the determination. The AER responds and issues a draft determination. The DNSP then revises its revenue proposal, and the AER makes a final revenue decision. Hence the process is known as a 'propose-respond' model.

Technically, because this economic regulation meets the definition of performance based regulation (PBR) because has the following features:

[8] AER. State of the energy market 2023. 5 October 2023. Page 86.
[9] For example, see: AER. AER publishes final Framework and Approach papers for Ergon Energy, Energex, SA Power Networks and Directlink. 3 July 2023.

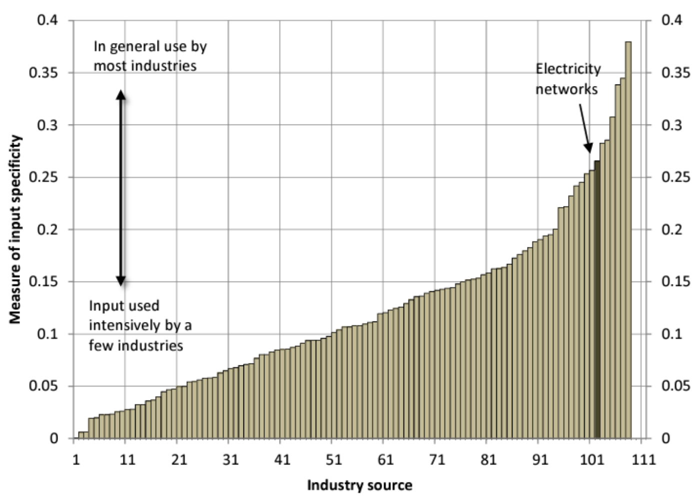
- **Multi-Year Rate Plans** – revenue set for a predetermined regulatory period.
- **Efficiency Sharing Mechanisms** – which specify how the rewards of efficiency improvement by the utility should be distributed between itself and its customers.
- **Performance Incentive Mechanisms (PIMs)** – rewards for specific outcome achievements. [10]

In practice however, NEM network revenue has not tracked network performance against outputs for consumers, as this report will outline.

3. Why electricity networks matter for economic productivity

Although Australia is primarily a services-based economy, the Productivity Commission stated in the final report in its 2013 inquiry into electricity network regulatory frameworks that "of all industries that supply inputs to other industries, network services are characterised by close to the most uniform pattern of use" (see Figure 3).[11]

Figure 3: Network services are general-use inputs



a The measure of specificity is calculated as follows. Let there be N industries. Define an input share (α) each industry in the total intermediate inputs (TotalUse) of each other industry:
$\alpha_{jk} = \mathrm{Input}_j / \mathrm{TotalUse}_k$ for $j, k \in (1 \dots N)$

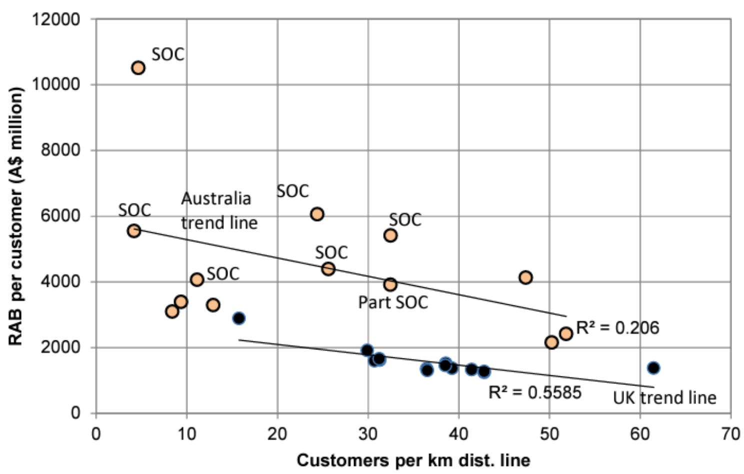
For any given industry (m) in the group 1 to N, there will be a vector of alpha values ($\mathbf{V_m}$) representing the importance of that industry as an input into other industries ($\alpha_{m1}, \alpha_{m2}, \alpha_{m3}, \dots \alpha_{mN}$). Calculate the ratio ($R_m$) of 20th and 80th percentiles of $\mathbf{V}_m$. Were a given input industry to account for one per cent of the total intermediate use of each other industry, then R_m =1. That means that industry m would be a general-use input. In contrast were R_m to be small then it implies that many industries make little use of that input and some a large amount — a high level of specificity. The data show that electricity network services are a general-use input (though typically a small share of each industry's total inputs – as shown in figure 2.7). Indeed, it is close to being the most general-use input among the large group of industries covered by the ABS input-output tables.

Source: Productivity Commission.

[10] MIT Center for Energy and Environmental Policy Research (CEEPR). The Expansion of Incentive (Performance Based) Regulation of Electricity Distribution and Transmission in the United States. January 2024. *Paul L. Joskow.*
[11] Productivity Commission. Electricity Network Regulatory Frameworks. Report No. 62. 9 April 2013.

Electricity distribution networks matter because their costs account for 30%-40% of electricity bills and electricity is a major input into many industries and a major cost-of-living issue for households.[12] If Australia's electricity prices are above those of our trading partners, this puts Australian exporters at a cost disadvantage. The Productivity Commission explored this issue through a comparison of the RAB value per customer in Australia and Great Britain. Below, Figure 4 shows how customer density is generally lower in Australia than in Great Britain, but that the RAB per customer is also higher, taking this difference into account.[13]

Figure 4: Australian versus British asset bases per customer



[a] Note the importance of taking care when interpreting RABs, as discussed in section 6.4 of this chapter. Purchasing power parities have been used to convert currencies. SOC denotes a state-owned corporation.

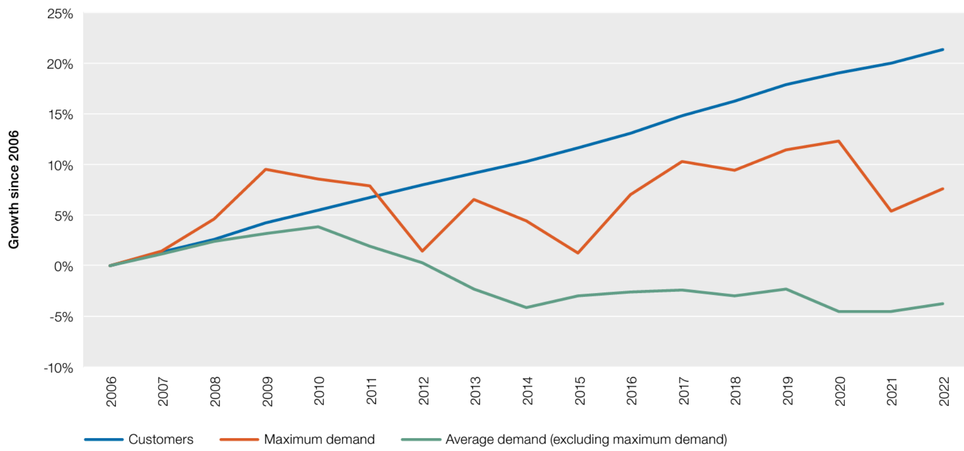
Source: Productivity Commission.

4. How is utilisation of distribution networks changing?

Overall, NEM-wide maximum operational demand has grown much slower than customer numbers (see Figure 5). Average demand has fallen about 5% since 2006, while customer numbers have grown about 22%.

[12] Up-to-date figures are not currently available due to the delay in the Australian Energy Market Commission (AEMC)'s residential price trends report, which will next be released in late 2024.
[13] Productivity Commission. Electricity Network Regulatory Frameworks. Report No. 62. 9 April 2013.

Figure 5: Growth in customers and demand – electricity distribution networks



Note: Maximum demand is the network sum of non-coincident, summated raw system maximum demand (megawatts). Non-maximum demand is the total energy delivered (gigawatt hours) for the year, excluding the energy delivered at the time of maximum demand divided by hours in the year minus one. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER.[14]

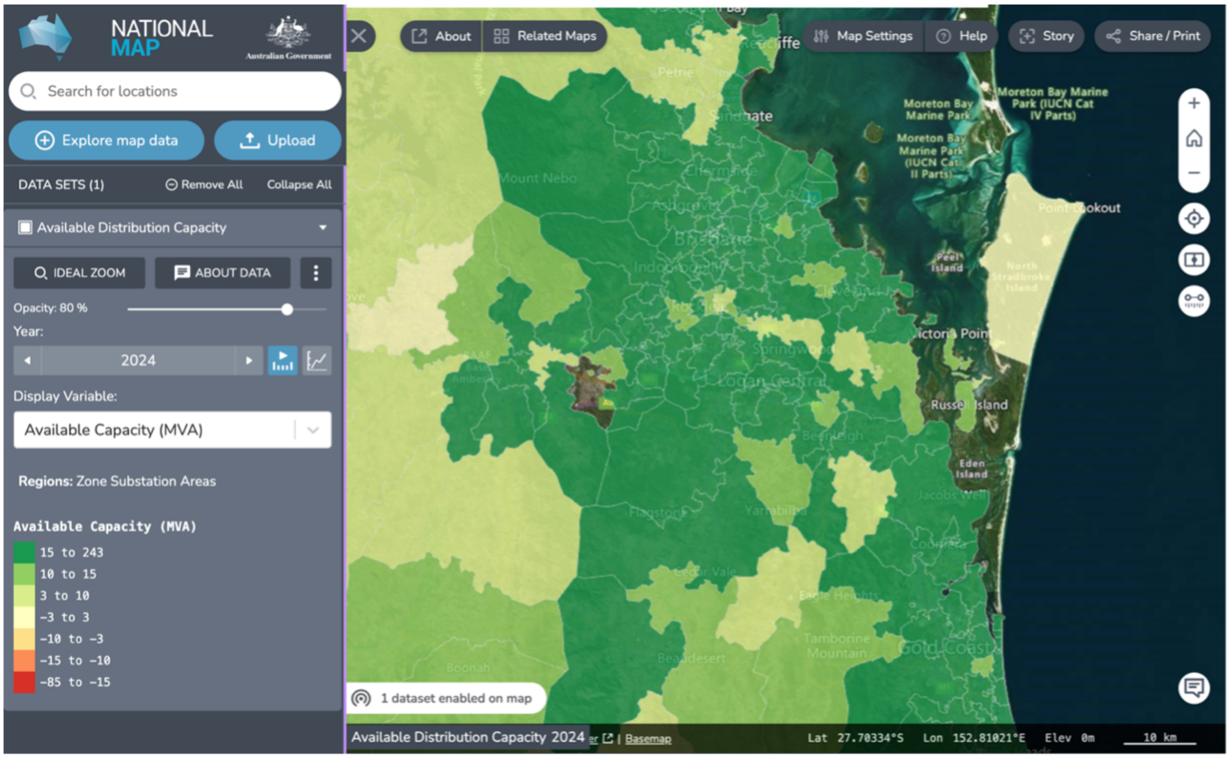
This highlights that average annual and maximum demand per connection (i.e. per customer) has decreased substantially since around 2010.[15] This has occurred against a background of widespread excess network capacity due to historical over-investment, alongside widespread adoption of distributed energy resources (DER) including improving appliance and building efficiency, as well as rooftop solar. Therefore, it follows that most demand growth and network congestion reflect new connections driven by population and other economic growth, not changes in the demand behaviour of existing connections.

This can, for example, be observed in the resulting available zone substation capacity presented in the Network Opportunity Maps developed by UTS and Energy Networks Australia (ENA).[16] Figure 6 below shows a screenshot of the 2024 zone substation capacity for Brisbane and the Gold Coast, which shows very few constrained regions.[17] Examining these maps for the NEM, as well as reviewing distribution annual planning reports, only regions with multiple orange or red zones – that is, more than 10 megavolt-amps (MVA) of constrained capacity – in parts of Adelaide, Melbourne and regional Victoria are experiencing substantial increases in connections from population increases or new industrial developments. This is evident from reviewing regulatory investment test (RIT-D) proposals for network augmentation in Victoria or elsewhere.[18] Most augmentation RIT-Ds

[14] AER. State of the Energy Market 2023. October 2023.
[15] See also flat or falling operational demand across most of the NEM, as noted in the AER's State of the Energy Market 2023 report. Page 55, Figure 3.15.
[16] ENA. Network Opportunity Maps.
[17] National Map. Network Opportunity Maps, developed by UTS and ENA.
[18] CitiPower and Powercor Australia. Network data.

are associated with urban intensification, urban fringe development and industrial zone development. This is also evident in Ausgrid's Distribution and Transmission Annual Planning Report (DTAPR).[19]

Figure 6: Network Opportunity Map for Brisbane and the Gold Coast in 2024

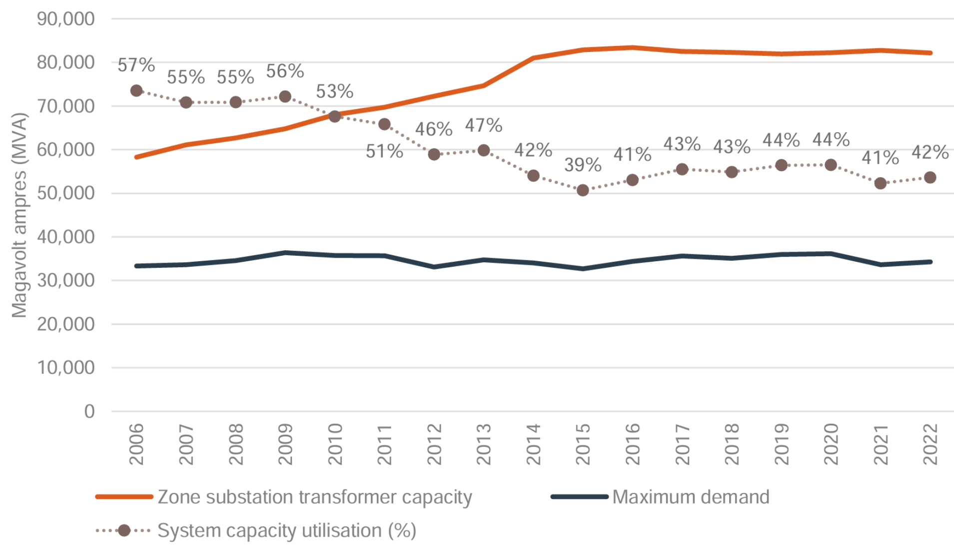


Source: National Map.

Network utilisation figures allow for the dynamics at the substation level to be accounted for. Network utilisation as shown in Figure 7 is the ratio of reported non-coincident maximum demand (MVA) at the zone substation level, to the zone substation transformer capacity (MVA). This figure looks at the load when each geographic point experienced maximum demand, not at the same time, and compares that to the available capacity. Figure 7 shows that in 2022 it was 42%, having been falling or flat since 2006 when it was 57%.

[19] See for example Ausgrid's discussion of proposed augmentation projects: Ausgrid. Distribution and Transmission Annual Planning Report. December 2023.

Figure 7: Total distribution network utilisation



Source: (a) Non-coincident summated raw system annual maximum demand from EB RIN table 3.4.3.3 – Annual system maximum demand characteristics as the zone substation level – MVA measure. (b) Zone substation transformer capacity from EB RIN table 3.5.2.2.

Notes: System capacity utilisation is an AER calculation of (a) ÷ (b).

Source: AER.

As the AER states that "lower utilisation in combination with relatively stable load profiles can mean consumers are paying for network assets they rarely use. If utilisation is inefficiently low, consumers will be paying more for excess capacity than the value of the benefits they gain from it."[20]

This is not a necessary feature of network regulation. As discussed below, prior to 2006 and in other jurisdictions, excess regulated investment can result in RAB write-downs.

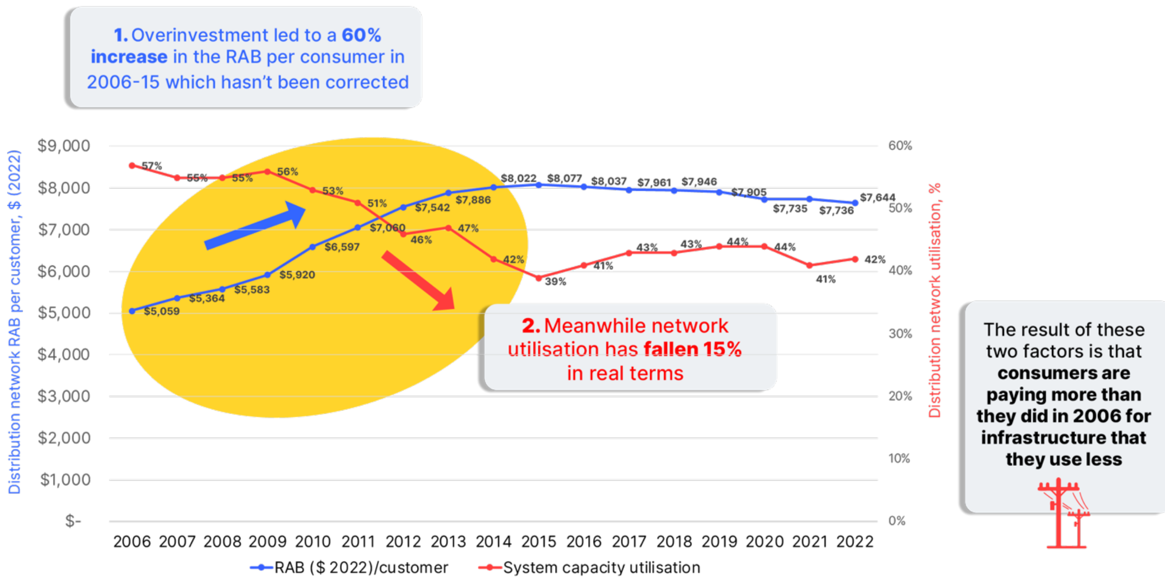
Based on AER data, we can conclude that:

- The raw value of the distribution network RAB increased 46% or AU$38.4 billion real (2022 dollars) to AU$81.7 billion from 2006-2022, and 14% or AU$11.2 billion real (2022 dollars) from 2012-2022.[21]
- The *per-customer* increase in the combined value of the all the NEM DNSPs' RABs was 60% over 2006-2015, 34% across 2006-2022 and 1% over the period 2012-2022.
- Meanwhile, network utilisation has fallen 15% in absolute terms and 26% in proportionate terms from 2006-2022.[22]

[20] AER. Electricity network performance report 2023. July 2023.
[21] IEEFA calculations based on AER network performance data.
[22] IEEFA calculations based on AER network performance data.

These figures suggest that while RAB growth per customer has stabilised, network utilisation has not improved, and that the RABs are still over-valued, as a result of historic excessive investment, as the ACCC stated in its 2018 Retail Electricity Pricing Inquiry.[23] The fact that over 2006-2022, per-customer RAB rose 34% and network utilisation fell 26% in comparison with 2006 levels (15% in absolute terms) suggests some sort of course correction is required (see Figure 8).

Figure 8: Distribution network RAB per customer vs utilisation, 2006-2022



Source: IEEFA.

The ACCC's analysis of the excessive investment period suggested "that customers were getting decreasing value for money from networks over the same period that the significant investment was taking place".[24] Therefore, the ACCC considered that, "from an electricity standpoint there are clear affordability and efficiency gains to be made from an explicit writedown made now … a writedown should be viewed as a way of limiting the extent to which customers continue to pay for investment that has turned out to not be useful, and of improving economic efficiency."[25]

Recommendation 11 of the ACCC's review was:

"The governments of Queensland, NSW and Tasmania should take immediate steps to remedy the past over-investment of their network businesses in order to improve affordability of the network.

"With appropriate assistance from the Australian Government, this can be done:

- in Queensland, Tasmania and for Essential Energy in NSW, through a voluntary government write-down of the regulatory asset base

[23] ACCC. Retail Electricity Pricing Inquiry—Final Report. June 2018.
[24] ACCC. Retail Electricity Pricing Inquiry—Final Report. June 2018. Page 160.
[25] Ibid. Page 169.

- in NSW, where the assets have since been fully or partially privatised, through the use of rebates on network charges (paid to the distribution company to be passed on to consumers) that offset the impact of over-investment in those states.

"Such write-downs would enhance economic efficiency by reducing current distorting price signals. The amount of the write-downs and rebates should be made by reference to the estimates of over-investment by the Grattan Institute, and should result in at least $100 a year in savings for average residential customers in those states."[26]

What is needed, six years on, and after these write-downs did not occur, is better measurements and analysis of network utilisation based on the understanding that the distribution grid is now providing for both imports and exports. We also need to understand the likely increases in use of the distribution networks because of the electrification of gas use in homes and businesses, and the electrification of transport. These dynamics need to be thoroughly investigated to see if the ACCC analysis and its calls for write-downs are still valid.

> **These dynamics need to be thoroughly investigated to see if the ACCC analysis and its calls for write-downs are still valid.**

Having outlined the nature of the existing economic regulation and its outcomes in terms of distribution network asset growth and declining network utilisation, this report will now examine a range of related issues in the economic regulation.

Part B. Major challenges with the existing economic regulation

5. The fundamental issue of economic regulation theory: are distribution networks becoming contestable?

This report began with a discussion of the development of economic regulation for monopoly infrastructure. When mobile telephony was commercialised, landlines were no longer fully monopoly infrastructure, and increasingly became less so, and their economic regulation had to evolve. Currently more than 3 million Australian households generate part or all of their electricity supply behind-the-meter (BTM). With batteries, and especially with electric vehicles (EVs) with vehicle-to-home (V2H) bi-directional charging, consumers will be even less dependent on the distribution network. It will be economic for many remote consumers to go 'off grid', and perhaps even for some regional consumers to do so.

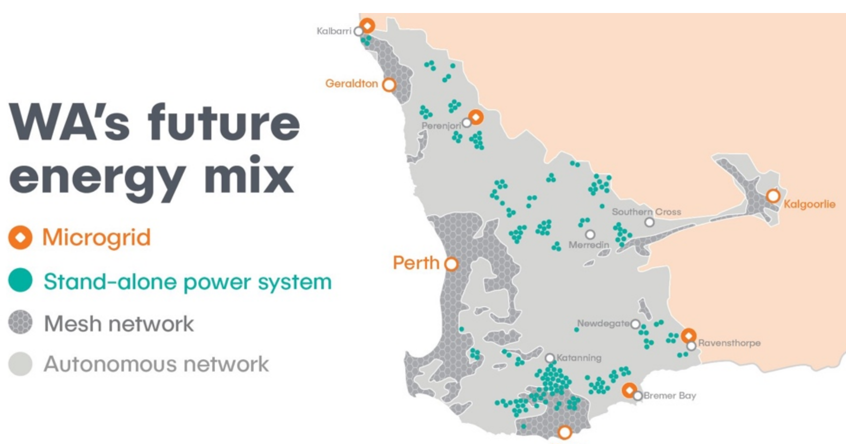
[26] ACCC. Retail Electricity Pricing Inquiry—Final Report. June 2018. Page xviii.

In Western Australia (WA), where the NEM law and rules do not apply, Western Power has gone through an extensive forward planning process over the last few years. Through this process, Western Power decided to **convert more than 52% of the network, which serves less than 3% of its customers in remote areas, to stand-alone power systems (SAPs) and separate or isolatable microgrids as an 'autonomous network'** (see Figure 9) below. As a result, Western Power is progressively decommissioning Single Wire Earth Return (SWER) lines in these regions once the SAPs and microgrids are in place.[27,28,29,30] Western Power is using DER to provide network services. Even when there is no connection to the rest of the network, consumers will pay a network charge to Western Power for delivery of distribution network services by alternative means.

No distribution networks in the NEM have undertaken equivalent analysis or planning, even though due to postage stamp pricing, there are large cross-subsidies between urban and rural areas of distribution grids. For example, "the Under the Uniform Tariff Policy, the Queensland Government subsidises the cost of electricity supply to regional Queensland through Community Service Obligation (CSO) payments to Ergon Energy Retail and Origin Energy (for customers in the Goondiwindi-Texas region). In 2023–24 the Queensland Government budgeted more than $541 million for the CSO, including approximately $90 million for isolated communities."[31]

A vital question for any review of the economic regulation of distribution networks is what form of economic regulation would allow for a reduction in these large cross-subsidies given the potential to provide electricity cheaper and more reliably in remote and regional areas through SAPS and microgrids?

Figure 9: Western Power's plans for WA's electricity network



Source: Western Power

[27] Western Power. The future of the grid: What is it made up of?.
[28] Western Power. Future of the grid.
[29] Western Power. The future of the grid: What is it made up of?.
[30] Energy Networks Australia. WA drives smart grid solutions.
[31] Queensland Government. Understand the electricity supply system. 2024.

As well as replacing traditional distribution networks in remote areas, DER can substitute for augmentation or replacement within existing networks, for example, easing congestion on demand. As discussed in detail in the international case studies later in this report, the provision of network services is well established in Great Britain (where it is known as flexibility procurement), and it is emerging in a number of other European countries and parts of the US where it is called 'non-wires alternatives' or 'non-wires solutions' procurement. There have been trials of household DER providing network services in Australia, with Projects Networks Renewed, CONSORT (Bruny Island Battery Trial), Edge, Edith and Symphony, and a 'flexibility services' pilot in WA using commercial and industrial customers' DER.[32,33,34,35,36]

Consumers want to pay for a reliable service, not necessarily for infrastructure. Consumers want heat and light and powered phones and laptops, but they are generally indifferent about how the electrons are supplied. Where network services are provided by DER, consumers are unlikely to be even aware this is happening.

Harnessing DER to provide network services is usually cheaper than building infrastructure because it uses existing assets (paid for by consumers) with only software and occasionally additional hardware (such as Home Energy Management Systems (HEMS) and smart meters) needed to unlock their coordination. In addition, owners of DER can be paid for providing these network services, increasing their return on investment and reducing all consumer bills. This could reallocate revenue from distribution networks to DER owners.

Energy Networks Australia (ENA, the peak industry body) and CSIRO's 2017 Electricity Network Transformation Roadmap forecast $16 billion in avoided network infrastructure investment by 2050 as a result of orchestration of DER to provide network services. This modelling also forecast distribution networks would be **paying DER owners more than $2.5 billion per annum for grid support services by 2050**.[37]

Based on now conservative figures for DER uptake, Baringa estimated AU$10 billion in distribution network investment could be avoided by 2040 through efficient DER integration, including the use of DER to provide some network services under the 2020 Integrated System Plan Step Change scenario.[38]

In addition, there's the possibility of creating 'last mile contestability', as exists in Great Britain. In 2004, Great Britain's energy regulator, the Office of Gas and Electricity Markets (Ofgem) first

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32 UTS Institute for Sustainable Futures. Networks Renewed. October 2019.
33 CONSORT Bruny Island Battery Trial. CONSORT (Bruny Island Battery Trial). 2019. Note: CONSORT was a collaboration between Australian National University, University of Sydney, University of Tasmania, TasNetworks and Reposit Power.
34 ARENA. DEIP DER Market Integration Trials Summary Report. September 2022.
35 Energy Security Board. Consumer energy resources and the transformation of the NEM - Critical priorities to support transformation: a call to action. 12 February 2024.
36 Western Power. Flexibility Services Pilot. 2022.
37 CSIRO and ENA. Electricity Network Transformation Roadmap: Final Report. April 2017.
38 Baringa Partners. Potential network benefits from more efficient DER integration. 18 June 2021.

allowed independent distribution network operators (IDNOs) to "operate electricity distribution networks which will predominantly be network extensions connected to existing distribution networks, e.g. to serve new housing developments on both greenfield and brownfield sites". They now serve about 1.5 million customers in Great Britain and are responsible for about 80% of new residential connections.[39]

Unlike the 14 geographically based distribution network operators (DNOs, equivalent to Australian DNSPs), IDNOs are not restricted to a geographical region and can operate across Great Britain. This goes above and beyond the Australian concept of embedded networks, because the IDNOs pay discounted distribution tariffs to the distribution network reflecting the fact that they are providing 'last mile' distribution services. Voluntarily, the Independent Networks Association has developed a Low Voltage Design Standard, which requires homes to be energy-efficient and provide for EV charging.[40]

There is potential to create efficient electric precincts in both greenfield and brownfield areas that optimise energy supply, demand and storage at lower cost than traditional network build.[41] It is also possible that third parties could deliver new distribution services faster than DNSPs. **IEEFA suggests that the Productivity Commission considers the potential of creating 'last mile contestability' within the economic regulation in the interests of economic efficiency, decarbonisation and innovation.**

If DER are substituting for network upgrades or augmentation, it would mean there is at least partial contestability in distribution network services. The poles, wires and substations are still necessary in most cases. However, if there is that kind of substitution – for example, behind-the-meter batteries providing the same service as an upgraded transformer – is a distribution network still a pure monopoly? Maybe, in the sense the DNSP (a monopoly provider) is procuring those services, but maybe not, in that there are now multiple ways to provide a network service. These are issues worthy of a first-principles review.

In preparing this report, IEEFA consulted Dr Ron Ben-David, Professorial Fellow with the Monash Business School. Given the rapidly changing energy landscape, Ben-David stated: "The primary question that must be answered is how do we define what we mean by networks, network services, consumers of network services, producers of network services, and network operators (including distribution service operators)? Until those core concepts are defined, regulation is destined to continue on its incrementalist (or whack-a-mole) approach because it is groping around in the dark. As a result, risks will be misallocated and mispriced – or to put it bluntly, consumers are going to cop it in the neck."

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[39] Ofgem. Open letter on regulatory arrangements for independent distribution network operators. 19 October 2023.
[40] Independent Networks Association. Low Voltage Design Standard. 2023.
[41] Green Building Council of Australia. The future is electric: A practical guide for grid-optimised precincts. 2024.

Therefore, the fundamental questions for regulatory economists to investigate are:

- To what extent is the provision of distribution networks now a contestable i.e. competitive service?
- If distribution networks are no longer fully a monopoly, how should they be regulated?
- In particular, how can regulation create a level playing field for procurement of network services by (usually expensive) substation upgrades, poles and wires and coordinated DER?
- If DER are to provide network services, how can effective competition and efficient pricing be created? For example, could retailers participate in any market or contracting for network services?
- Should DER be able to be included in the RAB (what is in the US called 'rate basing')? To what extent should it be able to be included if a DER is being used to provide multiple services?

Professor Ross Garnaut, also consulted in the preparation of this report, suggested the following flow-on questions:

- How big would the RAB be if we designed the system for contemporary technological circumstances, the rise and optimum use of decentralised storage and solar?
- To what extent should the NEM follow the Western Power 'modular network' model and replace low reliability services (poorly performing assets) in remote and regional Australia with SAPs and microgrids?
- How much would that change the size of the RAB?
- Should we write down any of the established investment in the distribution system and confine new investment to what makes sense in the new world?
- Would that substantially reduce costs to users?
- How would you distribute the costs of the write-down between government and current system owners?

Then there is the complicating question as to how the electrification of gas appliances and vehicles might impact the answers to all these questions. Will a doubling of electricity demand reverse the decline in network utilisation and soak up all the available grid capacity? This is discussed further below.

6. Suggestions of capex preference in DNSP expenditure decisions

Several reports and reviews have suggested that an outcome of the economic regulation of DNSPs and how it is administered is a bias towards capital investment and therefore increasing the size of the RAB.[42,43,44,45] In economic theory, the Averch-Johnson (A-J) effect predicts the introduction of rate of return regulation will increase the capital intensity of production methods.

Professor Ross Garnaut raised concerns about distribution network revenue regulation in his 2011 Review for the Commonwealth Government, writing of the increases in distribution network costs occurring at the time, 'These investments have been stimulated by a regulatory regime that provides excessive incentives for investment whether or not it is wanted by consumers'.[46] This fundamental feature of the regulatory regime is still in place 13 years later.

> **These investments have been stimulated by a regulatory regime that provides excessive incentives for investment whether or not it is wanted by consumers.**

A 2018 report by KPMG listed the factors that create barriers to networks making efficient expenditure decisions, including:

- Differences in the regulatory treatment and certainty of cost recovery between opex and capex. For example, the rules guarantee the recovery of capex, as long as it is below the total regulatory allowance, which does not apply to opex, where the AER can reassess expenditure every five years.
- The WACC (weighted average cost of capital), a commercial rate of return applied to capex – so an actual capex financing cost lower than the granted WACC will result in profits that are a compensation for equity risk. KPMG gives the example where a 1% lower rate of finance than the approved WACC could generate up to AU$150 million in annual profits for networks. The question is whether the compensation for risk is set appropriately.
- Capex returns are based on the size of the RAB (a cumulative spend) as opposed to opex, which is remunerated on a current basis. As KPMG highlights, if the rate of allowed return is equal to the cost of equity capital, this would not be an issue, "But the incentives to achieve financing

[42] Cambridge Economic Policy Associates. Expenditure incentives faced by network service providers. 25 May 2018. Final report for the AEMC.
[43] AEMC. Economic Regulatory Framework Review – Integrating Distributed Energy Resources for the Grid of the Future. 26 September 2019.
[44] KPMG. Optimising Network Incentives. 2018.
[45] Department of Climate Change, Energy, the Environment and Water. Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future. 9 June 2017.
[46] Prof. Ross Garnaut. The Garnaut Review 2011. Page 150. 2011.

efficiencies and regulatory asset base (RAB) growth are having an important influence in both business planning and delivery".[47]

- That the operationally 'easier' network investment option may win out over the more unfamiliar and time-intensive non-network alternative project, even if the returns are comparable.
- Risk assessment and mitigation within DNSPs can also drive inefficient expenditures.[48]

The ACCC was also concerned about possible capex bias and highlighted that under the national gas law any capex could be assessed for 'redundancy', but that this provision does not exist in the national electricity law. The 2018 ACCC report details the history whereby:

"The ACCC initially expressed a view that it would seek to apply a depreciated optimised replacement cost (DORC) methodology whereby the value of assets were revised from time to time to reflect the depreciated cost of assets of the system as if it had been reconfigured so as to minimise the forward looking costs of service delivery. It also proposed that only capital expenditure deemed to be prudent expenditure of a network operator 'acting efficiently in accordance with good industry practice and to achieve the lowest sustainable cost of delivering services' could be rolled into the asset base. It proposed to review expenditure at the end of the regulatory period.

"The ACCC subsequently in 2004 revised its view on the use of the DORC methodology, preferring a mechanism that did not use periodic revaluations. It instead preferred an approach whereby the RAB was 'locked in' at the end of a regulatory period and carried forward to the next period. It also preferred an approach whereby actual capital expenditure was rolled into the asset base, rather than a deemed efficient amount of expenditure, along with the use of incentives to encourage efficient capital expenditure."[49]

Prior to the creation of the NEM, distribution businesses faced potential RAB optimisation by state regulators if they were found to have over-invested in capacity.[50] However, energy ministers decided instead to shift to the 'roll-forward' of the RAB.[51]

Ultimately the ACCC in 2018 again decided against recommending the adoption of a DORC method on the grounds of regulatory risk, the challenge of the assessment process and the lack of certainty of reduced costs. However, it did recommend: "The National Electricity Rules should explicitly allow for a process whereby network assets may be stranded and the costs of that stranding is shared between users and networks. The [Australian Energy Market Operator] AEMC should determine the definition of 'stranding' and how the costs of 'stranding' can be shared."[52]

[47] KPMG. Optimising Network Incentives. 2018. Page 14.
[48] KPMG. Optimising Network Incentives. 2018.
[49] ACCC. Retail Electricity Pricing Inquiry—Final Report. June 2018. Page 157.
[50] For a discussion of network asset optimisation, see: Independent Pricing and Regulatory Tribunal of New South Wales. Electricity Prices. March 1996. Page 6.
[51] This is informed by, for example, Allen Consulting Group. Methodology for updating the regulatory value of electricity transmission assets. Final report to the Australian Competition and Consumer Commission. August 2003.
[52] ACCC. Retail Electricity Pricing Inquiry—Final Report. June 2018. Page 172.

In 2017, the ENA-CSIRO Electricity Network Transformation Roadmap was released and recommended that a totex (total expenditure) approach be trialled by 2018 and adopted as the default approach by 2027. The Roadmap states: "Under a TOTEX approach, regulated networks would be given a single operating and capital investment allowance, driving least cost outcomes for consumers, and removing any potential bias towards expensive capital investment solutions. TOTEX would also better align incentives between customers, networks and third party providers in the deployment of efficiently scaled distributed energy resources."[53]

A totex approach would mean a network's revenue would not vary with its mix of capital and non-capital inputs. Therefore, there is an incentive on the company to substitute a capital-reducing DER for a more capital-intensive technology when (and only when) the former reduces the company's total cost of production. In addition, it equalises the incentive for spending on opex such as software, algorithms, communications platforms and digital tools, which can assist in making distribution networks 'smarter'.

> **A totex approach would mean a network's revenue would not vary with its mix of capital and non-capital inputs.**

In 2018, as part of its first review of the electricity network economic regulatory framework (ENERF), the AEMC published a report by Frontier Economics that surveyed the use of totex in several jurisdictions, including Great Britain, Germany, the Netherlands, and in Victoria during the early 2000s.[54]

However, despite the support of ENA for totex, the AEMC was equivocal, stating that: "Expenditure assessment and remuneration, while an important aspect, is not the only part of the framework. Changes to this part alone may not be sufficient to promote efficient network investment in a transforming system; nor is it likely that a different approach such as a total expenditure framework (totex) alone would resolve every issue and challenge faced by the electricity sector as it continues to transform."[55]

AEMC's overarching conclusion was that the "the fundamental features of the economic regulatory framework remain appropriate and that an overhaul of the current regulatory arrangements is not warranted at present".[56] The AEMC has not recommended any significant changes to the economic regulation, including through three years of ENERF reviews which suggests it is not a suitable body to conduct a first-principles review of the economic regulation in the NEM.

[53] ENA patterned with CSIRO. Electricity Network Transformation Roadmap. April 2017. Page 49.
[54] Frontier Economics. Total expenditure frameworks. December 2017
[55] AEMC. Economic regulatory framework review 2018. 26 July 2018. Pages 104-105.
[56] Ibid. Page iv.

7. The risk of repeating the 2006-2015 over-investment

Australia is ahead of the rest of the world on the integration of rooftop solar, but there is a danger that under the current regulation, distribution networks will be tempted to spend more capex, rather than use DER to provide network services. In addition, there is the risk of over-investment as a result of electrification, especially of vehicles.

Consultant Matt Rennie is already arguing that: "The next 15 years will rival the N-1 period between 2004 and 2012 in terms of required network investment to handle household EVs and DER and retrofitted batteries in the zone and poletop transformer ecosystem, and the large scale network strength to handle the serious MW required for inset C&I charging."[57]

This is concerning in terms of the potential increases in costs for consumers.

Queensland and SA DNSPs submitted 2025-30 revenue proposals to the AER in January 2024.[58]

South Australia has about 45% of households with rooftop solar and a growing number of households with batteries, and SA Power Network's area is home to one of the largest virtual power plants (VPPs) in the NEM.[59] Over the period, in real 2025-dollar terms in comparison to the previous 2020-2025 regulatory period, SA Power Networks is proposing:

- A 21% increase in capital expenditure (including AU$506 million in network augmentation).
- An 18% increase in operating expenditure.
- An 8% increase in revenue.

In Queensland, an estimated 46% of households – one million – have rooftop solar totalling more than 4 gigawatts (GW) of capacity.[60,61] Ergon is proposing:

- A 20% increase in capital expenditure.
- A 0.1% increase in operating expenditure.
- A 15% increase in revenue.
- A 32% increase in the value its RAB.

Energex is proposing:

- A 22% increase in capital expenditure.

[57] Matt Rennie. LinkedIn post. April 2024.
[58] All figures from the revenue proposals on the AER's website.
[59] Percentage of houses with a PV system by State/Territory from Australian PV Institute. Mapping Australian Photovoltaic installations. May 2024.
[60] RenewEconomy. Sunshine State milestone as Queenslanders install one million solar rooftops. 18 January 2024.
[61] Australian PV Institute. PV Postcode Data. 2024.

- A 6.8% decrease in operating expenditure.
- A 18% increase in revenue.
- A 15% increase in the value its RAB.

All dollars in 2024-25 dollars in comparison with the previous 2020-2025 regulatory period.

The AER will decide the legitimacy of these proposals, but on face value, it seems surprising to propose such large expenditure increases given network utilisation is flat or falling and rooftop solar installations are continuing to increase.

In addition, the extent of any increase in demand due to electrification and the extent to which that might cause an increase in peak demand requiring additional network investment is currently unclear, particularly because good coordination could prevent electrification loads adding to peak demand, and rooftop solar with storage can reduce network peaks.[62,63,64] Any over-investment in networks in the electrification era risks undermining at least some savings on offer from electrification.

8. Supernormal profits from implementation of building block regulation with no system for monitoring its effectiveness

In an IEEFA report from November 2023, guest contributor Simon Orme estimated that from FY2014-FY2022, AU$11 billion of supernormal profits were extracted across all electricity transmission and distribution networks, on top of an allowed profit of AU$16.[65] Orme found electricity networks extracted AU$2 billion of supernormal profits in FY2022 – making total profits 2.5 times the levels necessary to compensate shareholders for risk.

In response, the AER stated: “We derive a similar outcome to IEEFA with a return on equity of $9.7 billion out of total revenue of $122 billion ($2022, real). The difference is that our estimate uses the actual leverage of the networks businesses as opposed to average gearing across networks used by IEEFA.”[66]

The AER asserted that this gap of around AU$10 billion between actual and allowed returns profits is “consistent with the National Electricity Law (NEL) and National Energy Objective (NEO)”, because the “regulatory framework reward[s] networks for improving productivity and service performance

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[62] IEEFA. Appliance standards are key to driving the transition to efficient electric homes. 23 April 2024. Note: An increase in minimum energy performance standards for household appliances with electrification could result in a 153% net decrease in demand across the NEM.
[63] CSIRO. Consumer impacts of the energy transition: modelling report. July 2023. Page 26. Note: Up $500 of benefits are available to all consumers arising from electric vehicle (EV) uptake by 2050.
[64] IEEFA. Saturation DER modelling shows distributed energy and storage could lower costs for all consumers if we get the regulation right. 27 April 2023.
[65] IEEFA. Power prices can be fairer and more affordable. 22 November 2023.
[66] AER. AER Statement – Institute for Energy Economics and Financial Analysis report on electricity network profits. 22 November 2023.

beyond benchmarks", and as such is due to 'outperformance', rather than supernormal profits. However, the appendix to this report details the vexed issue of productivity and shows that even by the AER's own measure, productivity has declined since 2006 and so cannot explain supernormal profits.

This issue concerns the implementation of the existing regulation, rather than the logic and rationale behind the building block regulation. Nevertheless, it presents a red flag that the system is not currently working in consumers' interests. Preventing future supernormal profits should be a goal of any regulatory reform.

Whatever new form of regulation is established, there should be, as Orme suggests, monitoring of the AER's performance. He recommends that the Commonwealth develops and applies an "outcomes performance evaluation framework for monopoly network regulation by the AER".

In 2020, the Australian National Audit Office (ANAO) reviewed whether the AER is effectively regulating the NEM and found: "The Australian Energy Regulator has been a partially effective regulator of energy markets."[67] The ANAO also stated: "Performance reporting arrangements have not enabled the AER to demonstrate it is meeting its purposes, such as promoting the efficient operation of energy services for the long-term interests of energy consumers with respect to price, quality, reliability and security."

> **The AER's performance in economic regulation has never been independently examined.**

Given that the ANAO did not examine the AER's implementation of network revenue regulation, as far as we are aware, the AER's performance in economic regulation has never been independently examined.

9. Network economic regulation has not been amended following the addition of emissions reductions to the NEO

As of 21 September 2023, an emissions reduction objective has been included in the National Electricity Objective (NEO) of the National Electricity Law (NEL): "the achievement of targets set by a participating jurisdiction – for reducing Australia's greenhouse gas emissions; or that are likely to contribute to reducing Australia's greenhouse gas emissions."[68]

While the AEMC and AER have issued guidance on the amended National Energy Objective, they have not considered changing the economic regulation of electricity networks as a result.[69,70] The

[67] Australian National Audit Office. Regulation of the National Energy Market. 3 September 2020.
[68] Government of South Australia. National Electricity (South Australia) Act 1996.
[69] AEMC. How the national energy objectives shape our decisions, Final guidelines. 28 March 2024.
[70] AER. AER - Guidance on amended National Energy Objectives - Final guidance note. September 2023.

AER has stated it intends to “apply the interim value of emissions reduction quantitively in our regulatory decisions where, in the AER’s regulatory judgment, it is appropriate to do so”, but this operational decision-making does not preclude the need to consider changes to the economic regulation itself.[71]

IEEFA suggests that, given there is a legislated national emissions target of 42% by 2030 and a national policy of 82% renewables by 2030 as core to achieving that target, the economic regulation needs to be reviewed to ensure it supports meeting these targets.

While reviewing for emissions reduction, it would also be appropriate to assess the ability of the economic regulation to support appropriate resilience expenditure by networks. This is for two reasons. First, networks are already planning their own ad-hoc resilience expenditure and this is a potential over-investment risk. Second, it is very important that resilience is appropriately addressed in network planning and investment given the pace of climate change. The AER has issued a guidance note on resilience, but as it says, resilience is absent from the National Electricity Rules (NER).[72]

10. Lack of regulatory support for innovation

In 2017, KPMG was commissioned by energy officials to examine “what regulatory framework will best deliver efficient and innovative electricity network and non-network solutions at an efficient price in the context of an evolving energy system?” KPMG’s resulting report expressed concern about many factors that could inhibit innovation and transformation, including:

- The fact that the current framework has been designed for a steady state, compared with the current uncertain and dynamic rate of change.
- The long (five-year) regulatory period.
- The staggered timing of regulatory reviews.
- The propose-respond model and its limitations on the regulator’s role.
- The lack of flexibility of the regulatory framework.
- The lack of incentive to innovate.

KPMG highlighted that “The changes that are expected to the way in which Network Service Providers (NSPs) operate requires a fundamental industry transformation”, and observed there were several common characteristics to an effective approach to encouraging flexibility and innovation in network and non-network solutions:

[71] AER. AER - Guidance on amended National Energy Objectives - Final guidance note. September 2023. Page 9.
[72] AER. Network resilience – A note on key issues. April 2022.

1. A range of approaches are required – incentive schemes alone cannot address the innovation challenge.
2. A clear vision of the role of network service providers in the new energy system.
3. Additional, temporary incentives may be necessary to facilitate transformation.
4. Incentives should be straightforward – not too complicated or administratively burdensome.
5. Consumers should have an increased say.
6. Greater flexibility is likely to be required for both the regulator and the business given the pace of change.

While the ACCC was less focused on innovation in its 2018 review, it was concerned that demand management has been underutilised by distribution networks in meeting the roughly 40 hours of peak demand per year.[73] It made clear that distributed resources could assist in reducing the costs of peak demand and recommended "The AER, in undertaking the revenue determination process, should include a more explicit focus on assessing the efficient use of non-network expenditure."[74]

This situation has not improved. Under the revised Demand Management Incentive Scheme (DMIS), there was only AU$3.2 million in expenditure out of about $1 billion available in the 2017-2022 network revenue period.[75] The DMIS is capped at 1% of distribution network allowable revenue.

An alternative view is that economic regulation has no capacity to deal with innovation. In correspondence with IEEFA, Professor Ron Ben-David wrote: "Economic regulation was designed for industries (i.e. utility service providers) that are in steady state – where change is, for the most part, incremental, predictable and estimable. Economic regulation was never designed to deal with industries in flux – that is, industries requiring substantial R&D [research & development], innovation, speculative investment, and the mass stranding of sunk assets."

Seven years have passed since the KPMG review, and there are three major outstanding questions: to what extent, if any, could economic regulation assist DNSPs to innovate? How could economic regulation assist Australia to meet its decarbonisation objectives? And how – through economic regulation or independently – can innovation funding be provided for DNSPs and to what level is it needed?

The Australian Renewable Energy Agency (ARENA) has played a significant role to date in funding DER integration projects, including trials of DER providing Reliability and Emergency Reserve Trader (RERT) supply, and trials of DER providing network services in Projects Networks Renewed, Consort,

[73] ACCC. Retail Electricity Pricing Inquiry—Final Report. June 2018. Page 173.
[74] Ibid. Page xx.
[75] AER. Decision Demand Management Incentive Scheme (DMIS) payments for 2020–21 and 2021–22. 19 May 2023.

Edge and Symphony. It would be useful to benchmark this funding and its outcomes with the network innovation funding provided by the British Government. This includes the Strategic Innovation Fund (SIF), a five-year programme introduced in 2021 to assist decarbonisation across the gas and electricity networks, in line with the government's net zero objectives.[76]

Other than through the provision of funding, can DNSPs be encouraged to innovate? IEEFA discussions with current and former staff at DNSPs suggest they face significant internal challenges to innovation. IEEFA recommends the Productivity Commission turn its collective intelligence towards this challenge. How can there be an incentive and competitive pressure on DNSPs to implement and exploit innovation?

Part C. Other challenges with the existing economic regulation

11. The ongoing lack of cost-reflective network pricing

Economic regulation does not just set what the total revenue for a firm should be, but usually determines how prices should be set for customers in the interests of efficiency and equity. When DNSPs submit their revenue proposals to the AER, they are required to submit a tariff structure statement (TSS), which sets out how they will progress network tariff reform. The AER must review this statement and check it against the requirements for network tariffs under the National Energy Rules (NER). Prices are then refined annually via a pricing proposal following a compliance check by the AER.

While the interest of this report is primarily in the total cost of electricity distribution network services to Australian consumers and the Australian economy, the issue of how prices are determined is germane to decarbonisation and the effective integration of DER, and hence should be in scope for any review. The lack of cost-reflective network tariffs is currently a major barrier to the efficient investment and use of DER.

The economic ideal is 'cost-reflective pricing' whereby consumers pay or are paid for their impact on or contribution to distribution network operation to minimise cross-subsidies. For example, the AEMC modelled the impact of an air conditioner installed in 2014 on distribution networks to be $1,000, but the additional price paid to the networks by the household with the air conditioner as only $300/year.[77] Given the rapid uptake of DER, which changes the use of distribution networks and creates the potential for owners of DER to be paid to provide network services, the issue of cost-reflective pricing is becoming more urgent.

[76] UK Research and Innovation. Funding announced for 53 new electricity and gas network projects. 4 April 2023.
[77] AEMC. Rule Determination: National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014. 27 November 2014. Page vi.

The 2018 ACCC review recommended "Governments should agree to mandatory assignment of cost reflective network pricing on retailers, ending existing opt-in and opt-out arrangements."[78] DNSPs can currently trial innovative tariff structures, and the proportion of customers on cost-reflective network tariffs is increasing (it is currently more than 40% of customers in the ACT and AusNet's network), but there is no requirement for retailers to pass through cost-reflective network tariffs to customers.[79] In addition, there is the issue that in some cases network demand charges do not reflect the capacity available in the network.[80]

While the focus of this report is the need to change the network revenue regulation, consideration should be given to how time- and location-based network pricing could support overall economic efficiency and the use of DER to provide network services at lower cost than network replacement or augmentation.

Locational marginal prices are designed to reflect the marginal cost of meeting an additional unit of demand, taking into account the physical limits of the network and Kirchoff's circuit laws dictating the flows of electricity. Locational marginal pricing supports efficient behaviours by, and investments in, DER by providing all users including DER with signals that reflect the needs of the real-world system (rather than a notional system without bottlenecks as with a single national wholesale price). However, such pricing is only currently used in transmission systems in some US states and in Germany and Great Britain. The Regulatory Assistance Project (RAP) is not aware of any jurisdictions that use locational marginal pricing at the distribution level.[81]

The Essential Services Commission (ESC) in Victoria was asked to examine if Victoria's existing minimum feed-in tariff reflected the 'true value' of distributed generation, understood as the direct temporal and locational value of distributed generation in the wholesale electricity market, as well as the value of its indirect contributions to environmental and social outcomes. The ESC proposed that Victoria introduce location-based pricing in 2019 in the form of two regions reflecting differences in average line losses across the state (Melbourne, Geelong and the east of the state; and the north and west of the state); however this has not occurred.[82]

There have been a number of trials of DER providing network services in Australia. Project Edith is particularly germane here because it tested real-time network pricing for customers who already have a retailer or aggregator managing their battery in a VPP. The ultimate aim is a price structure that changes as needed on a five-minute basis to manage network hosting capacity in combination with dynamic operating envelopes (DOEs, or flexible exports).[83]

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[78] ACCC. Retail Electricity Pricing Inquiry—Final Report. June 2018. Page xix.
[79] AER. State of the Energy Market 2023. October 2023.
[80] Marsden Jacobs Associates. Review of Ausgrid's Revised Network Tariff Proposals and the Australian Energy Regulator's Draft NSW DNSPs' Tariff Determinations: Are They Reasonable? Report for Evie Networks. 2 February 2024..
[81] Energy Systems Catapult. Assessment of locational wholesale electricity market design options in GB. 2023.
[82] Essential Services Commission. The Energy Value of Distributed Generation, Distributed Generation Inquiry Stage 1 Final Report. August 2016.
[83] Ausgrid. Project Edith. 2023.

The Energy Security Board summarises the 'emerging challenges' of network pricing as follows: "Dynamic pricing introduces additional layers of sophistication, utilizing real-time data and technology-enabled automation. This has shown promise in incentivizing behaviours that align with real-world network conditions, thereby making better use of available network capacity. However, the challenge lies in balancing the complexity introduced by dynamic pricing against the need for easy customer comprehension. Existing structures like NEM's five-minute increments offer a foundational understanding, but adapting these for DSO-specific, location-based conditions remains a lesson in progress."[84]

Questions of tariff design tend to receive disproportionate attention from regulators and the industry. The major focus of any review should be how the overall size of the revenue pie that the tariffs slice and dice is decided. However, tariff design should also be considered, particularly in terms of how it could best support DER provision of network services. For example, Ausgrid staff have indicated to IEEFA that, on the basis of its experience with Project Edith, this may involve a transition from tariffs based on long-run marginal cost to short-run marginal cost. It may well be that Australia does not need to develop markets for flexibility services in the way Great Britain has, but that well-designed tariffs can fairly reward DER for providing network services.

12. Reputational and bespoke incentives for DER exports are insufficient to address the DER integration challenges

Further to the question of contestability and the critique of incentives for innovation is the history of the AEMC and AER's approach to DER integration. After the AEMC decided in 2021 that DNSPs could impose charges on consumers for exporting to the grid, the AER consulted in 2023 on incentivising and measuring export services performance.[85] It decided that the incentives under the existing regulatory regime do not need to change to support DER integration. Instead, the AER decided to introduce 'reputational incentives' via annual export service performance reporting and a new 'small-scale' Export Service Incentive Scheme (ESIS) whereby DNSPs can propose bespoke incentives to improve export service quality.

The AER has stated: "We expect that the ESIS will be a transitional measure until it is possible to introduce a standardised scheme for all DNSPs via the STPIS."[86]

These tweaks around the edges suggest the AEMC and AER have not addressed the fundamental changes that DER is creating in distribution networks. To give one data point, under AEMO's draft 2024 Integrated System Plan, 74% of storage capacity in the NEM is expected to be behind-the-

[84] Energy Security Board. Consumer energy resources and the transformation of the NEM - Critical priorities to support transformation: a call to action. 12 February 2024.
[85] AER. AER - Final - Export Service Incentive Scheme. June 2023.
[86] AER. Incentivising and measuring export service performance. March 2023. Page 18.

meter. This is estimated to be 45GW of storage that will be exporting into distribution networks by 2050.[87]

13. The previous difference in RABs and revenues between government-owned and privatised distributors

In his PhD research, Professor Bruce Mountain of Victoria University uncovered discrepancies of 46% and 26% respectively between the RABs and revenues of government-owned DNSPs compared with privately-owned distributors over 2006-2013.[88] The economic regulation assumes that financing costs are invariant to ownership, but government-owned businesses can, of course, borrow at lower costs than private firms.

Mountain suggests that "compensating government distributors' financing costs at a rate substantially above their actual financing costs, encouraged inefficient expansion of the regulated asset base to deliver higher profits. Consistent with this, the evidence also suggests that extraordinary profits encouraged government owners to attempt to limit the extent of regulatory power in order to protect those profits."[89]

The view of the ACCC review was that excessive network reliability standards imposed in Queensland and NSW drove RAB growth, alongside "a regulatory regime tilted in favour of network owners at the expense of electricity users".[90] While the 'Better Regulation' reforms of 2012-14 appear to have significantly addressed these issues, in any revision of the economic regulation, efforts should be made to ensure the outcomes are invariant to ownership.[91]

14. The practical and operational burden of regulation

The revenue determination process under the propose-respond model takes more than three years: at least two years for the DNSP to prepare its proposal; and about 18 months for the AER to prepare its draft and final determinations. It is complicated and expensive. The Productivity Commission explained this in detail:

"The theory is simple. Its practical realisation is not. The regulatory arrangements underpinning incentive regulation are protracted and costly. The Rules that stipulate many of the requirements for proposals are lengthy and subject to regular changes — currently around 1500 pages, and by early 2013 up to the 55th version in just seven years. (The sections of the Rules most relevant to this inquiry are around 200 pages in length.) Proposals and the regulator's determinations have also become increasingly detailed over time. The decision documents for Victorian electricity distributors

[87] AEMO. 2023-24 Inputs, Assumptions and Scenarios data.
[88] Bruce Mountain. Ownership-invariant Regulation of Electricity Distributors in Australia: A Failed Experiment. January 2017. Thesis submitted in fulfilment of the degree of Doctor of Philosophy. Victoria University.
[89] Utilities Policy. Ownership, regulation, and financial disparity: The case of electricity distribution in Australia. October 2019.
[90] ACCC. Retail Electricity Pricing Inquiry—Final Report. June 2018. Page ix.
[91] AER. Overview of the Better Regulation reform package. April 2014.

were around 450 pages in 2000, around 1000 pages in 2005 and 1800 pages in 2010 — reflecting the complexity of the proposals and the large network revenues involved (now around $13 billion annually in 2011 prices across the NEM). The AER has felt obliged by the Rules to engage in the detailed consideration of business's proposals in reaching final revenue determinations. For example, there have been debates about the efficient number of locks and keys, the length of insulated conductors and appropriate pole treatment processes. In this context, it is not surprising that the approximate administrative costs for the regulator and the businesses of the last complete cycle of revenue determinations were around $330 million (which excludes merits review costs)."[92]

A current example is the SA Power Networks revenue determination, which was initiated on 31 October 2022. On 3 July 2023, the AER published the final Framework and Approach for SA Power Networks; SA Power Networks lodged its proposal on 31 January 2024; and the AER expects to complete its draft determination in 2024, with its final determination to follow in early 2025.[93] SA Power Networks's *Attachment 20 - List of Proposal* documentation lists 130 documents in an Excel spreadsheet. Everything is documented, from a Public Lighting Pricing Model, to 'Adelaide flying-fox population trend', to the 'Mt Barker Depot' – which has its own capex business case.[94]

The thousands of pages in each determination would appear to address the information asymmetry between the proponent and the regulator, but threaten to swamp the regulator in detail. The inefficiency of this process begs the question: is there not a better, more efficient way?

A further question is, what is the appropriate timeframe for setting network revenue given the fast pace of the energy transition? Great Britain has reduced the length of its regulatory period from eight to five years. It is likely than even shorter periods are appropriate given that the longer the regulatory period, the higher the uncertainty about future states. IEEFA suggests simplified, bi-annual network revenue regulation as an option to be considered in a review.

Part D. International trends and case studies in economic regulation

This section presents case studies from the US and Europe that shed light on reform efforts to make better use of network services/non-wires alternatives/flexibility services which can be provided by DER. It focuses on reforms that have sought to overcome traditional capex biases inherent in network regulation through a shift to totex, flexibility procurement and reforms to introduce performance incentives that unlock the potential of DER.

[92] Productivity Commission. Electricity Network Regulatory Frameworks. Report No. 62. 9 April 2013. Page 27.
[93] AER. SA Power Networks - Determination 2025–30.
[94] AER. SAPN - Attachment 20 - List of Proposal documentation - January 2024. January 2024.

15. Totex regulation

In 2013, Ofgem introduced the new RIIO (Revenue = Incentives + Innovation + Outputs) revenue regulation for electricity distribution network, which is a totex-based approach where capex and opex expenditures are treated holistically.[95,96] The purpose was to address concerns that the previously economic regulation might stimulate distribution network business's preferences towards capital-intensive investment.[97] The totex approach pioneered in Great Britain has been cited by stakeholders as an important enabler of local flexibility markets, spurring growth in capacity of local flexibility trading.[98,99,100]

The totex approach is based on the total cost the company expects to incur when it employs what is judged to be an efficient mix of capital and non-capital (operating) inputs. A fixed proportion of a company's totex is added to the RAB, irrespective of whether it comprises capex or opex. Thus, baseline totex is set taking a view on the justification for the investment and making an allowance for efficient costs. Network operators are incentivised to beat these allowed costs through a sharing mechanism that allows them to keep a share of any underspend or bear a proportion of any overspend.[101]

Under the Totex Incentive Mechanism (TIM), any over- or under-spend by DNOs against their totex allowances ('the performance') is shared with customers. The proportion of performance shared with customers (known as the TIM incentive rate) can differ by DNO depending on Ofgem's confidence in independently assessing a DNO's costs. While the proportion of performance that a DNO retains potentially ranges from 50% (where Ofgem has high confidence) down to 15% (where confidence is low), in practice the range in the TIM incentive rate across DNOs in the second RIIO distribution price control period (RIIO-ED2) was from 49.3% to 50%.

Other European countries have followed Great Britain's lead in employing a form of totex approach over the last 15 years. These include Belgium, Italy, Portugal, Lithuania, the Netherlands and

[95] The RIIO regulation comprises a revenue cap plus performance incentives. Performance Incentive Mechanisms (PIMS) are available for six outcomes: safety, environment, customer satisfaction, connections, social obligations and reliability/availability. In addition, RIIO has allocated high levels of innovation funding to approved pilots through a Network Innovation Allowance (NIA) and an annual Electricity Network Innovation Competition (NIC).
[96] Italian Regulatory Authority for Energy, Networks and Environment (ARERA). Overview of RIIO Framework. October 2017. Note suggestions that the totex-based scheme was actually applied in the British energy sector for electricity distribution as early as 2010 under price control DPCR5.
[97] Guarini Center on Environmental, Energy and Land Use Law. Reforming Electricity Regulation in New York State: Lessons from the United Kingdom. January 2015. Note: In previous revenue regulation, Ofgem determined efficient levels of both operating and capital expenditure as separate inputs into the base revenue calculation. Because only capex counted toward the regulated asset base, which generates a return on equity from future ratepayers, it was considered that the old arrangement created an incentive for companies to solve problems with capital expenditures, even when operating expenditure solutions may have been able to deliver the desired level of output at lower life-cycle cost.
[98] Piclo. Three ways RIIO ED2 will impact flexibility markets. 4 April 2023.
[99] Smart Energy Europe. Local Flexibility Markets. June 2022.
[100] Energies. Local Flexibility Markets for Distribution Network Congestion-Management in Center-Western Europe: Which Design for Which Needs? 7 July 2021. Local flexibility markets allow a selection of assets to be activated to settle congestion on the distribution network based on a price signal.
[101] Economic Consulting Associates. An overview of Ofgem's latest electricity distribution price controls (RIIO-ED2). February 2023.

Sweden. While there is not yet an empirical literature showing resulting savings for consumers, this adoption of totex suggests an expectation of a net consumer welfare benefit.

Somewhat surprisingly, totex regulation has not been adopted in any US state. The Rocky Mountain Institute (RMI) attributes this to a perception, but in fact not a reality, that totex could conflict with US accounting standards – potentially making a utility look like a riskier investment and driving up the cost of capital.[102]

16. Flexibility/network services procurement

In Europe, Regulation (EU) 2019/943 "on the internal market for electricity" sets the direction of member states to use DER to provide network services. It demands national regulators offer incentives for "the most cost-efficient operation and development of [distribution] networks including through the procurement of services".[103] This includes for the provision of "congestion management in their areas, in order to improve efficiencies in the operation and development of the distribution system".[104] The network services at a distribution level are usually congestion management, voltage control, reliability enhancement and network deferral.

Distribution networks should be enabled and incentivised to use services from DER, based on market procedures in order to operate their networks efficiently and avoid costly network expansions. The regulation requires that distribution system operators "procure such services in accordance with transparent, non-discriminatory and market-based procedures" (with possible exemptions if deemed appropriate by the regulator).[105]

In the EU therefore, distribution networks are now required to procure flexibility services; distribution networks are no longer monopoly providers of distribution network services. Flexibility procurement has so far been developed in six European states (see Table 2).

[102] Rocky Mountain Institute. Making the Clean Energy Transition Affordable: How Totex Ratemaking Could Address Utility Capex Bias in the United States. 2022.
[103] European Parliament. Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast). 5 June 2019.
[104] European Parliament. Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU (recast). 5 June 2019.
[105] Ibid.

Table 2: European distribution system operators' revenue models

Elements for calculation of model	France	Germany	Netherlands	Norway	Sweden	United Kingdom
Regulatory mechanism	Incentive regulation (revenue cap)	Incentive regulation (revenue cap)	Incentive regulation (price cap)	Incentive regulation (revenue cap)	Incentive regulation (revenue cap)	Incentive regulation (revenue cap)
Cost examination	TOTEX (*)	TOTEX	TOTEX	TOTEX	TOTEX	TOTEX
Regulatory period	4 years (2021–2025)	5 years (2019–2023)	3–5 years (2022–2026)	3–5 years (2018–2022)	4 years (2020–2023)	8 years (2015–2023)
Efficiency benchmarking	No	Yes (yardstick)	Yes (yardstick)	Yes (yardstick)	Yes (yardstick)	Yes (yardstick)
Quality incentive	Yes	Yes	Yes	Yes	Yes	Yes
Innovation incentives	— Through tariffs (R & D OPEX not subject to efficiency requirements) — Regulatory sandboxes	— Efficiency bonus passed through tariffs — Regulatory sandboxes	Indirect (**)	Pass-through costs (***)	— Indirect (**) — Pilot regulation on different tariff structures	— Innovation stimulus and price control package (RIIO (****) model) — Flexibility innovation programme

(*) For non-network expenditures.
(**) Innovation as a means to reach other goals.
(***) Under certain conditions.
(****) Revenues = innovation + incentives + outputs.

Source: European Commission.[106]

A 2022 review of European flexibility markets by the Joint Research Centre (JRC), the European Commission's science and knowledge service, concludes that the regulatory framework for distribution businesses revenues and the national context both play significant roles in the level of flexibility procurement and in preferred methods.[107]

In terms of the economic regulation in the European countries with flexibility procurement, all have totex regulation, removing any possibility of capex bias.

Arrangements for innovation funding vary. For example, in France each distribution network proposes an annual R&D budget, which is subject to approval by the regulator. In Germany, while most research and development (R&D) is via large federal government funding programmes, there is a regulatory incentive mechanism that allows networks to partially recover R&D project expenses undertaken annually up to 50% of the total costs not covered by public funding. In Great Britain, there are three innovation measures: the network innovation allowance (NIA), network innovation

[106] European Commission. Local Electricity Flexibility Markets in Europe. 2022.
[107] Ibid.

competition (NIC) and the innovation roll-out mechanism (IRM) – an allowance of 0.5%-1% of base revenues.

The JRC discusses the three ways in which flexibility is procured in these countries:

- Through static or dynamic network tariffs.
- Market-based procurement.
- A rule-based approach, which has been adopted in Germany.

The JRC identifies three leading nations – Great Britain, the Netherlands and France – which take a business-as-usual approach to market-based procurement.

Great Britain is characterised as systematically procuring market-based flexibility and in growing volumes each year. By 2022, all six distribution network operators (that operate within 14 defined licence areas across Great Britain) were identified as procuring flexibility and commercial offers available in the market, and by August 2023, 2.4GW had already been contracted for the 2023-24 year (see Figure 10 below). Electricity distribution companies estimate savings achieved through the use of non-wire solutions usually contracted via flexibility markets to be in tens of millions of pounds per annum.[108,109]

For example, UK Power Networks estimates GBP60m worth of savings were achieved in 2023 by utilising flexibility as an alternative to the traditional approach of delivering network capacity by building more infrastructure.[110] Unfortunately, there is no publicly available economic analysis of the benefits of these flexibility services across the nation. However, in **2016 research by Imperial College and the Carbon Trust estimated that flexibility markets could save Great Britain's grid up to GBP40bn by 2050** compared with a system that adds no flexibility beyond the existing interconnectors and pumped hydro storage.[111]

About 20% of Great Britain networks are constrained, and local network flexibility is procured individually by each of the six distribution networks, earning DER owners up to GBP33/kW/year in some locations. For example, a 10kW home battery can early up to GBP331/year.[112] According to flexibility software platform provider Axle, "smaller flexible distributed assets like EV charging, batteries, and electric heating are best suited to participate. EV charging constitutes the bulk of existing DNO [Distribution Network Operator] flex supply".[113]

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108 For example, see: EPEX SPOT. New partnership between UK Power Networks and EPEX SPOT set to "supercharge flexibility market". 11 January 2024.
109 Current±. Flexible generation saving UKPN customers millions as DSO transition takes hold. 15 November 2017. Note: UK Power Networks estimates its customers have benefitted from around GBP70 million worth of savings 2015-2017 through the use of flexible, distributed generation.
110 EPEX SPOT. New partnership between UK Power Networks and EPEX SPOT set to "supercharge flexibility market". 11 January 2024.
111 Imperial College and the Carbon Trust. An analysis of electricity system flexibility for Great Britain. November 2016
112 Axle. Local Network (DNO) Flexibility: Everything You Need to Know. 4 October 2023.
113 Ibid.

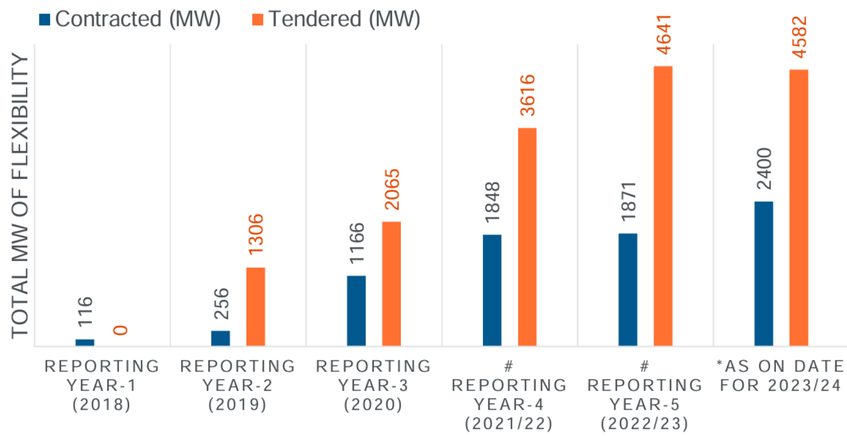
Figure 10: Indicative DER annual revenue in Great Britain in constrained locations

Asset	Rated Power	Flexible Power	Annual Revenue @ £33/kW/yr
EV charging	7	2.2	£73
Home battery	5	5	£166
Home battery	10	10	£331
Electric heating	3	2	£66

Note that DNO flex revenue varies substantially location to location, and is only available in the ~20% of country with an active constraint.

Source: Axle.

Figure 11: Flexibility services in Great Britain (actuals)



* Contracted/Tendered to date, more expected over the remainder of 2023
\# Reporting cycle moved from calendar year to regulatory year

Source: ENA UK.[114]
Note: Tendered and contracted services for delivery in the reporting year.

[114] ENA UK. ON Insights Forum Slides (28 Sep 2023). September 2023. Note: Confusingly in Great Britain, flexibility services also refer to those purchased by the grid operator, National Grid, to balance national demand and generation across the electricity system in real-time.

Flexibility services in Great Britain

In Great Britain, flexibility services are procured from owners, operators or aggregators of DER in the distribution grid, which can consist of generators, storage or demand assets (including some diesel generators), see following Figure. Flexibility services in the distribution networks are of five types:

Sustain – To change exports or imports at specified times for scheduled constraint management (used to manage peak demand loading on the network and pre-emptively reduce network loading).

Secure – To change exports or imports at specified times for pre-fault constraint management (used to manage peak demand loading on the network and pre-emptively reduce network loading).

Dynamic – To change exports or imports at specified times for post-fault constraint management (to reduce the risk of capacity constraints in N-2 fault conditions or during planned works).

Restore – Real-time response to an instruction to either remain off supply, reconnect with lower demand, or to reconnect generation to support faster restoration following an unplanned outage.

Reactive Power – Although no distribution businesses are currently tendering for this.

Source: ENA UK.[115,116]

The Dutch mechanisms are found to be well established, with 136 megawatt-hours (MWh) of flexibility identified as procured by distribution network operator Liander and Enexis in 2021, though this appears to have fallen significantly since.[117,118]

While ENEDIS, the main French distribution network, tendered for 19 opportunities for flexibility for the 2020-22 year, it attracted few bids, and no offers were accepted. The JRC attributes this result to there being more attractive business alternatives for flexibility service providers such as participation in the capacity remuneration mechanism, the specific design of the local flexibility tenders, and the price caps imposed by EDENIS.

[115] ENA UK. ENA ON GB Flexibility Figures 2023/2024.
[116] ENA UK. ON Insights Forum Slides (28 Sep 2023). September 2023.
[117] European Commission. Local Electricity Flexibility Markets in Europe. 2022.
[118] GOPACS.

Norway and Sweden show promise in flexibility procurements, having developed pilot projects.

Germany has elected principally for a regulatory approach to solving network congestion, one that places an obligation on generation to offer flexibility to the network operator, to be remunerated at cost, rather than attempting to create a market-based approach.

In the United States, non-wires alternatives (NWA) or non-wires solutions refer to portfolios of DER providing network services, deferring or eliminating investment in traditional and costlier 'poles-and-wires' infrastructure. While the concept has been around for at least a decade, uptake has been relatively slow. There is no available study of DER providing network services across the US, but there is evidence of some existing NWA projects in New York, California, Hawaii and Massachusetts, and of planned moves towards NWA in Illinois. In all these states distribution companies have developed guidelines or processes for considering NWA.

National Grid (which operates in New York City and State, and Massachusetts) installed a 48MWh battery storage facility on Nantucket in 2019 that helped to defer the implementation of an additional undersea sub-transmission cable. The company's New York affiliate (Niagara Mohawk Power Company), in 2022 operationalised an NWA to defer a distribution network investment in Cicero, New York, comprising 15 megawatts (MW) of distributed solar and 40MWh storage.[119]

National Grid states that it "is relatively nascent on in its journey with NWAs" and intends to use its Future Grid Plan to successfully deploy additional projects in prioritised, high-needs areas. It is proposing to establish a US$50 million DER Grid Services Compensation Fund (GSCF) to support delivery of NWA projects out of a total US$2,390m investment planned over its coming five-year regulatory period.[120]

Similarly, Commonwealth Edison Company's Refiled Multi-Year Integrated Grid Plan for Illinois is proposing relatively small initial investments of US$10.7m in battery energy storage systems and US$1.48m in mobile energy storage systems to provide capacity relief and prevent feeders and/or substations from being overloaded due to congestion. Commonwealth Edison states that these programs will "provide a pathway for future capacity deployments where third-party owned NWAs are considered".[121]

Ameren Illinois has deployed a single NWA solution in the form of a 1MW energy storage system (ESS) at Thebes, Illinois and is planning two further projects.[122]

In one of the most innovative NWA projects approved to date, California's Public Utilities Commission approved special funding in 2022 for "four residential and commercial pilot programs to examine the

[119] National Grid. Future Grid Plan: Empowering Massachusetts by Building a Smarter, Stronger, Cleaner and More Equitable Energy Future. September 2023.
[120] Ibid.
[121] Commonwealth Edison. Grid Plan. March 2024.
[122] Ameren Illinois. Multi-Year Integrated Grid Plan (REFILED). 13 March 2024. Page 190.

costs and benefits of using electric vehicle batteries to supply electricity to homes and businesses during blackouts and as suppliers to the grid (bi-directional charging)".[123]

Performance incentives

Performance incentive mechanisms (PIMs) may be used by regulators to ensure that regulatory pressure on networks to lower costs does not lead to deterioration in the quality of outputs and outcomes, including new ones linked to the energy transition.

Part of the RIIO-ED2 (2023-2028) regulatory architecture that has supported flexibility markets in Great Britain since 2023 is a specific Distribution System Operation (DSO) Incentive, with a value of +0.4% / -0.2% of return on retained earnings per year to spur DNOs to more efficiently develop and use their network, taking into account flexible alternatives to network reinforcement.[124]

This builds on Ofgem's assessment of distribution network performance which is informed by a number of metrics including facilitating efficient dispatch of distribution flexibility services, and coordinating and engaging with third-party platform providers.[125] DNO performance will be assessed through a stakeholder satisfaction survey, performance panel assessment and outturn performance metrics.

In the US, adoption of PIMs is generally becoming more common in states that have adopted aggressive decarbonisation and electrification targets. PIMs are in place in New York, Vermont, District of Columbia, Minnesota, Illinois and Hawaii, while states in the process of introducing them include Connecticut, Maryland, North Carolina, Colorado, Nevada and Washington.[126] A review of policy goals enumerated in PBR-enabling legislation since 2018 in US states shows that "energy efficiency, demand-side management, and *DER expansion*" (italics added) is a policy goal in Colorado, Washington, North Carolina and Illinois. The policy goal of 'emissions reductions' features in these states plus Hawaii and Connecticut.

US regulation expert Paul Joskow stated in a recent paper: "I have been able to identify only about a dozen states that operate under or are planning to implement comprehensive PBR plans that reflect similar mechanisms to those adopted by RIIO for distribution in Great Britain."[127]

One of the first movers was the Reforming the Energy Vision process in New York State. RAP analysis shows how the resulting PIMs have played out in New York State across 2018-2020 in Table 3.

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[123] MIT CEEPR. The Expansion of Incentive (Performance Based) Regulation of Electricity Distribution and Transmission in the United States. January 2024. *Paul L Joskow*.
[124] Ofgem. Consultation – Distribution System Operation Incentive Governance Document. 2022.
[125] Piclo. Three ways RIIO ED2 will impact flexibility markets. 4 April 2023.
[126] Rocky Mountain Institute. States Move Quickly to Performance Based Regulation to Achieve Policy Priorities. 31 March 2022.
[127] MIT CEEPR. The Expansion of Incentive (Performance Based) Regulation of Electricity Distribution and Transmission in the United States. January 2024. *Paul L Joskow*.

Table 3: Performance goals met, total incentive achieved and contribution to return on equity (ROE) for PIMs in New York State, 2018-2020

PIM categories	Consolidated Edison			Central Hudson Gas & Electric			National Grid		
	2018	2019	2020	2018	2019	2020	2018	2019	2020
Coincident peak demand savings	100%	100%	100%	0%	0%	0%	100%	100%	45%
DER utilization	100%	100%	0%	0%	100%	100%	4%	0%	0%
Energy-efficiency savings	100%	100%	N/A	100%	100%	100%	39%	100%	100%
Energy intensity of residential customers	100%	0%	N/A	0%	0%	0%	69%	0%	0%
Energy intensity of commercial customers	0%	0%	N/A	0%	0%	100%	100%	33%	100%
Energy intensity of multifamily customers	34%	61%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Beneficial electrification	N/A	N/A	TBD	100%	100%	100%	47%	100%	100%
Customer engagement	N/A	N/A	N/A	0%	0%	0%	N/A	N/A	N/A
Street lighting conversion	N/A	N/A	N/A	N/A	N/A	N/A	0%	65%	22%
Locational system relief value load factor improvement	N/A	N/A	0%	N/A	N/A	N/A	N/A	N/A	N/A
Total incentive Achieved ($M)	$27.2	$36.6	$11.61	$0.7	$1.6	$2.1	$11.3	$12.1	$12.2
Contribution to ROE	N/A	N/A	N/A	1.4%	3.0%	3.9%	6.4%	6.8%	6.9%

Note: Only outcome-based PIMs are reported. "N/A" means "not available," which indicates that the utility did not have a PIM for this category or ROE values were unavailable. "TBD" indicates the result has not yet been reported by the utility for this category of PIM.

Source: RAP.[128]

Joskow suggest that Hawaii "has perhaps the most comprehensive PBR plan in the US".[129] Given this and the state's high level of rooftop solar penetration and commitment to decarbonisation, it is worth looking at the case of Hawaii in detail.

In 2014 the State of Hawaii made a commitment to shift from fossil fuel electricity generation plant to a fully renewable system by 2045.[130,131] By 2019, 28% of electricity was delivered through renewables, supported by a net metering policy.[132]

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128 Regulatory Assistance Project. Improving Utility Performance Incentives in the United States: A Policy, Legal and Financial Framework for Utility Business Model Reform. 26 October 2023.
129 MIT CEEPR. The Expansion of Incentive (Performance Based) Regulation of Electricity Distribution and Transmission in the United States. January 2024. *Paul L Joskow*.
130 Hawai'i State Energy Office. Memorandum of Understanding between the State of Hawaii and the US Department of Energy. 15 September 2014.
131 Hawaii Public Utilities Commission. Staff Proposal for Updated Performance-Based Regulations. 7 February 2019.
132 Hawaiian Electric. Hawaiian Electric renewable energy rises to 28%. 12 February 2020.

Hawaii's Public Utilities Commission (PUC) overhauled the economic regulation in 2019, noting that:

- Traditional regulatory models for electric utilities may exert an "infrastructure bias" towards deployment of capital-intensive solutions.
- There are few financial incentives for the utility to employ cost-savings measures, to reduce electricity sales, to improve energy efficiency, to increase customer choice, to integrate customer-sited generation, or to establish new and innovative services.
- There was a significant need and opportunity for utilities to contain their operations and maintenance expenses, given previously expressed concerns about growth in expenses.133

The PUC staff proposed a suite of performance-based regulations (see Table 4) to address the multiple challenges presented by the energy transition, increasing the number of regulatory outcomes from five – affordability, reliability, cost control, capital formation and customer equity – to twelve. This approach was implemented in 2020.

Table 4: Hawaii PUC's regulatory goals and prioritised outcomes for utility regulation

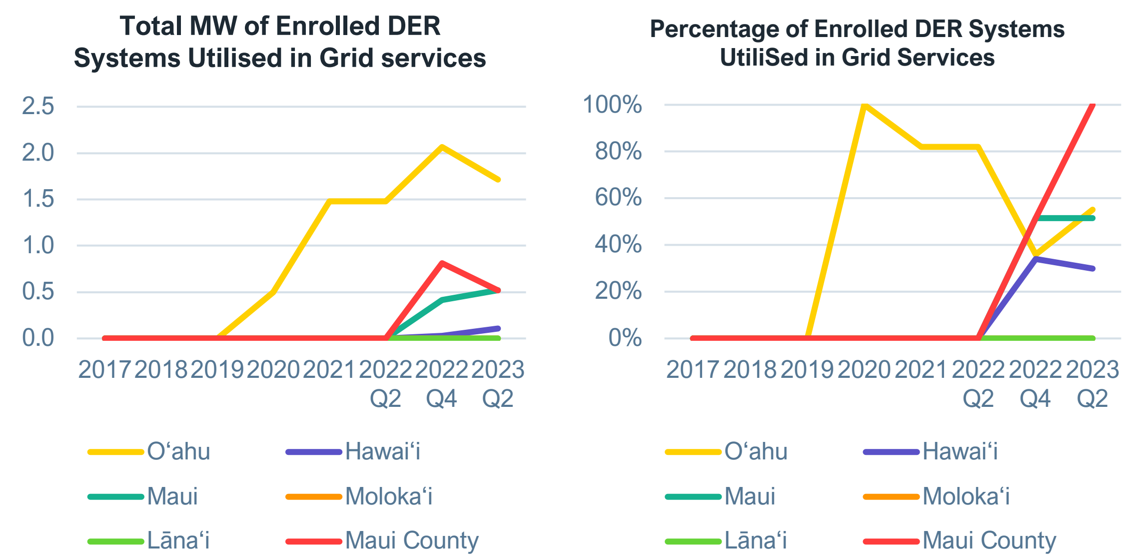
Regulatory Goal	Regulatory Outcome	
Enhance Customer Experience	Traditional	Affordability
		Reliability
	Emergent	Interconnection Experience
		Customer Engagement
Improve Utility Performance	Traditional	Cost Control
	Emergent	DER Asset Effectiveness
		Grid Investment Efficiency
Advance Societal Outcomes	Traditional	Capital Formation
		Customer Equity
	Emergent	GHG Reduction
		Electrification of Transportation
		Resilience

Source: Hawaii PUC.

[133] Hawaii Public Utilities Commission. Staff Proposal for Updated Performance-Based Regulations. 7 February 2019.

- New incentives, targets and metrics were introduced, including metrics that shed light on integration of DER as non-wires alternatives.[134] The DER Grid Services Utilization Reported Metric shows:
- Absolute MW of DER enrolled in grid services that is utilised (see left hand Figure 10).
- Percentage of delivered capability compared to forecast capability (see right hand Figure 10).

Figure 12: Hawaiian Electric – DER Grid Services Utilisation Reported Metric



Source: Hawaiian Electric.

These show growing utilisation of DER for network services, but the scale of the systems is still small in MW terms.[135]

Dr Ron Ben-David identifies PIMs in Australia as "a proliferation of incentive schemes in place for electricity networks [which] comes at a considerable cost to consumers, while the benefits are only ever asserted".[136]

These include the Efficiency Benefit Sharing Scheme (EBSS), Capital Expenditure Sharing Scheme (CESS), Service Target Performance Incentive Scheme (STPIS), the Customer Services Incentive Scheme (CSIS), Demand Management Incentive Scheme (DMIS), Demand Management Innovation Allowance (DMIA) mechanism and the Small-Scale Incentive Scheme (SSIS).

[134] Hawaiian Electric. PBR Scorecards and Metrics - Distributed Energy Resource (DER) Asset Effectiveness.
[135] Ulupono Initiative. Performance-Based Regulation. January 2021. Note: Performance is subject to an incentive with maximum award over a two-year period for all three companies of $1.5 million. The amount of incentive varies depending on the grid service(s) acquired and the service territory served, with rewards varying between $6.40/KW to $39.40/KW.
[136] Monash University. Rethinking markets, regulation and governance for the energy transition. August 2023. *Ben-David, Ron.*

None of these schemes are related to assisting the energy transition, which suggests their role could be reconsidered in a review. For example, PIMs could be considered for rewarding DNSPs for customer service – in areas such as connection times (including for EV charging – by type), imports and exports (for example, through the implementation of dynamic operating envelopes), and lack of outages (albeit possibly with different measurement).

17. International moves from technical to negotiated economic regulation processes

Professor Stephen Littlechild, the originator of the RPI-$\mathcal{X}$ revenue regulation, has been saying for 15 years that it is time to review the approach to economic regulation in electricity, especially given the uptake of renewable energy and smart meters and grids.[137] He states today's challenge is three-fold:

- "To discover what outputs, investments, prices & incentives make most sense in a world that is partly unknown & constantly changing (not least re Net Zero)
- "Also what form & duration of price control(s), & procedures for monitoring & revising
- "In a way that carries companies, customers & other interested parties with it."[138]

He goes as far as to suggest the probable need for "new types of price control to reassure against excess profits; Perhaps shorter-term, perhaps sliding scale, perhaps with reopeners … Probably more like commercial contractual arrangements".

This new view that regulators in practice are administering a long-term contract between consumers and networks is attributed to Dr Christopher Decker at the University of Oxford. RIIO goes some way towards this approach, but it is a perspective worth considering in the Australian context.

The question of consumer involvement in revenue setting processes is a complex one, especially due to the information asymmetry. In Australia consumer advocates have significantly less resources and information than the DNSPs whose decisions they seek to scrutinise. In the US, rate cases are conducted through courtroom-like procedures, and consumer advocates usually engage lawyers to assist.[139]

[137] ACCC. ACCC/AER Regulatory Conference 2009. 30 July 2009. *"Are there substitutes for traditional economic regulation of monopoly infrastructure?" Presentation by Littlechild, S.*
[138] Energy Policy Research Group. Incentive- based regulation: An historical perspective and a suggestion for the future. 5 November 2021. *Presentation by Littlechild, S*
[139] Regulatory Assistance Project. Electricity Regulation in the US: A Guide. Second Edition. 12 July 2016. *Lazar, J.*

18. Observations from the case studies

From these international case studies, we can observe:

- There is growing attention in Europe around how to address capex bias and unlock non-wires alternatives, with totex commonly used.
- Flexibility services or non-wires alternatives provided by DER are most advanced in Great Britain, with initial projects being undertaken at a small-scale in some other Europe countries (especially France, Netherlands, Germany, Norway and Sweden) and some US states (especially New York, California, Hawaii and Massachusetts).
- Further afield in Europe, market-based procurement of flexibility services by distribution networks is still considered a "niche practice in most countries".[140]
- There appears to be a growing momentum towards implementation of performance incentives, with Hawaii among a handful of states leading the way in the US, and Great Britain leading the way in Europe, but with the possibility that European directives will drive momentum across the rest of Europe once fully implemented.
- While only Great Britain has both made significant changes to the economic regulation of networks and seen substantial procurement of network services from DER, there is international momentum towards distribution networks playing a greater role in decarbonisation through supporting the uptake of DER and the use of DER to provide network services.

Part E. Where to from here for the economic regulation of distribution networks in Australia?

19. Existing economic regulation raises many questions that require independent examination

In summary, the existing economic regulation of distribution networks has a range of issues, including:

1. The question about whether or to what extent distribution networks are contestable.
2. The capex bias.
3. The risk of over-investment.
4. The supernormal profits.

[140] European Commission. Local Electricity Flexibility Markets in Europe. 2022.

5. The lack of revision to take into account emissions reduction and resilience.
6. The lack of support for innovation.
7. The lack of cost-reflective pricing.
8. The fact there are only reputational and bespoke incentives for DER exports.
9. The historic differential growth of RABs and revenue across publicly and privately-owned DNSPs.
10. The burden of the propose-respond process.

This list is not exhaustive. This report does not look at the lack of real financial penalties for networks from delays to new project delivery. The aim is to explore the most significant issues in the economic regulation of distribution networks in the transition to a high-DER, high-renewables, highly electrified grid. Then there is the lack of direction-setting reform compared with international jurisdictions.

These issues are so significant that is it is clear the existing economic regulation – based on the building block model – and the propose-respond process are no longer fit-for-purpose amid the fast-moving energy transition, where speed to electrification and decarbonisation are vital to meet the federal government's legislated emissions reduction targets and lower consumer bills. Multiple studies have found there are significant consumer bill savings from electrification.[141]

20. Outcomes and questions for consideration in a Productivity Commission review

Given the issues outlined above, the costs to consumers' electricity bills of distribution networks, and the massive, rapid change in circumstances since the building block regulation was introduced, there is a need for a fundamental, first principles-based review of the economic regulation of distribution networks.

IEEFA's view is that the Productivity Commission is well placed to undertake such a review. We recommend the review look to recommend a form of economic regulation of distribution networks that focuses on achieving the following:

- The best outcomes for consumers in terms of the lowest possible prices.
- Economically efficient outcomes for our economy, including an end to the bias towards capex.
- Fast decarbonisation, including electrification, to achieve Australia's legislated emissions reduction goal which is now part of the NEO under the NEL.

[141] IEEFA. Fast, efficient, flexible electrification can cut energy bills and support the shift to renewables. 6 March 2024.

- Creation of a level-playing field between infrastructure and DER-provided network services.
- Improved climate resilience.

IEEFA recommends the following questions be central to such a review:

1. What is the nature of contestability in distribution network services?
2. Could we make greater use of third parties to provide network services?
3. What outcomes should distribution networks be remunerated to provide?
4. How can and should distribution networks be rewarded for accelerating decarbonisation?
5. How can and should distribution networks be incentivised for innovation (including within and outside economic regulation)?
6. What processes can be used to efficiently determine network revenue, and in what timeframe given the fast-paced nature of the energy transition?
7. How can supernormal profits be avoided?
8. Should performance monitoring of network regulation and the regulator be introduced, and if so, what form should this take?

When IEEFA posed these questions to Rajendra Addepalli of the Regulatory Assistance Project (RAP), he suggested the following analyses will be important:

- What are the drivers of capital and operating investments in the distribution network in the coming decade and beyond? These could include load growth, increased resilience need, replacing aging infrastructure, addressing environmental needs, accommodating increasing DER, smart grid enhancement, and more. A better understanding of the drivers would help formulate solutions that would be pragmatic.
- Consumers will drive the train on adopting and implementing DER. It would be good to understand the expectations of consumers as solutions are fashioned. While the conventional regulatory wisdom is that consumers care about prices and quality of service, today's consumers may value additional attributes such as smart, flexible appliances and software, clean energy and electrification.
- For DER to be used as non-wires alternatives, it takes investment, likely to be from aggregators and retailers. It would be good to know who the likely investors are and what their risk/return expectations are. This could be different from the conventional central generation and wires business investments.

Conclusion

The ENA-CSIRO Electricity Networks Transformation Roadmap identified that “a regulatory regime that is outpaced by technology and market developments cannot protect consumers or deliver a balanced scorecard of societal outcomes.”[142]

It also found there could be AU$16 billion in avoided network infrastructure investment by 2050 through the orchestration of DER to provide network services.[143] In this modelling, distribution networks pay DER customers more than AU$2.5 billion per annum for network services by 2050. The report projected that by 2027, network orchestration using DER on a dynamic locational basis would result in one third of customers selling DER services to networks, directly or through their agents. 2027 is just three years away and we are yet to have the economic regulation that would support the widespread use of DER for network services.

Despite a new maxim developed by regulators about a decade ago of “putting consumers at the centre”, Professor Ron Ben-David has observed that: “So far, the over-riding regulatory response to the energy transition singularly involves continuing the traditions of the past – namely, enabling more choice, more information, more price signals, and more efficient price signals. And just as in the past, the rest is left to consumers to navigate. Nothing has, in fact, changed in substance for consumers.”[144]

He goes on to state (emphasis added): “**An unstoppable force (the energy transition) is on a collision course with a seemingly immovable object (regulatory tradition).** The risk of economic fall-out and a stalled energy transition is significant if the community loses confidence in the energy market and those regulating it.”

Jean-Michel Glachant from the Florence School of Regulation summarises the current situation as follows (emphasis added*):*

“It cannot make sense to remunerate TSOs [transmission network businesses] with a guaranteed return on the amount of steel and concrete put into their balance sheets for much longer, or to back DSOs [distribution network businesses] for the ‘fit-and-forget’ expansion of their network capacity. Furthermore, the network owners and the network users must be brought into interactive loops of key performance indicators, incentives, coordination and commitments, with regard to the way electricity is injected, withdrawn or stored, and the grids planned and used, right up to changing the way all the players (including all grid users, all electricity consumers) invest in their own portfolio of assets, be they connected or off-grid. **New incentive regulation and coordination tools must be invented and inserted into a multi-level operation and investment framework, to allow smarter**

[142] ENA patterned with CSIRO. Electricity Network Transformation Roadmap, Interim Program Report. 20 December 2015. Page 16.
[143] ENA patterned with CSIRO. Electricity Network Transformation Roadmap: Final Report. 17 April 2017.
[144] Monash University. On collision course: Economic regulation and the energy transition. June 2023. *Ben-David, Ron*.

interactions between the grid users and the grid owners, via their new digital interface, or via intermediaries, at all levels – transmission, distribution, behind the meter and off-grid."[145]

Deciding how to remunerate electricity distribution networks, in order to meet 82% renewable generation in the NEM by 2030 and higher percentages beyond then, while ensuring efficient operation and lowest efficient costs for consumers, is a challenge. However, the Productivity Commission is well placed to examine all the issues set out in this paper. Indeed, it has already examined network regulation once before under different circumstances.

IEEFA recommends the Productivity Commission be given this task, which will have significant implications for household and business bills, Australia's economic productivity and our international competitiveness.

Acknowledgements

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[145] Edward Elgar Publishing. New Business Models in the Electricity Sector Handbook on Electricity Markets. 2021. Page 462. *Glachant, Jean-Michel*.

Technical appendix: Measuring DNSP productivity

How the AER measures productivity

Since 2015, the AER has assessed the economic productivity of DNSPs through time series multilateral total factor productivity (MTFP) analysis. This ‘economic benchmarking’ is released annually and compares total inputs (capex and opex) to total outputs. There are five physical measures of capital inputs that DNSPs invest in to replace, upgrade or expand their networks. These are:

1. Overhead distribution (below 33 kilovolts (kV)) lines.
2. Overhead sub-transmission (33kV and above) lines.
3. Underground distribution cables (below 33kV).
4. Underground sub-transmission (33kV and above) cables.
5. Transformers and other capital.

In addition, there is the opex to operate and maintain the network. Transformers and other assets are measured in MVA, while lines and cables are measured in MVAkms.

The outputs the AER measure for DNSPs (and the current relative weighting applied to each) are:

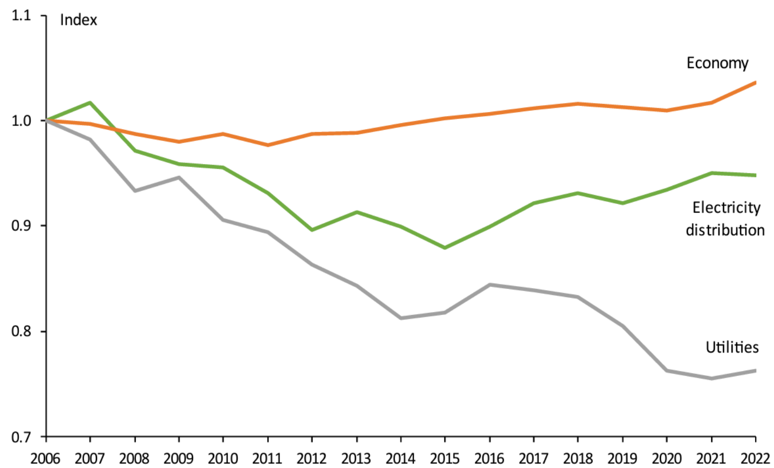
- **Customer numbers.** The number of customers is a driver of the services a DNSP must provide (about 19% weight).
- **Circuit line length.** Line length reflects the distances over which DNSPs deliver electricity to their customers (about 39% weight).
- **Ratcheted maximum demand (RMD).** DNSPs endeavour to meet the demand for energy from their customers when that demand is greatest. RMD recognises the highest maximum demand the DNSP has had to meet up to that point in the time period examined (about 34% weight).
- **Energy delivered (MWh).** Energy throughput is a measure of the amount of electricity that DNSPs deliver to their customers (about 9% weight).
- **Reliability (Customer minutes off-supply).** Reliability measures the extent to which networks can maintain a continuous supply of electricity (customer minutes off-supply enters as a negative output and is weighted by the value of customer reliability).[146]

By the AER’s measure, electricity distribution productivity has exceeded utilities since 2006, but tracks below the productivity of the Australian economy as a whole. All graphs in this section are

[146] AER. Annual Benchmarking Report – Electricity distribution network service providers. November 2023. Page 3.

from the AER's 2023 Annual Benchmarking Report for Distribution Network Service Providers, unless indicated otherwise.

Figure 13: Electricity distribution, utility sector, and economy productivity, 2006-22



Source: AER. [147]

By the AER's measures electricity distribution capital productivity has fallen substantially over the entire period while opex productivity has increased since 2015.

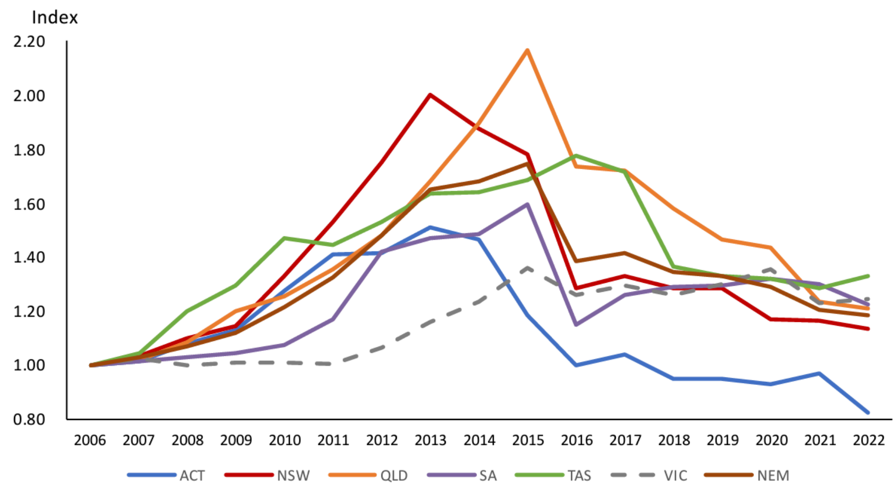
Figure 14: Electricity distribution, total, capital and opex productivity, 2006-22

Source: AER.[148]

[147] AER. Annual Benchmarking Report – Electricity distribution network service providers. November 2023. Page iv.
[148] Ibid. Page 25.

The reasons for the differences in opex and capex productivity relate to the large increase in capital expenditure, which increased the size of the RABs in the NSW and Queensland DNSPs in particular through 2009-2015. The history and reasons for this are well documented in the ACCC's 2018 review of retail electricity.[149]

Figure 15: Indexes of distribution network revenues by jurisdiction, 2006–2022

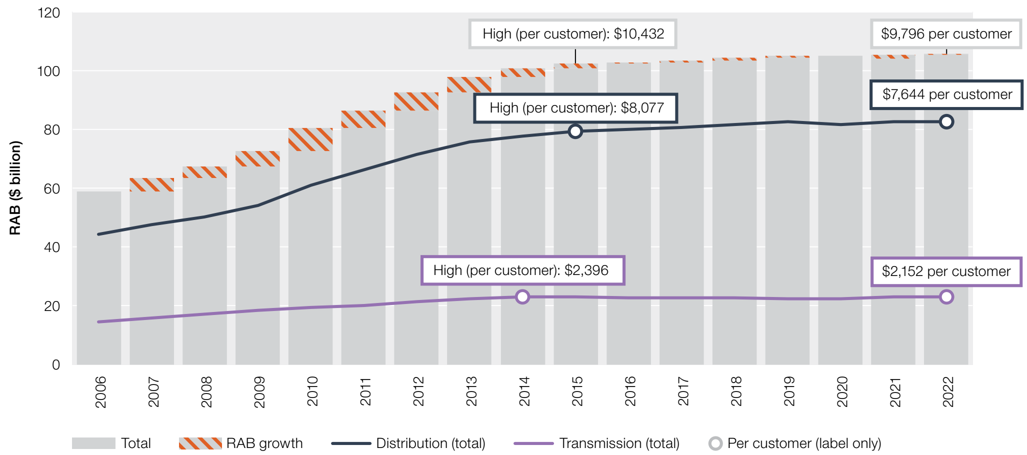


Source: AER.[150]

The RAB per customer for DNSPs peaked in 2015. RAB per customer has stabilised and slightly declined (see Figure D) due to a number of changes – including the abolition of the Limited Merits Review process, changes to reliability standards in NSW and Queensland, reductions in spending on network augmentation and reductions in the WACC – packaged up as Better Regulation distribution.[151]

[149] ACCC. Retail Electricity Pricing Inquiry Final Report. 2018.
[150] AER. Annual Benchmarking Report – Electricity distribution network service providers. November 2023. Page 20.
[151] AER. Overview of the Better Regulation reform package. April 2014.

Figure 16: Value of electricity network service provider assets (RAB)

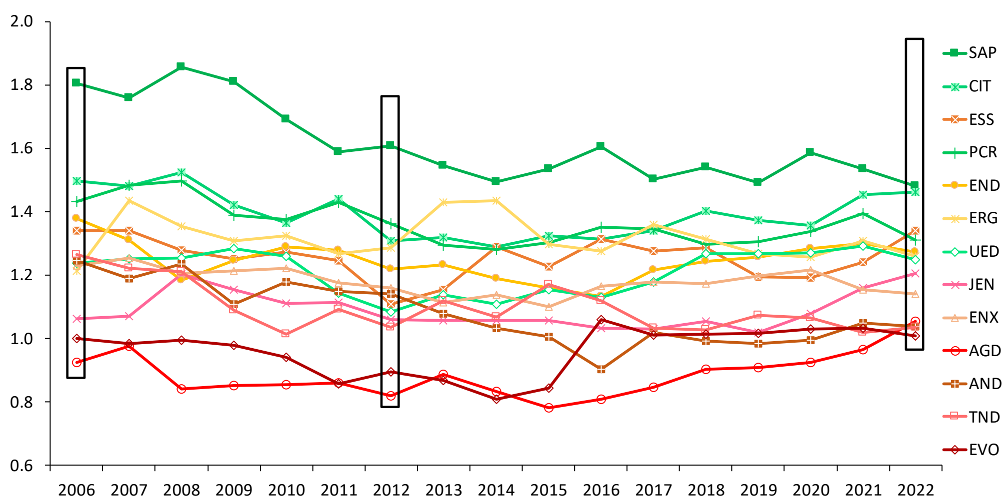


Note: All data are adjusted to June 2022 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER.[152]

By the AER's measures the gap between the best performing (SA Power Networks) and worst performing electricity distribution networks has narrowed since 2006 (see Figure E).

Figure 17: MTFP indexes by individual DNSP under the approach used in previous reports, 2006–2022

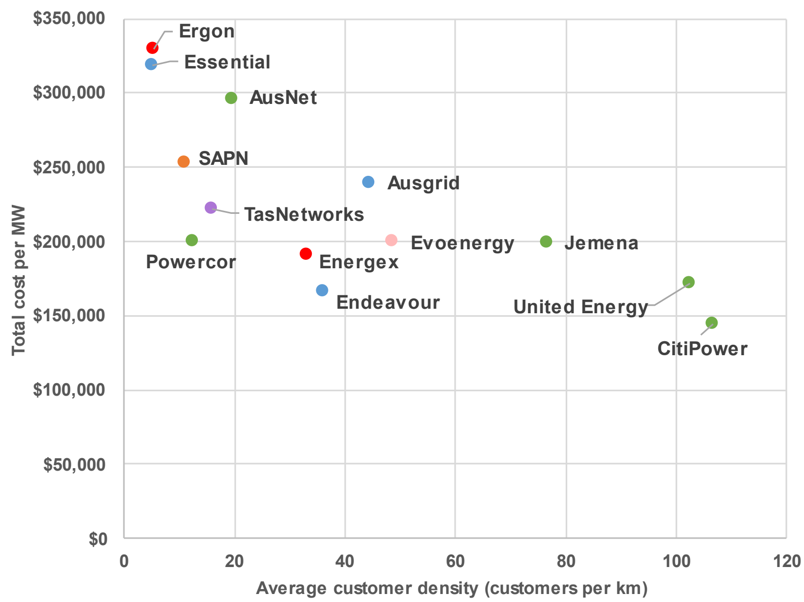


Source: AER.[153]

[152] AER. State of the Energy Market 2023. 5 October 2023. Page 106.
[153] AER. Annual Benchmarking Report – Electricity distribution network service providers. November 2023. Page 33.

However, by the AER's measures the cost per MW of maximum demand over the last five years of electricity distribution networks has varied from between about $150,000/MW to $350,000/MW – with the rural and regional networks generally, but not always, being more expensive (see Figure 10).

Figure 18: Total cost per MW of maximum demand ($2022) (average 2018–2022)



Source: AER.[154]

Issues with how the AER measures productivity in a high DER-world

As we have seen, MTFP analysis is the ratio of aggregate output to aggregate inputs. The AER's measure of MTFP is curious given that productivity should be based on the outputs that consumers value, not what DNSPs value. Consumers value continuous electricity supply, including at times of peak demand, but are generally agnostic as to the source of supply; it is price that is of greater significance – hence the rapid uptake of rooftop solar.

In terms of the relevance of the AER's measures of outputs in a high-DER world:

- **Customer numbers** – are legitimate; the number of connections serviced is still significant.
- **Circuit line length at 39% weight** – It appears to be anachronistic to measure an output when electricity supply is not dependent on line length.
- **Ratcheted maximum demand (RMD) at 34% weight** – appears to reward DNSPs for not taking measures to reduce maximum demand, which should be core to reducing costs.

[154] Ibid. Page 60.

- **Energy delivered (MWh)** – is less a consideration. Both energy delivered and energy exported should be considered in measuring the productivity of DER-rich distribution networks.
- **Reliability (Customer minutes off-supply)** – is also becoming less relevant with the uptake of DER, especially batteries.

Given these concerns with the AER's measure of productivity, we suggest that the current MTFP is ill-suited to rapidly changing distribution networks with high penetrations of DER. It would be worth the Productivity Commission considering how productivity should be measured in high-DER distribution networks as part of its consideration of economic regulation. The graphs in this section give us very little insight into understanding the economic productivity and relative efficiencies of the DNSPs.

About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. www.ieefa.org

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