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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

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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.

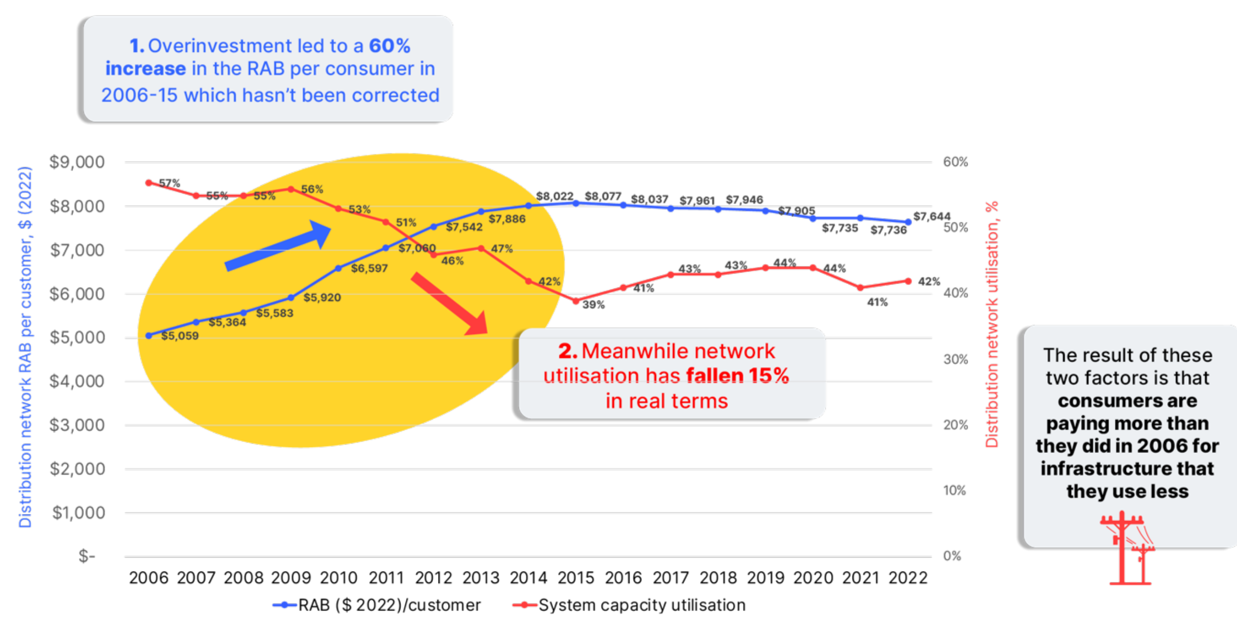
IEEFA recommends the Productivity Commission undertake a first-principles review of the economic regulation of distribution networks, which would identify ways to ensure efficient costs of network services in a high-DER world.

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



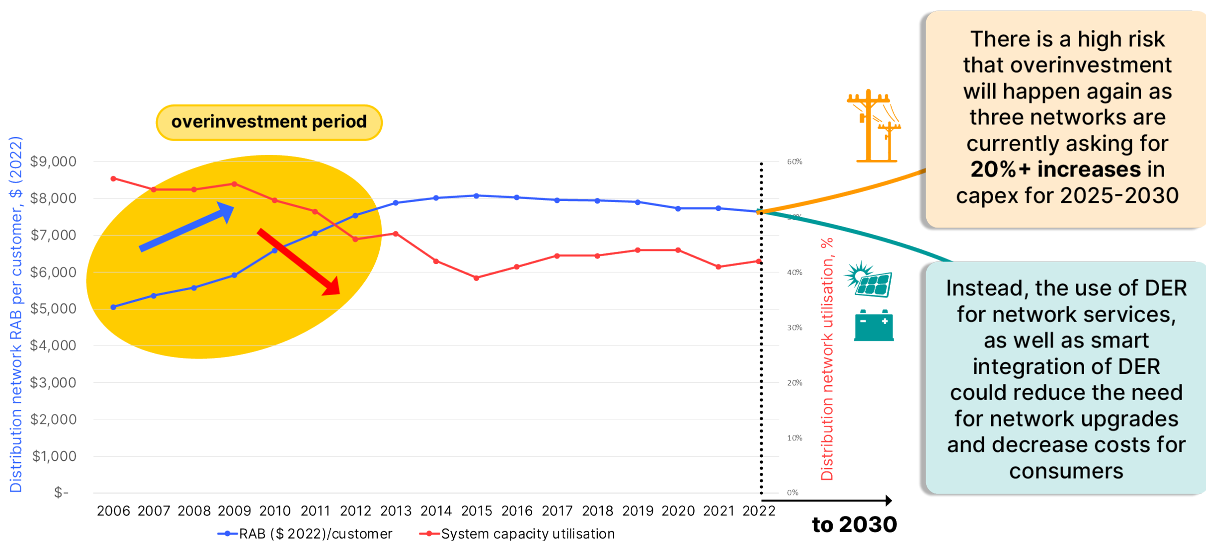
Source: IEEFA. All figures in real $2022.

[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

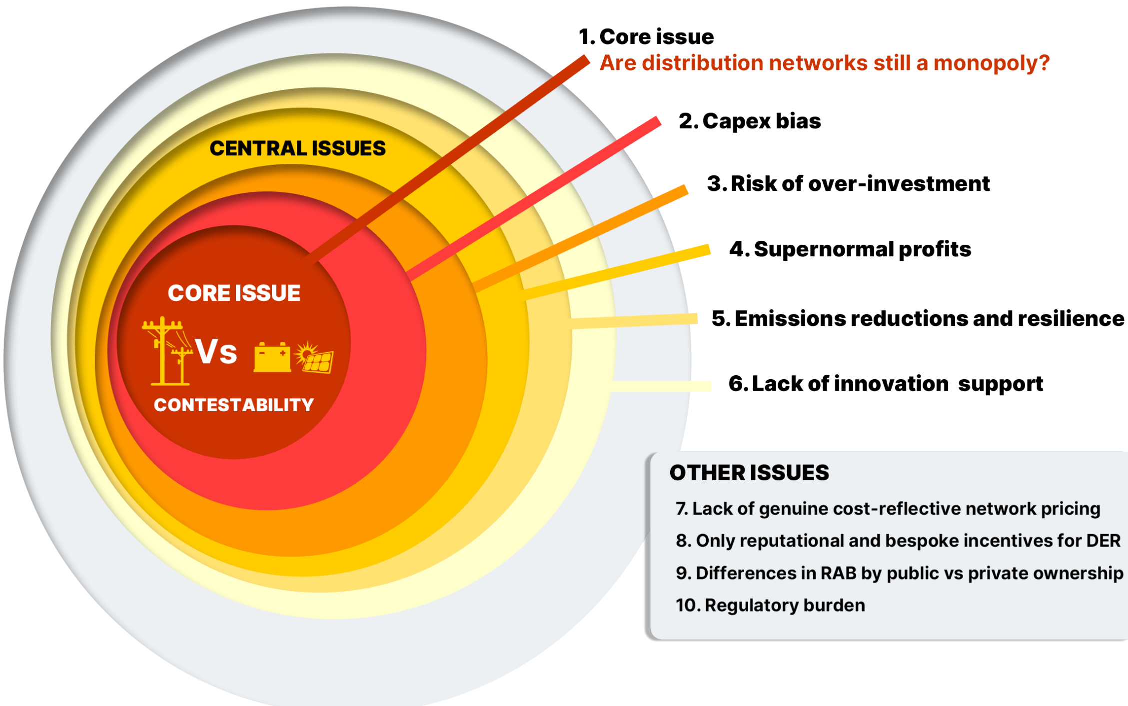


Source: IEEFA based on AER data.

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



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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

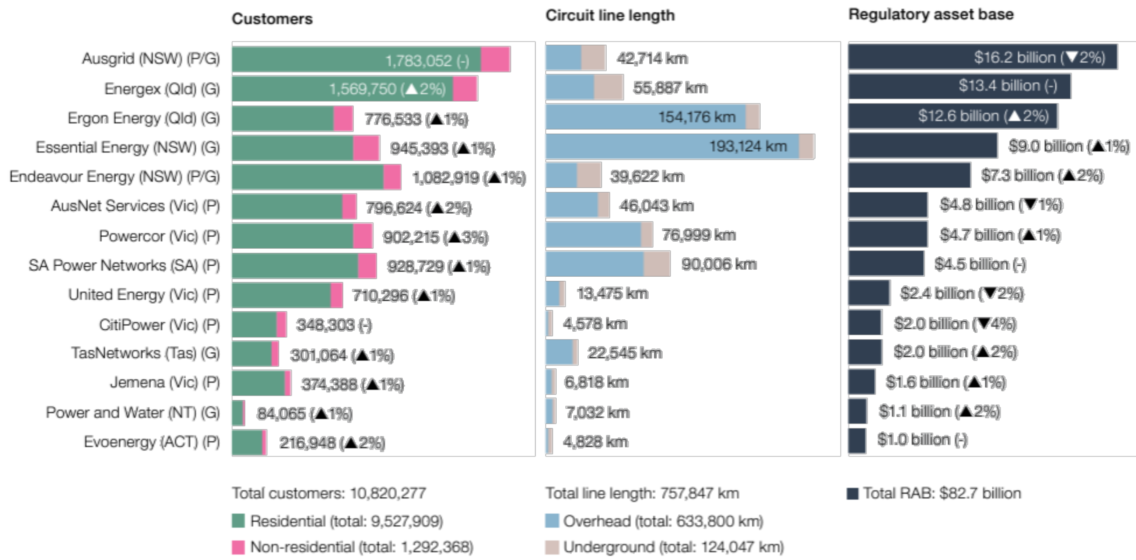
DNSP	Owners
South Australia (SA) Power Networks	Hong Kong-based Cheung Kong Infrastructure Holdings (51%); Spark Infrastructure (49%).
CitiPower and Powercor	Cheung Kong Infrastructure (CKI) (51%); Spark Infrastructure (49%).
United Energy	Cheung Kong Infrastructure (CKI) (66%); State Grid Corporation 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



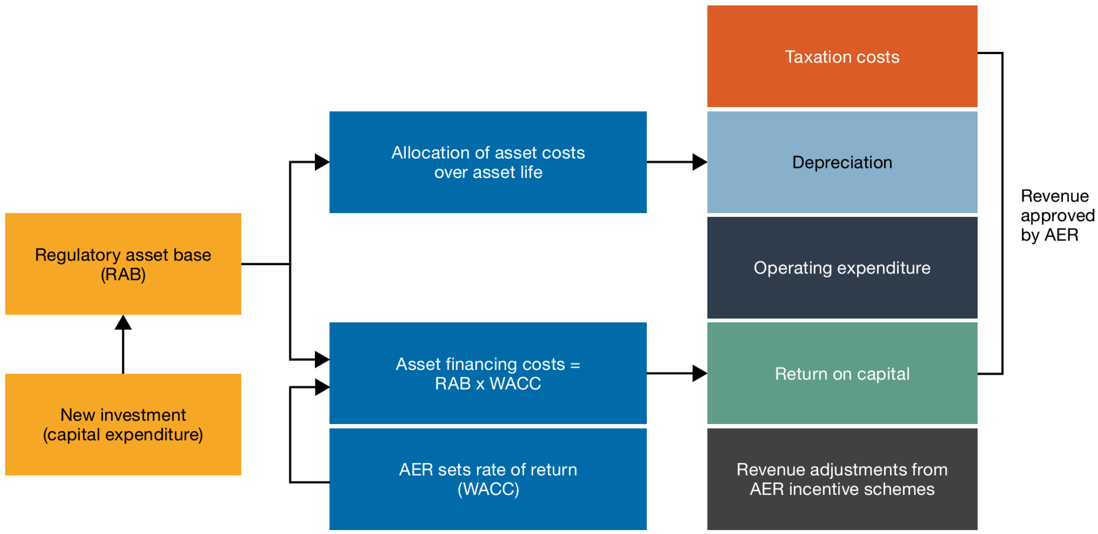
Note: (G): state government owned; (P): privately owned; GWh: gigawatt hours; km: kilometres; % values represent change from previous year. Regulatory asset base is adjusted to June 2022 dollars. Line length and regulatory asset base are as at 30 June 2022 (31 March 2022 for AusNet Services transmission). 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.

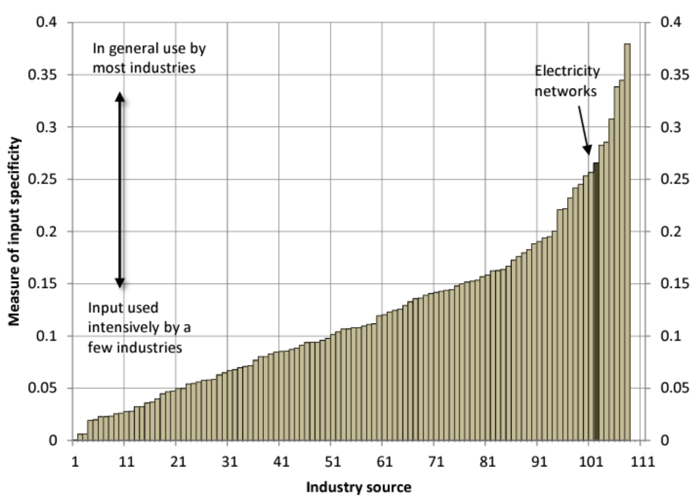
- **Multi-Year Rate Plans** – revenue set for a predetermined regulatory period.
- **Efficiency Sharing Mechanisms** – which specify how the rewards of efficiency improvement by the utility should be distributed between itself and its customers.
- **Performance Incentive Mechanisms (PIMs)** – rewards 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 $j, k \in (1 \dots N)$

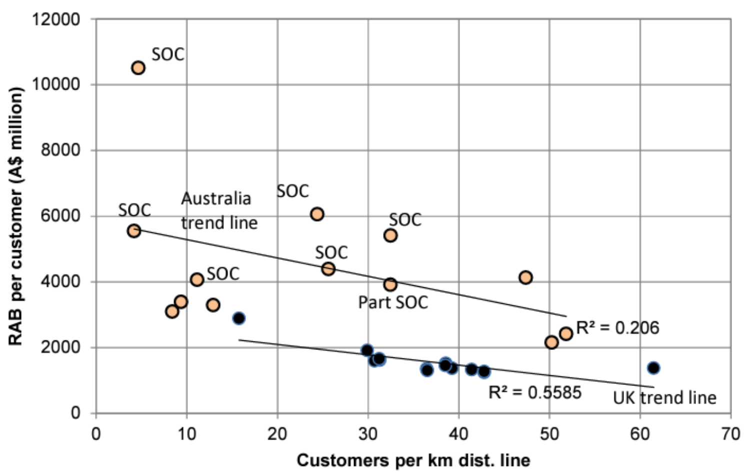
For any given industry (m) in the group 1 to N, there will be a vector of alpha values ($\mathbf{V_m}$) representing the importance of that industry as an input into other industries ($\alpha_{m1}, \alpha_{m2}, \alpha_{m3}, \dots \alpha_{mN}$). Calculate the ratio ($R_m$) of 20th and 80th percentiles 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.

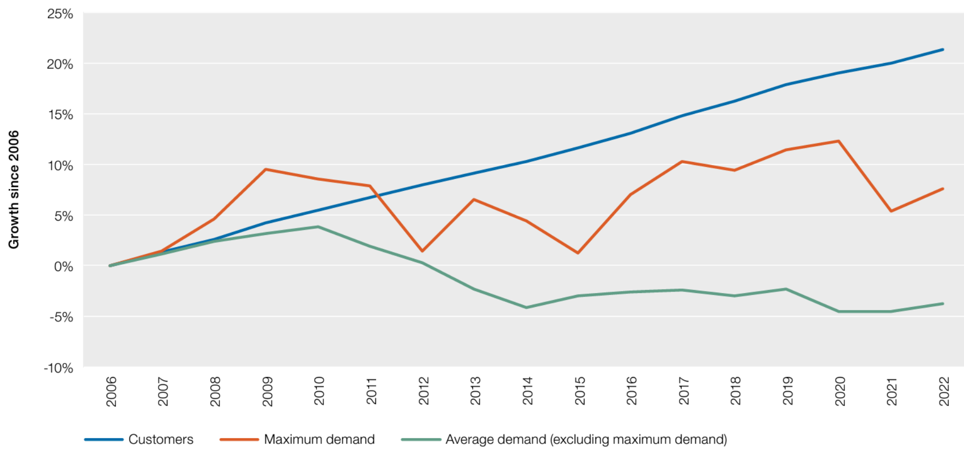
Source: Productivity Commission.

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]

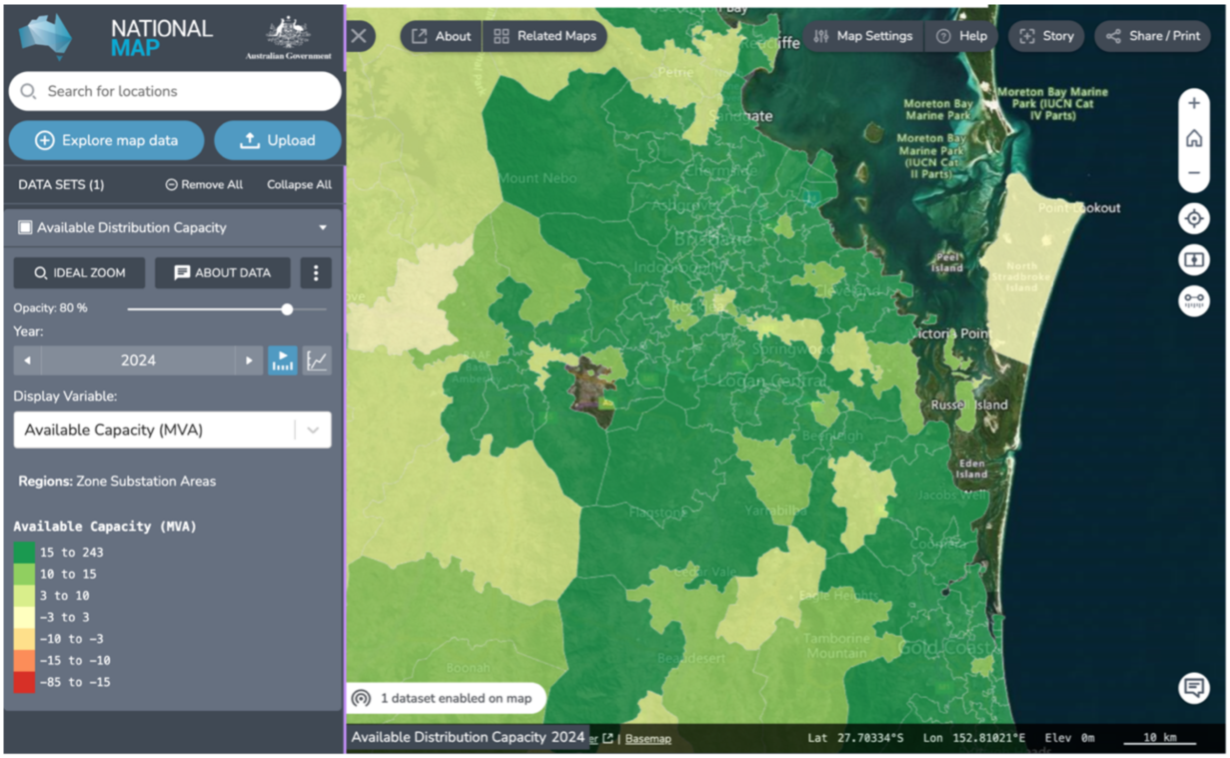
This highlights that average annual and maximum demand per connection (i.e. per customer) has decreased substantially since around 2010.[15] This has occurred against a background of widespread excess network capacity due to historical over-investment, alongside widespread adoption of distributed energy 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

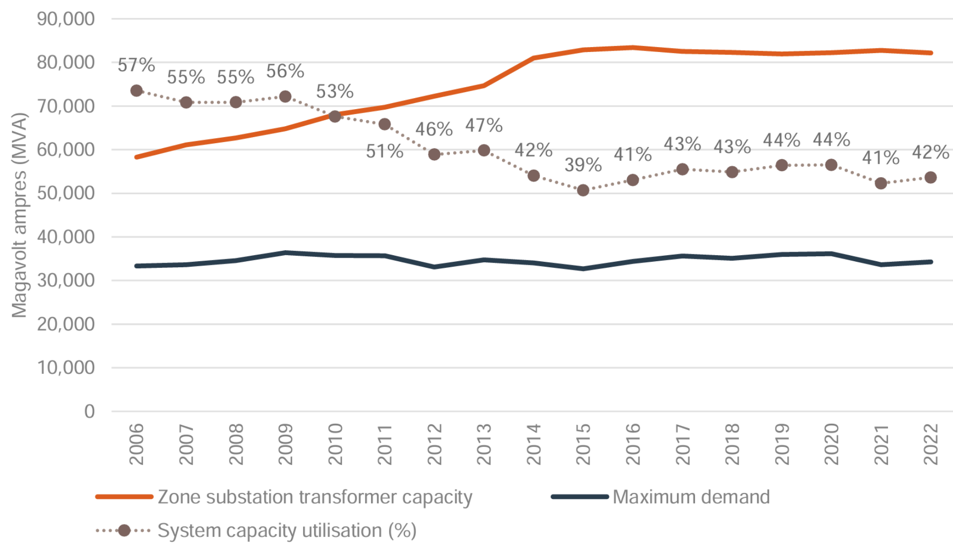


Source: National Map.

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.

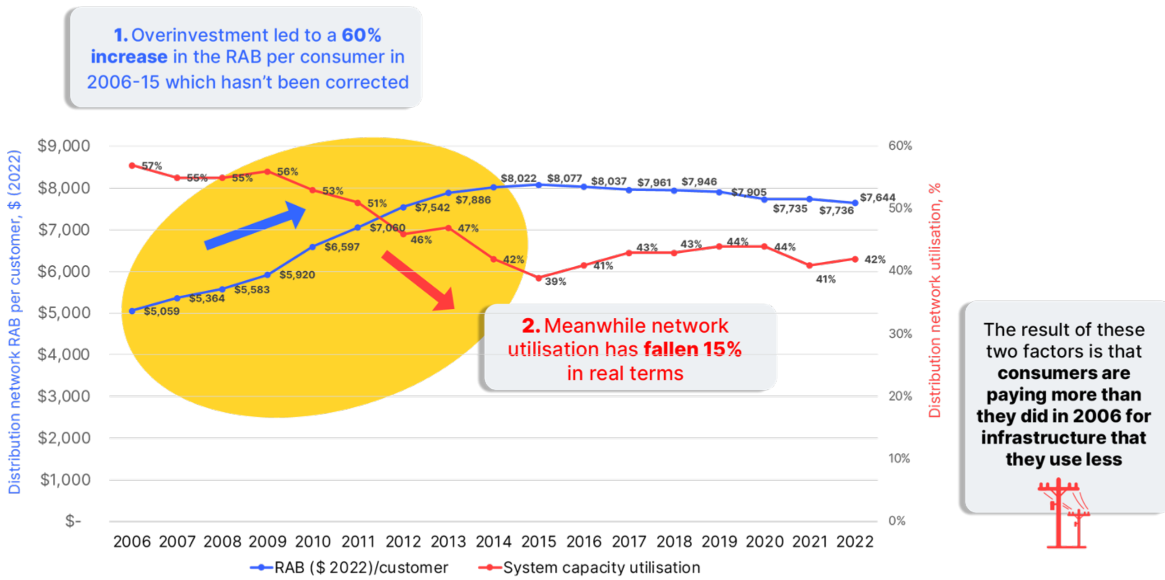
Based on AER data, we can conclude that:

- 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.

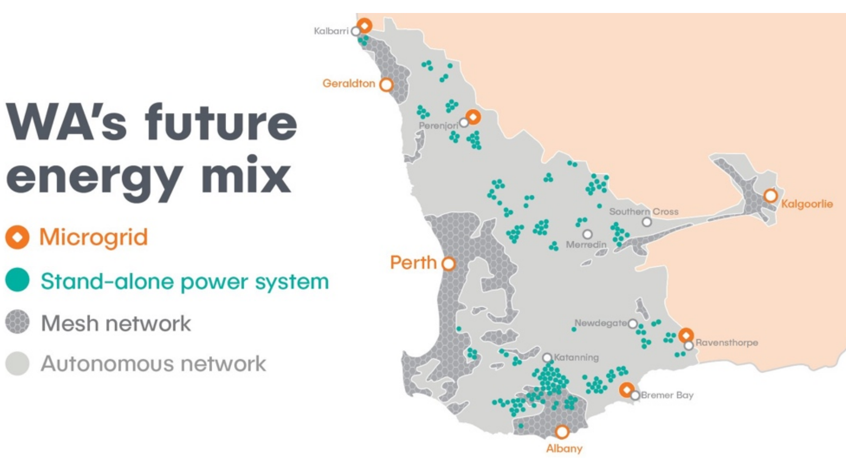
[26] ACCC. Retail Electricity Pricing Inquiry—Final Report. June 2018. Page xviii.

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

[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."

[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

[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

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[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.

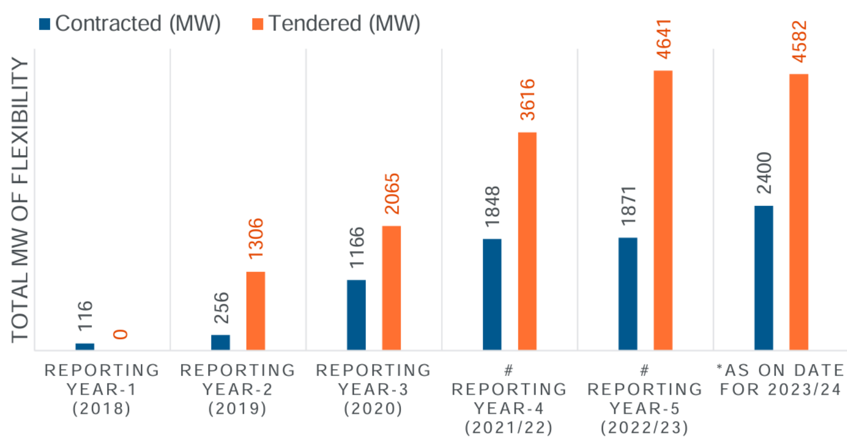
Figure 10: Indicative DER annual revenue in Great Britain in constrained locations

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.

[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]

[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

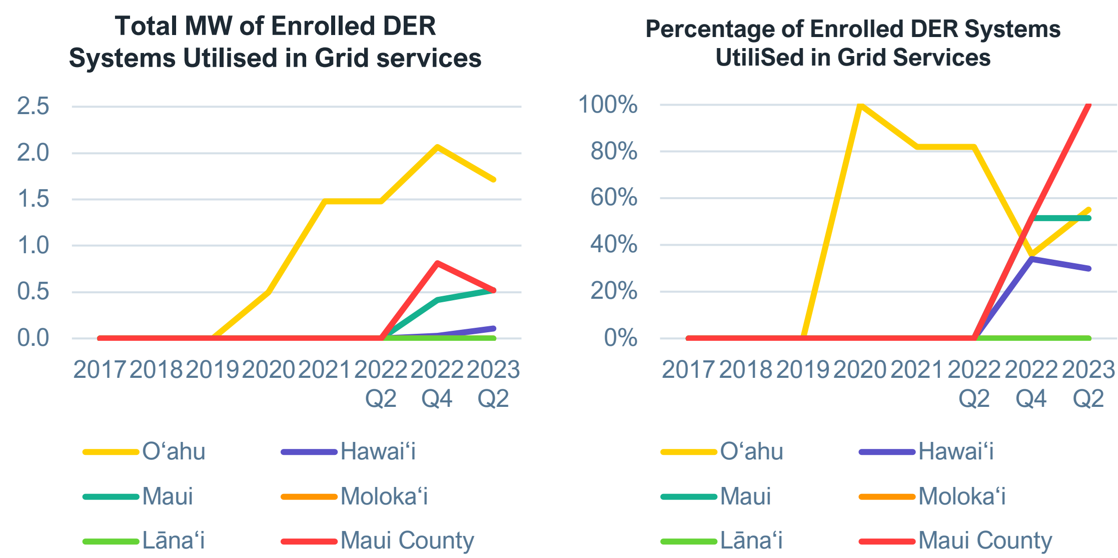
Regulatory Goal	Regulatory Outcome	
Enhance Customer Experience	Traditional	Affordability
		Reliability
	Emergent	Interconnection Experience
		Customer Engagement
Improve Utility Performance	Traditional	Cost Control
	Emergent	DER Asset Effectiveness
		Grid Investment Efficiency
Advance Societal Outcomes	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:

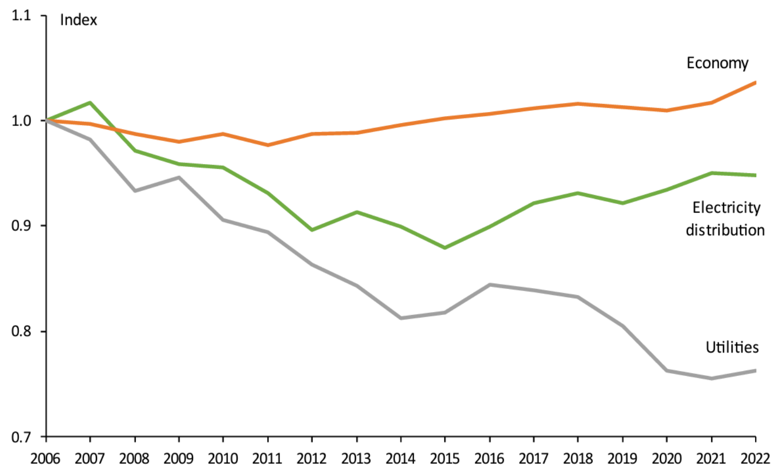
- **Customer numbers.** The number of customers is a driver of the services a DNSP must provide (about 19% weight).
- **Circuit line length.** Line length reflects the distances over which DNSPs deliver electricity to their customers (about 39% weight).
- **Ratcheted maximum demand (RMD).** DNSPs endeavour 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.

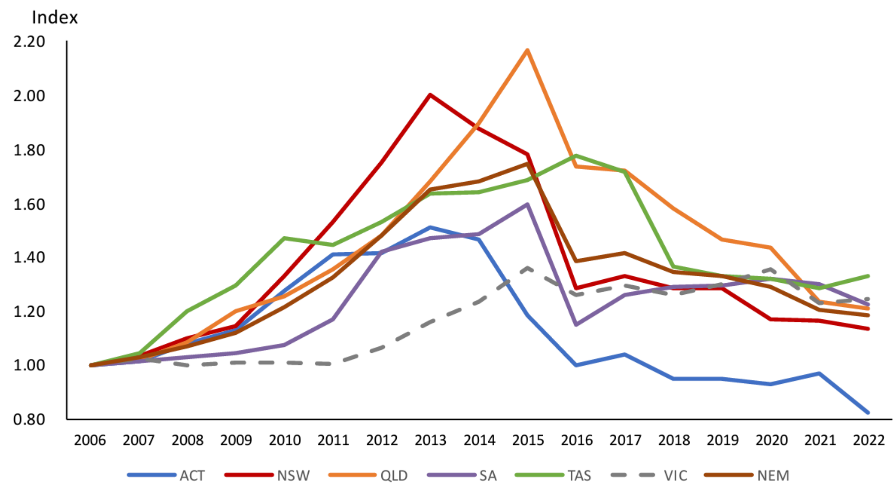
Figure 14: Electricity distribution, total, capital and opex productivity, 2006-22

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

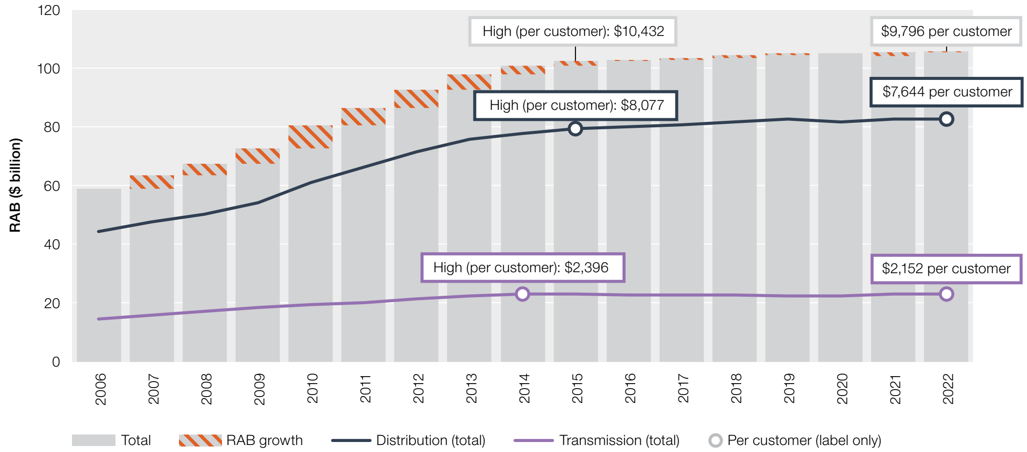


Source: AER.[150]

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)

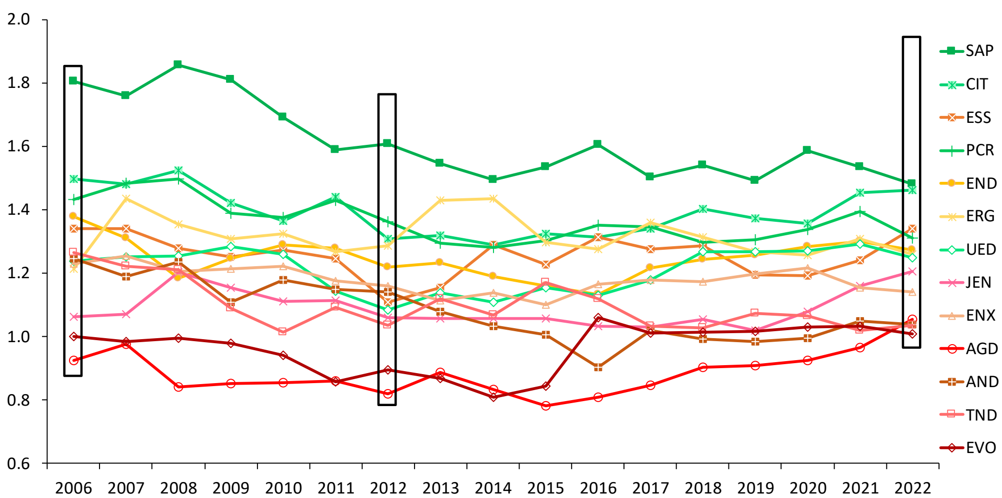


Note: All data are adjusted to June 2022 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

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

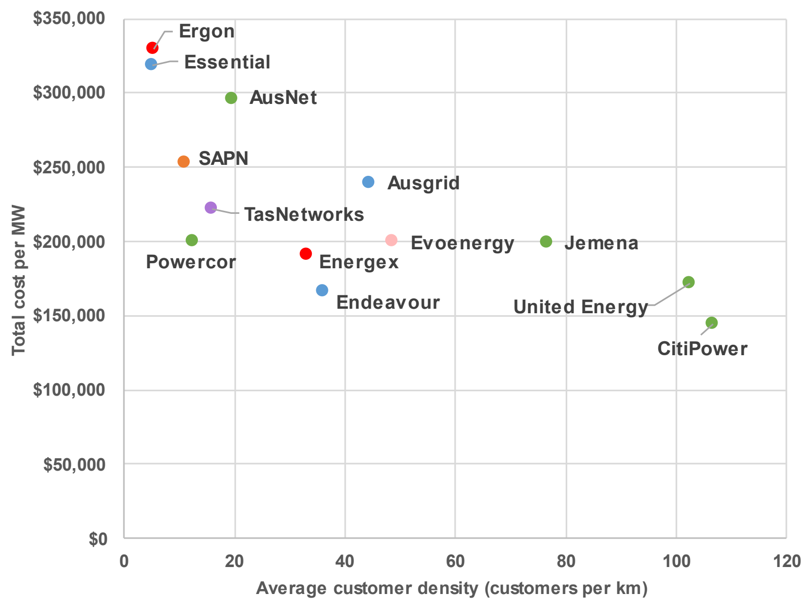


Source: AER.[153]

[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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