Source: Shutterstock

3 ELECTRICITY NETWORKS

Electricity networks transport power from generators to energy customers (infographic 1). Australia's electricity network infrastructure consists of transmission and distribution networks, as well as smaller stand-alone regional systems. This chapter covers the 21 electricity networks regulated by the Australian Energy Regulator (AER), which are located in all states and territories other than Western Australia.

3.1 Electricity network characteristics

Transmission networks transport electricity at high voltages from generators to major load centres. They consist of towers and wires, underground cables, transformers, switching equipment, reactive power devices, and monitoring and telecommunications equipment.

Electricity is injected from points along the transmission grid into *distribution* networks that distribute electricity to residential homes, and commercial and industrial premises. Distribution networks consist of poles and wires, substations, transformers, switching equipment, and monitoring and signalling equipment. Electricity is stepped down to lower voltages when it enters a distribution network, for safe delivery to customers.

While electricity distributors are responsible for transporting and delivering electricity to customers, they are not responsible for selling it. Instead, retailers purchase electricity from the wholesale market, and network services from network service providers, and sell them as a package to customers (chapter 6).

Electricity networks have traditionally provided a one-way delivery service to customers. However, the role of electricity networks is evolving as new technologies change how electricity is generated and used. Many small scale generators such as rooftop solar photovoltaic (PV) systems are now embedded within distribution networks, resulting in two-way electricity flows along the networks. Energy users with solar PV systems can now source electricity from the distribution network when they need it, and sell back the surplus electricity that they generate at other times. Electricity generated using solar PV systems is also increasingly being stored using battery storage systems.

Alongside the major distribution networks, small *embedded* distribution networks deliver energy to sites such as apartment blocks, retirement villages, caravan parks and shopping centres. Electricity is delivered to a single connection point at these sites, then sold by the embedded network operator to tenants or residents. The revenues of embedded networks are not regulated.

3.2 Geography

Electricity networks in Queensland, New South Wales (NSW), Victoria, South Australia, Tasmania and the Australian Capital Territory (ACT) create an interconnected grid forming the National Electricity Market (NEM). The AER regulates all major networks in the NEM, other than the Basslink interconnector linking Victoria with Tasmania.

The electricity networks regulated by the AER (listed in tables 3.1 and 3.2, and mapped in figure 3.1) have a combined valuation of $98.5 billion, and comprise seven transmission networks (valued at $21.4 billion) and 14 distribution networks ($77.2 billion). In total, the networks span almost 800 000 kilometres of line.

The NEM transmission grid has a long, thin, low density structure, reflecting the dispersed locations of electricity generators and demand centres. The grid consists of five state based networks linked by cross-border interconnectors. Three interconnectors (Queensland–NSW, Heywood, and Victoria–NSW) form part of the state based networks, while the other three (Directlink, Murraylink and Basslink) are separately owned (table 3.1).

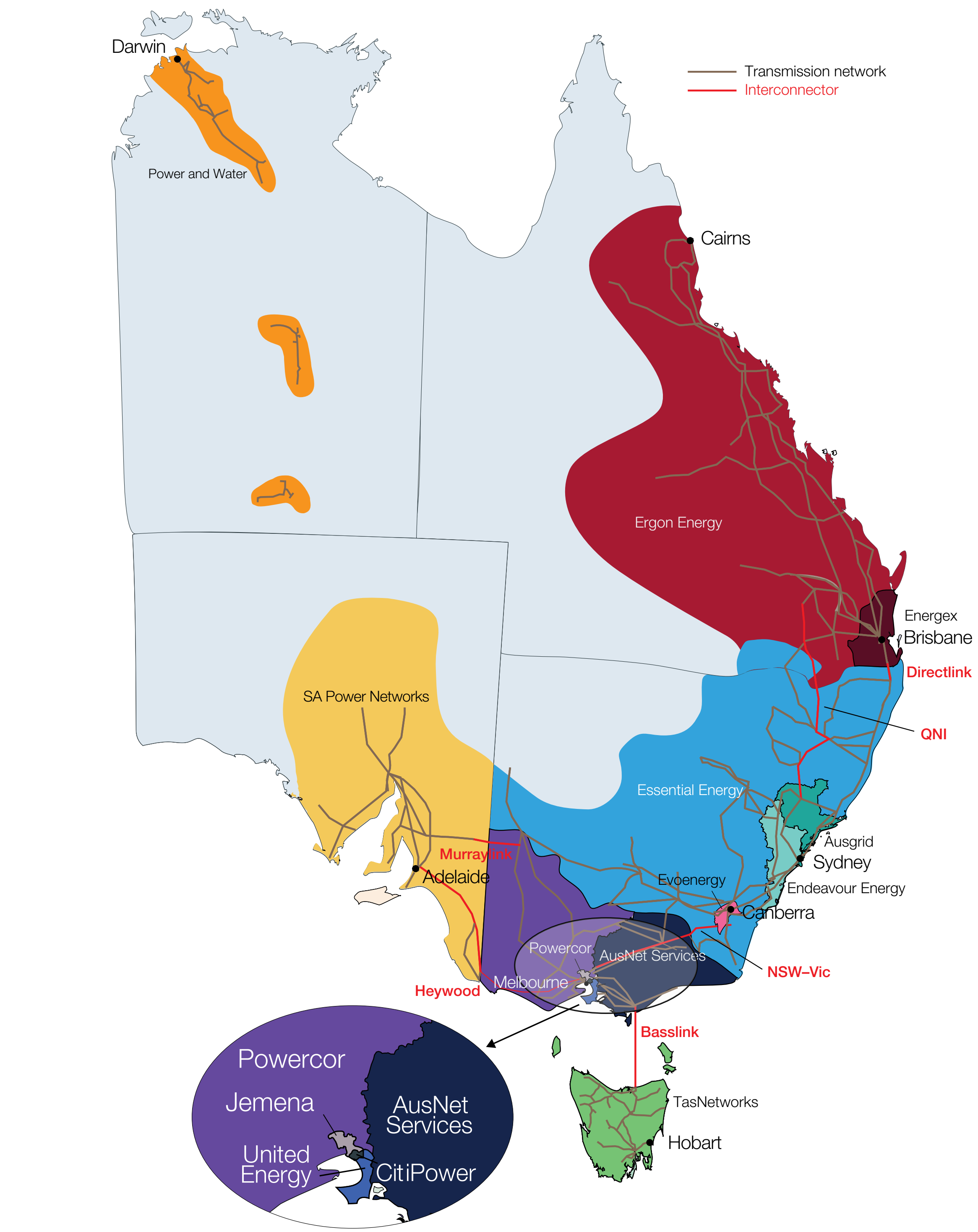
The transmission grid connects with 13 distribution networks, which transport electricity to residential homes and commercial and industrial premises.[1] Consumers in Queensland, NSW and Victoria are serviced by multiple distribution networks, each of which operates and maintains its network within a defined geographic region. Consumers in South Australia, Tasmania and the ACT are serviced by a single distribution network operating within each jurisdiction (table 3.2). The transmission grid also delivers electricity directly to some industrial customers (such as aluminium smelters).

The Northern Territory has three separate networks—the Darwin–Katherine, Alice Springs and Tennant Creek systems—that are all owned by Power and Water. The networks are classified as a single distribution network for regulatory purposes, but do not connect to each other or the NEM.

The AER does not regulate electricity networks in Western Australia, where the Economic Regulation Authority (ERA) administers state based arrangements. Western Power (owned by the Western Australian Government) is the state's principal network, covering the populated south west region,

1 Some jurisdictions also have small networks that serve regional areas.

Figure 3.1
Electricity distribution networks regulated by the AER



QNI, Queensland–NSW Interconnector.
Note: The AER does not regulate the Basslink Interconnector.
Source: AER.

including Perth. Another state owned corporation—Horizon Power—services regional and remote areas.[2]

3.3 Network ownership

Australia's electricity networks were originally government owned, but many jurisdictions have now either partly or fully privatised the assets. Privatisation of the electricity networks began in Victoria, which sold its transmission and distribution networks to private entities in the 1990s.[3]

In 2000 the South Australian Government privatised its transmission network and leased its distribution network. In the same year, a joint venture between the ACT Government and private equity holders was established to operate the ACT distribution network.[4]

The NSW Government leased its transmission network (TransGrid) to private interests in November 2015. It then leased 50.4 per cent of two distribution networks—Ausgrid in 2016 and Endeavour Energy in 2017. The predominately rural Essential Energy network remains government owned and operated.

Ownership of the privatised networks in NSW, Victoria and South Australia is concentrated among relatively few entities. These entities include Hong Kong's Cheung Kong Infrastructure Holdings Limited (CKI Group) and Power Assets Holdings, Singapore Power International, and State Grid Corporation of China (tables 3.1 and 3.2). Fund managers such as Spark Infrastructure and Hastings also have significant equity in the sector. Significant ownership links exist across the electricity and gas network sectors (section 5.2).

Electricity networks in Queensland, Tasmania, the Northern Territory and Western Australia remain wholly government owned. The Queensland Government in 2016 merged state owned electricity distributors Energex and Ergon Energy under a new parent company, Energy Queensland.

In some jurisdictions, ownership of electricity networks overlaps with other industry segments, with ring-fencing for operational separation. Queensland's state owned Ergon Energy, for example, provides both distribution and retail services in regions outside south east Queensland.

2 For further information, see the Western Australian Department of Treasury (www.treasury.wa.gov.au) and ERA (www.era.wa.gov.au) websites.
3 In Victoria, ownership of the transmission network is separated from planning and investment decision making. AusNet Services owns the state's transmission assets, but the Australian Energy Market Operator (AEMO) plans and directs network augmentation (expansion). AEMO also purchases bulk network services from AusNet Services for sale to customers.
4 The ACT has no transmission assets.

3.4 How network prices are set

Electricity networks are capital intensive, so their average costs will fall as output rises. This characteristic gives rise to a natural monopoly industry structure, where it is more efficient to have a single network provider than to have multiple providers offering the same service.

Because monopolies face no competitive pressure, they have opportunities and incentives to charge unfair prices. This environment poses serious risks to consumers, given network charges can make up close to 50 per cent of a residential electricity bill (figure 6.2 in chapter 6). To counter these risks, the role of the AER as economic regulator is to mimic the incentives that network businesses would face in a competitive market to control their costs, invest efficiently, and not overcharge consumers.

3.4.1 Regulatory objective and approach

The National Electricity Law and the National Electricity Rules set the framework for regulating electricity networks, and the AER applies that framework. The regulatory objective of the National Electricity Law is to promote efficient investment in, and operation and use of, electricity services for the long term interest of consumers, in terms of the price, quality, safety, reliability and security of supply.

The AER seeks to ensure consumers pay no more than necessary for the safe and reliable delivery of electricity. Its regulatory toolkit to pursue this objective is wide ranging (box 3.1), but its central role is to set the maximum revenue that a network business can earn from its customers for delivering electricity. The AER undertakes this role via a periodic determination or reset process, in which it assesses how much revenue a prudent network business would need to cover its efficient costs. Network revenues are then capped at this level for the regulatory period, which is typically five years.[5]

5 While a five year regulatory period helps to create a stable investment environment, it poses risks of locking in inaccurate forecasts. The National Electricity Rules include mechanisms for dealing with uncertainties—such as cost pass-through triggers, and a process for approving contingent investment projects—when costs were not clear at the time of the reset.

Table 3.1 Electricity transmission networks in the NEM

NETWORK	LOCATION	LINE LENGTH (KM)[1]	ELECTRICITY TRANSMITTED (GWH)[2]	MAXIMUM DEMAND (MW)[3]	ASSET BASE ($ MILLION)[1]	CURRENT REGULATORY PERIOD[4]	OWNER
STATE NETWORKS[5]							
Powerlink	Qld	14 526	53 765	12 201	7 300	1 July 2017 – 30 June 2022	Queensland Government
TransGrid	NSW	13 052	74 400	18 700	6 600	1 July 2018 – 30 June 2023	Hastings 20%; Spark Infrastructure 15%; other private equity 65%
AusNet Services / AEMO	Vic	6 628	41 480	9 668	3 300	1 April 2017 – 31 March 2022	Listed company (Singapore Power 31.1%, State Grid Corporation 19.9%)
ElectraNet	SA	5 513	13 787	3 527	2 600	1 July 2018 – 30 June 2023	State Grid Corporation 46.6%; YTL Power Investments 33.5%; Hastings Investment Management 19.9%
TasNetworks	Tas	3 545	12 885	2 353	1 500	1 July 2019 – 30 June 2024	Tasmanian Government
TOTAL		43 264	196 317		21 400		
STANDALONE INTERCONNECTORS							
Directlink	Qld–NSW	63			144	1 July 2020 – 30 June 2025	Energy Infrastructure Investments (Marubeni Corporation 49.9%, Osaka Gas 30.2%, APA 19.9%)
Murraylink	Vic–SA	180			117	1 July 2018 – 30 June 2023	Energy Infrastructure Investments (Marubeni Corporation 49.9%, Osaka Gas 30.2%, APA 19.9%)
Basslink	Vic–Tas	375				Unregulated	Keppel Infrastructure Trust
INTERCONNECTORS FORMING PART OF STATE NETWORKS							
Queensland to NSW (QNI)	Qld–NSW	235				As for Powerlink and TransGrid	Powerlink and TransGrid
Heywood	Vic–SA	200				As for ElectraNet and AusNet Services	ElectraNet and AusNet Services
Victoria to NSW	Vic–NSW	150				As for AusNet Services and TransGrid	AusNet Services and TransGrid

GWh, gigawatt hours; km, kilometres; MW, megawatts.

1. Line length and asset base at 30 June 2019 (30 March 2019 for AusNet Services).
2. Electricity transmitted in 2018–19 (year to March 2019 for AusNet Services).
3. Non-coincident, summated maximum demand in 2018–19 (year to March 2019 for AusNet Services).
4. Current regulatory period at 1 July 2020.
5. Northern Territory transmission assets are treated as part of the distribution system for regulatory purposes.

Source: AER revenue decisions and economic benchmarking regulatory information notices (RINs); Australian Securities Exchange (ASX) release; company websites; company annual reports.

As part of the reset process, a network business submits a proposal to the AER, setting out how much revenue it will need to cover the costs of providing a safe and reliable electricity supply in the upcoming regulatory period. If the AER concludes a business's proposal is likely to be unreasonably costly, it may ask for more detailed information or a clearer business case.

Subsequently, the AER may amend a network's proposal to ensure the network's cost forecasts are efficient.

While the AER determines efficient operating and capital expenditure, it does not approve or disapprove individual projects. Each network business prioritises its own spending programs, but it must undertake a cost–benefit analysis for any new investment project (section 3.10.5).

Table 3.2 Electricity distribution networks regulated by the AER

NETWORK	CUSTOMER NUMBERS[1]	LINE LENGTH (KM)[1]	CUSTOMER DENSITY (CUST/KM)	CURRENT REGULATORY PERIOD[2]	OWNER
QUEENSLAND					
Energex	1 496 317	54 777	27.3	1 July 2020 – 30 June 2025	Queensland Government
Ergon Energy	765 924	152 279	5.0	1 July 2020 – 30 June 2025	Queensland Government
NSW AND ACT					
Ausgrid	1 746 274	42 007	41.6	1 July 2019 – 30 June 2024	NSW Government 49.6%; IFM Investors 25.2%; AustralianSuper 25.2%
Endeavour Energy	1 027 586	38 284	26.8	1 July 2019 – 30 June 2024	Private sector consortium 50.4%; NSW Government 49.6%
Essential Energy	916 471	192 538	4.8	1 July 2019 – 30 June 2024	NSW Government
Evoenergy	198 432	5 435	36.5	1 July 2019 – 30 June 2024	Icon Distribution Investments 50%; Jemena 50% (State Grid Corporation 60%, Singapore Power 40%)
VICTORIA[2]					
AusNet Services	762 382	45 494	16.8	1 January 2016 – 31 December 2020	Listed company (Singapore Power 31.1%, State Grid Corporation 19.9%)
CitiPower	345 009	4 558	75.7	1 January 2016 – 30 December 2020	Cheung Kong Infrastructure / Power Assets Holdings 51%; Spark Infrastructure 49%
Jemena	354 452	6 628	53.5	1 January 2016 – 30 December 2020	Jemena (State Grid Corporation 60%, Singapore Power 40%)
Powercor	853 771	75 815	11.3	1 January 2016 – 30 December 2020	Cheung Kong Infrastructure / Power Assets Holdings 51%; Spark Infrastructure 49%
United Energy	697 594	13 408	52.0	1 January 2016 – 30 December 2020	Cheung Kong Infrastructure 66%; Jemena 34% (State Grid Corporation 60%, Singapore Power 40%)
SOUTH AUSTRALIA					
SA Power Networks	906 198	89 298	10.1	1 July 2020 – 30 June 2025	Cheung Kong Infrastructure / Power Assets Holdings 51%; Spark Infrastructure 49%
TASMANIA					
TasNetworks	290 446	22 862	12.7	1 July 2019 – 30 June 2024	Tasmanian Government
NORTHERN TERRITORY					
Power and Water[3]	85 743	7 103	12.1	1 July 2019 – 30 June 2024	Northern Territory Government
TOTAL	10 446 598	750 487	13.9		

km, kilometres; cust/km, number of customers per km of power line.

1. Customer numbers, line length and asset base as at 30 June 2019 (31 December 2019 for Victorian businesses).

2. The Victorian government has indicated it's intention to bring Victoria into alignment with the other NEM states to operate on a financial year—rather than calendar year—basis. The intention is for this change to come into effect for the 1 July 2021 to 30 June 2026 regulatory control period. It will mean extending the current regulatory period by six months.

3. For regulatory purposes, Northern Territory transmission assets are treated as part of the distribution system.

Source: ASX releases; company websites; company annual reports.

The regulatory framework also allows network businesses to earn bonus revenue (or incur a revenue penalty) under incentive schemes operated by the AER.

The schemes encourage businesses to:

- efficiently manage their operating and capital expenditure
- improve service provision in ways that customers value
- adopt demand management schemes that take strain off the network, and avoid or delay network investment.

Box 3.1 The AER's role in electricity network regulation

The Australian Energy Regulator (AER) sets a cap every five years on the revenue that a network business can earn from its customers. Alongside this central role, we undertake broader regulatory functions, including:

- assessing network charges each year to ensure they reflect underlying costs and do not breach revenue limits
- providing incentives for network businesses to improve their performance in ways that customers value
- assessing whether any additional costs not anticipated at the time of our original decision should be passed on to customers
- publishing information on the performance of network businesses, including benchmarking analysis
- monitoring whether network businesses properly assess the merits of new investment proposals.

We also help implement reforms to improve the quality of network regulation and achieve better outcomes for energy customers, such as:

- adopting a more consumer centric approach to setting network revenues (section 3.6)
- implementing the Power of Choice reforms, which empower customers to make informed choices about their energy use, and ultimately help keep network costs down (sections 3.7 and 1.8)
- publishing more information on network profitability (section 3.8.1)
- reviewing how rates of return and taxation allowances are set for energy networks (section 3.11).

The AER publishes guidelines on its approach to assessing costs and applying incentives. Sections 3.10, 3.12 and 3.14 examine the incentive schemes in more detail.

In conducting its assessment, the AER draws on a range of inputs, including cost forecasts, benchmarking, and revealed costs from past expenditure. It engages closely with stakeholders from the earliest stage of the process, including before networks lodge a formal proposal.

The regulatory process increasingly focuses on how network businesses engage with their customers in shaping regulatory proposals. As part of this focus, the AER is trialling the 'New Reg' process—an enhanced, more open approach to how network businesses incorporate consumer perspectives in developing their regulatory proposals—with Victorian distribution network AusNet Services (box 3.3).

Additionally, the AER's Consumer Challenge Panel—comprising experienced and highly qualified individuals with consumer, regulatory and/or energy expertise—provides input on issues of importance to consumers. It advises the AER on whether the revenue proposals submitted by network businesses are in the long term interests of consumers; the effectiveness of network businesses' engagement with their customers; and how consumer views are reflected in the development of the network businesses' proposals.

3.4.2 Building blocks of network revenue

The AER uses a 'building block' approach to assess a network business's revenue needs. Specifically, it forecasts how much revenue the business will need to cover:

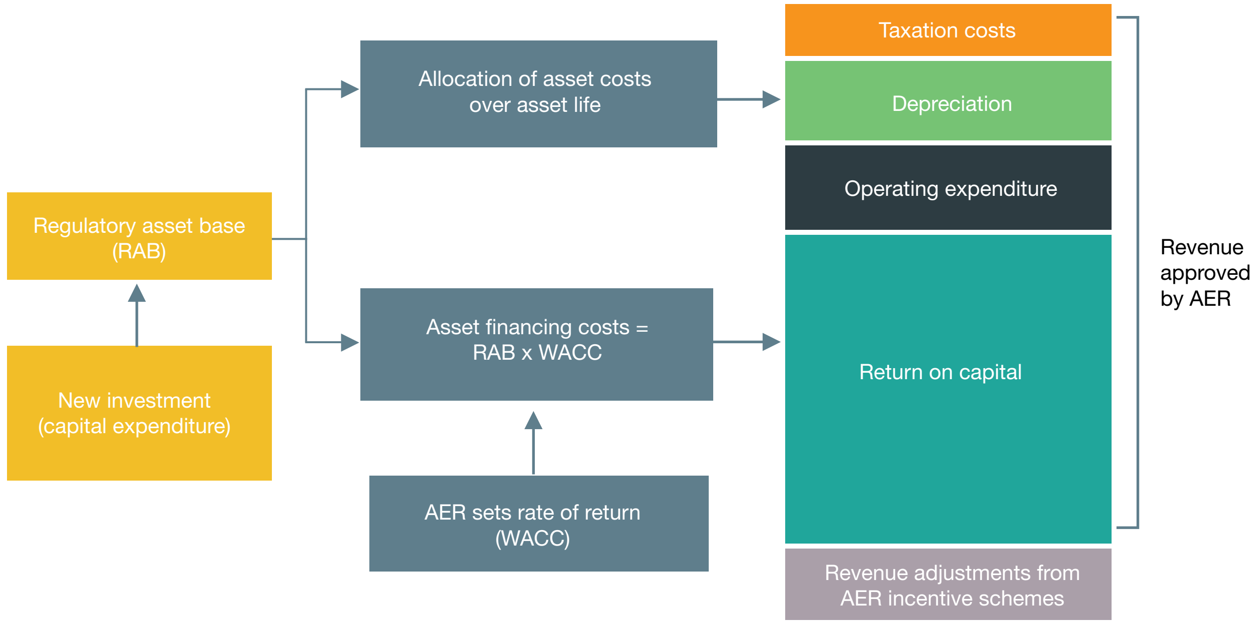
- efficient operating and maintenance costs
- asset depreciation costs
- forecast taxation costs
- a commercial return to investors that fund the network's assets and operations.

The AER also makes revenue adjustments for over- or under-recovery of revenue made in the past, and for incentive schemes (figure 3.2).

While network businesses are entitled to earn revenue to cover their efficient costs each year, this revenue does *not* include the full cost of investment in new assets made during the year. Network assets have a long life, so the cost of investment in new assets is recovered over the economic life of the assets, which may run to several decades. The amount recovered each year is called *depreciation*, and reflects the lost value of network assets each year through wear and tear, and technical obsolescence.

Additionally, the shareholders and lenders that fund these assets must be paid a commercial return on their investment. The AER sets the rate of return (also called the

Figure 3.2
Forecasting network revenue



AER, Australian Energy Regulator; RAB, regulatory asset base; WACC, weighted average cost of capital.

Note: Revenue adjustments from incentive schemes encourage network businesses 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.

weighted average cost of capital, or WACC). The size of this return depends on:

- the value of the network's assets, measured by the regulatory asset base (RAB) plus forecast new capital expenditure
- the rate of return that the AER allows based on the forecast cost of funding those assets through equity and debt.[6]

These returns take up the largest slice of revenue, accounting for 45 per cent across all networks (49 per cent for transmission networks, and 44 per cent for distribution networks) (figure 3.3).

Operating costs—such as maintenance costs and overheads—absorb 35 cent of revenue across all networks (30 per cent for transmission, and 36 per cent for distribution). Depreciation absorbs another 17 per cent of revenue. Taxation and other costs account for the remainder of network revenue. Sections 3.10–3.12 examine major cost components in more detail.

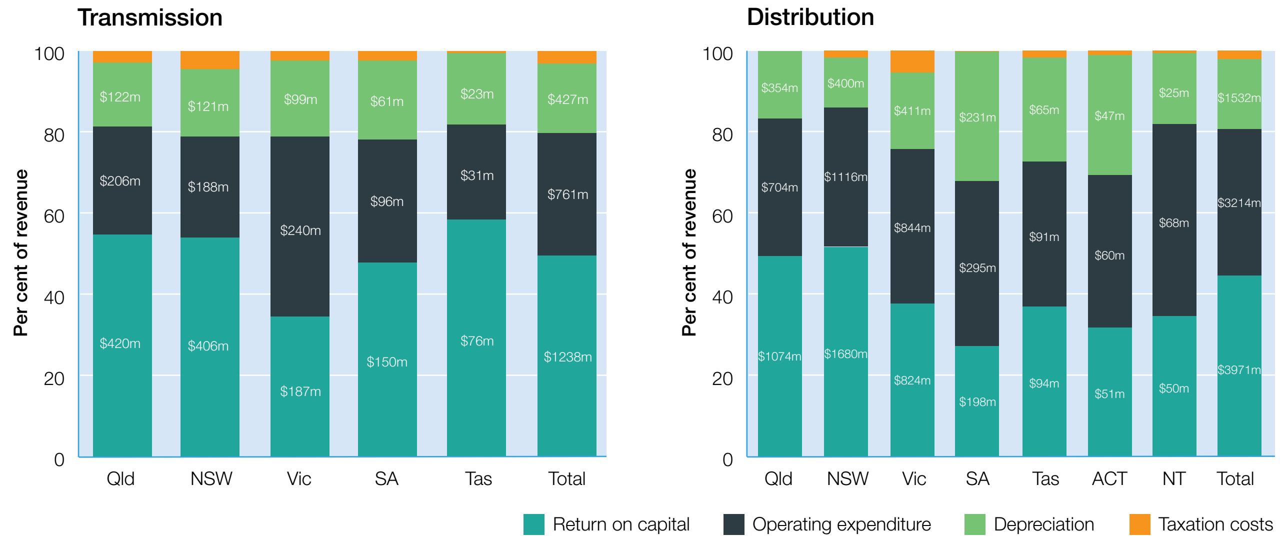
6 The return on equity is the return that shareholders of the business will require for them to continue to invest. The return on debt is the interest rate that the network business pays when it borrows money to invest.

3.4.3 Timelines and process

The National Electricity Law and the National Electricity Rules set the regulatory framework and process, which is both lengthy and highly consultative. The process begins around three years before a new regulatory period, when the AER works with stakeholders on a review framework and approach. The next step is for a network business to propose the revenue that it needs to cover the efficient costs of meeting its service and reliability obligations. Network businesses engage with their customers in framing the revenue proposal.

The AER has 15 months to formally review a revenue proposal before releasing a final decision. The AER's review includes an assessment of the reasonableness of the network business's forecasts and the efficiency of expenditure proposals. It consults widely with energy customers, consumer representatives, government, investment groups, network businesses and other stakeholders. This consultation includes issues papers, draft decisions and public forums. The timing of the AER reviews is staggered to avoid bunching (figures 3.4 and 3.5).

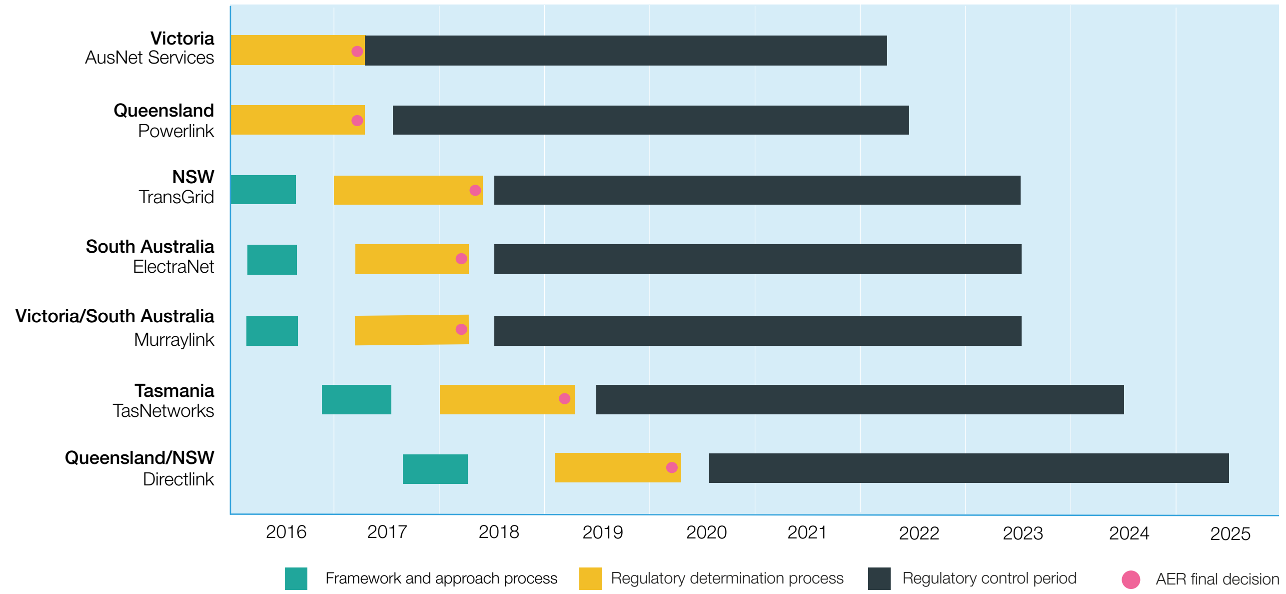
Figure 3.3
Composition of average annual network revenue



Note: Network businesses also receive bonuses or penalties that impact on annual network revenues. These bonuses/penalties are not material and are not considered in this chart.

Source: Post tax revenue modeling used in AER determination process.

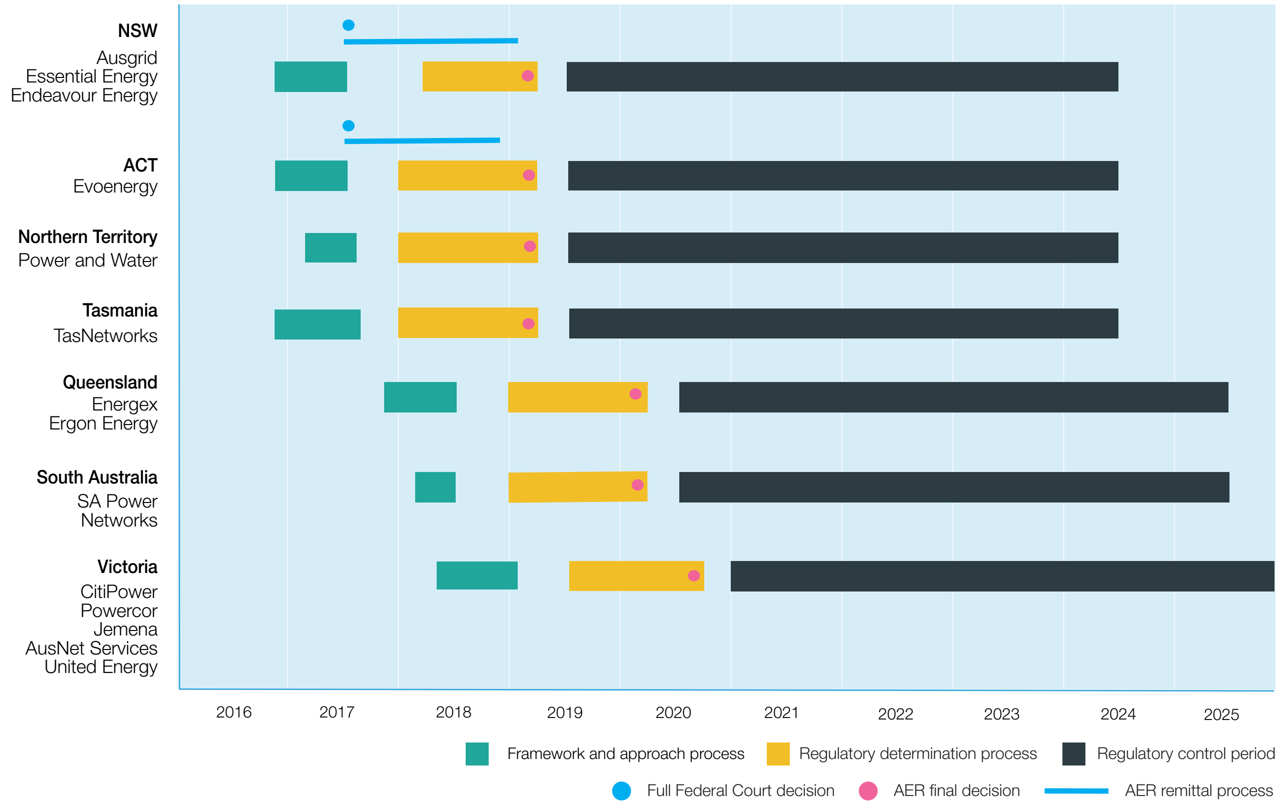
Figure 3.4
AER decision timelines—electricity transmission networks



Note: Timelines for AER decisions effective at 1 July 2020. The latest information is available at www.aer.gov.au/networks-pipelines/determinations-access-arrangements.

Source: AER.

Figure 3.5
AER decision timelines—electricity distribution networks



Note: Timelines effective at June 2020. The Victorian Government has noted its intention to shift network periods to a financial year—rather than calendar year—basis, commencing with the 1 July 2021 to 30 June 2026 regulatory control period. It will mean extending the current regulatory period by six months. The latest information is available at www.aer.gov.au/networks-pipelines/determinations-access-arrangements.

Source: AER.

Following its review, the AER makes a final decision setting the maximum revenue that a network business can earn from its customers through network charges.[7] While the decision sets network revenues rather than prices, the two are closely related. Network businesses set prices by spreading their allowed revenue across the customer base.[8] As part of the regulatory process (section 3.7.1), the AER assesses tariff structure statements that set out a network's pricing policies, and annually reviews prices to ensure they are consistent with the revenue decision and reflect efficient costs.

7 For transmission networks, the AER determines a cap on the maximum revenue that a network can earn during a regulatory period. For distribution networks, revenue caps apply in all states except the ACT, where an average revenue cap links revenue to volumes of electricity sold.

8 Traditionally, each customer paid a fixed daily charge plus a charge based on actual energy use. These arrangements are evolving under new pricing structures that encourage customers to consider how their energy use impacts network costs. Pricing reforms to address this issue form part of the Power of Choice program (section 3.7).

3.5 Recent AER revenue decisions

Since January 2019 the AER has finalised revenue decisions for electricity distribution networks in Queensland (Energex and Ergon Energy), NSW (Ausgrid, Endeavour Energy and Essential Energy), South Australia (SA Power Networks), Tasmania (TasNetworks), the ACT (Evoenergy), and the Northern Territory (Power and Water). The AER also finalised its revenue decision for the electricity transmission network in Tasmania (TasNetworks) and for the Directlink interconnector between NSW and Queensland. These decisions all cover a five year regulatory period (table 3.3).

Each of the AER's distribution decisions since January 2019 approved *lower* revenues than in the previous regulatory period. The AER's decisions for the previous regulatory period challenged network businesses to deliver services more efficiently through prudent choices about operating and capital expenditure, without compromising network safety and reliability. The AER's setting of lower revenue allowances for the current period acknowledged network businesses are rationalising their operations and will continue to build on operational efficiencies. Lower revenue allowances benefit customers by locking in efficiency gains.

Table 3.3 Recent AER revenue decision—key outcomes

NETWORK	LOCATION	DECISON DATE	FORECAST CHANGE FROM PREVIOUS REGULATORY PERIOD: REVENUE (%)	OPERATING EXPENDITURE (%)	CAPITAL EXPENDITURE (%)	RATE OF RETURN (%)[1]	ANNUAL RETAIL BILL IMPACT (%)[2]
TRANSMISSION NETWORKS							
TasNetworks	Tas	30 April 2019	↓ 27.8	↓ 11.9	↑ 9.1	5.5	↑ 0.6
DISTRIBUTION NETWORKS							
Energex	Qld	5 June 2020	↓ 26.5	↓ 4.3	↓ 23.7	4.7	↓ 0.8
Ergon Energy	Qld	5 June 2020	↓ 23.3	↓ 8.6	↓ 17.8	4.7	↓ 0.8
Ausgrid	NSW	30 April 2019	↓ 20.0	↓ 17.4	↓ 5.8	5.7	↓ 0.7
Endeavour Energy	NSW	30 April 2019	↓ 15.4	↓ 1.5	↑ 9.0	5.7	↓ 0.3
Essential Energy	NSW	30 April 2019	↓ 12.3	↓ 7.3	↓ 6.2	5.8	↑ 0.2
SA Power Networks	SA	5 June 2020	↓ 8.2	↑ 10.4	↓ 6.2	4.8	↓ 0.4
TasNetworks	Tas	30 April 2019	↓ 3.1	↑ 6.5	↓ 1.0	5.3	↑ 0.6
Evoenergy	ACT	30 April 2019	↓ 19.6	↑ 3.9	↓ 17.4	5.5	↑ 0.5
Power and Water	NT	30 April 2019	↓ 15.8	↓ 20.9	↑ 14.4	4.9	↓ 0.8

1. Rate of return is the nominal vanilla rate for the first year of a determination. The rate is updated annually to reflect changes in debt costs.
2. Retail bill impact is the change in the average annual customer bill compared with the customer bill in the final year of the previous period, adjusted for inflation, assuming retailers pass through outcomes of the decision.

Source: AER estimates.

As an example, for the regulatory period commencing July 2019, the AER approved capital expenditure for Ausgrid (NSW) that was 6 per cent lower than the network business invested over the previous regulatory period. This lowering of capital expenditure will reduce Ausgrid's RAB and the revenue that it recovers from customers to service those assets.

The AER's 2020 decisions for the Queensland and South Australian distribution networks were made against the backdrop of the COVID-19 pandemic. The full effect of the pandemic was uncertain at the time of the AER's determinations. The AER based its decisions on information and forecasts that could reasonably be made at the time, but it recognised there are uncertainties around how COVID-19 will affect the operations and costs of the Queensland and South Australian distribution networks during the regulatory period. If it becomes clear that the impacts of COVID-19 are substantial, then a rule change would need to be considered to enable the AER to re-open existing revenue determinations.

3.5.1 Legal reviews of AER decisions

A party can seek judicial review of an AER decision on a network business's revenue. Before October 2017 a party could also apply to the Australian Competition Tribunal (the Tribunal) for a limited merits review of an AER decision.

From 2008 to 2017, network businesses and other parties applied for limited merits review of 33 of the AER's 52 electricity network decisions. Network businesses often succeeded in having their rates of return and revenues increased, whereas consumer representatives and governments were invariably unsuccessful in arguing that network revenues should be decreased.[9]

From 2008 to 2014, Tribunal decisions added $3.2 billion to network revenues. In later decisions, network businesses sought a further $6 billion in revenue above what the AER had determined (box 3.2).

Following the Australian Government's abolition of limited merits review in October 2017, the AER committed to a more collaborative approach to network regulation, driven by customers' best interests (section 3.6). No appeals for judicial review have since been lodged on any AER decisions on network revenue.

9 AER, *Review of the limited merits review framework, AER submission to CoAG Energy Council*, October 2016.

Box 3.2 Legal reviews of AER decisions on NSW and ACT networks

One of the longest running appeal processes (with ongoing ramifications in 2020) related to the Australian Energy Regulator's (AER) revenue decisions in 2015 for five New South Wales (NSW) and Australian Capital Territory (ACT) energy networks. While the Australian Government abolished limited merits review in October 2017, legal processes and their regulatory impacts on those five networks ran for several years.

The decisions covered three NSW electricity distributors (Ausgrid, Endeavour Energy and Essential Energy), the ACT electricity distributor Evoenergy, and NSW gas distributor Jemena Gas Networks. The five businesses sought a review of the AER's decisions, seeking to recover around $5 billion in additional revenue from customers.

The Australian Competition Tribunal in February 2016 found in favour of the network businesses in several areas. In 2017 the Federal Court upheld the Tribunal's findings on some matters, and instructed the AER to remake its five revenue decisions.

The lengthy process posed unique challenges. To manage price uncertainty for energy customers, the AER accepted enforceable undertakings from the five network businesses to limit rises in distribution charges to consumer price index (CPI) changes for the three years to 30 June 2019.

The AER remade its revenue decisions on all five network businesses by January 2019. Following the original decisions, each business had embarked on reforms to reduce its operating costs, without compromising network reliability and security. The AER's remade decisions accounted for the businesses' constructive engagement with their stakeholders—including consumer groups and affected distribution businesses—to reach a common position on key issues. The AER also recognised the proposals provided certainty and price stability to customers, and allowed a timely resolution to an unusually lengthy process.

All final decisions resulted in approved revenues below what had been recovered from customers while the remittals were being finalised. The networks are returning excess revenue to customers through lower charges over the regulatory period, which began in July 2019.

3.6 Refining the regulatory approach

The regulatory framework is not static. Recent reforms include the AER using benchmarking to assess network costs; offering incentives for network efficiency; and rewarding the network businesses for quality engagement with their customers when they are developing revenue proposals.

The AER continues to refine its approach to economic benchmarking in assessing a network's proposed operating expenditure. In 2019, for example, it reviewed alternative approaches to assessing information and communication technology (ICT) expenditure. ICT is increasingly a more integral component of energy services delivery. In its review, the AER assessed whether its existing ICT expenditure assessment tools were fit for purpose.

Another ongoing focus is the quality of network businesses' engagement with their customers and with the AER (section 3.6.2). The AER continues to improve incentive schemes and guidelines—for example, it introduced in 2017 a guideline for demand management incentives (section 3.10.7).

3.6.1 Aligning business and consumer interests

The regulatory process is complex and often adversarial. In this environment, consumers may find it challenging to have their perspectives heard, and to assess whether a network business's proposal reflects their interests. In recent processes, the AER and network businesses have trialled new approaches to improve consumer engagement.

To help consumers engage in the regulatory process, the AER publishes documents—including factsheets that simplify technical language—and holds public forums. The AER's Consumer Challenge Panel also provides a mechanism for consumer perspectives to be properly voiced and considered.

A number of network businesses are experimenting with early engagement models to better reflect consumer interests and perspectives in framing their regulatory proposals. The AER is trialing one such approach—the New Reg—in partnership with Energy Networks Australia and Energy Consumers Australia (box 3.3).[10]

Early engagement offers the potential to expedite the regulatory process, reducing costs for businesses and consumers. In particular, effective consumer consultation can lay the foundations for the AER to accept major elements of a business's revenue proposals. If a business and its customers can agree on key areas, then the AER will put significant weight on a proposal reflecting that consensus.

Many network businesses are increasing their focus on consumer engagement—for example, they may run 'deep dive' workshops before lodging a proposal. Also, the businesses are increasingly looking to maintain open and ongoing dialogue with stakeholders throughout the regulatory period, as opposed to engaging intensively once every five years when a proposal is being considered.

Essential Energy's (NSW) regulatory proposal for the period commencing July 2019 is an example of a well targeted and implemented engagement program. Energy Networks Australia recognised the network's efforts, with Essential Energy winning the 2018 Energy Network Consumer Engagement Award. TasNetworks (Tasmania) and Power and Water (Northern Territory) also undertook comprehensive engagement in developing their most recent regulatory proposals.

While engagement is improving, consumer feedback indicated the processes undertaken by some businesses can improve. Consumer groups argued, for example, that recent processes by Ausgrid (NSW), Endeavour Energy (NSW) and Evoenergy (ACT), would have benefited from more meaningful engagement earlier in the process (such as 'deep dive' workshops) rather than engagement compressed towards the end of the process.

The Consumer Challenge Panel was generally supportive of the quality of engagement by network businesses for three

10 AER, ECA and ENA, *New Reg: towards consumer-centric energy network regulation, A joint initiative of the Australian Energy Regulator, Energy Consumers Australia, and Energy Networks Australia, Directions paper*, March 2018.

Box 3.3 Trialing the New Reg model

The Australian Energy Regulator (AER), along with Energy Consumers Australia and Energy Networks Australia, launched the New Reg joint initiative in June 2017 to explore ways to improve sector engagement and identify opportunities for regulatory innovation. The primary objective of the New Reg process is for consumers (represented by a customer forum) and the network business to agree the revenue proposal reflects consumer perspectives and preferences, before the business lodges the proposal for AER assessment. The vision of the initiative is for energy consumers' priorities and stated preferences to drive, and be seen to drive, energy network businesses' proposals and regulatory outcomes.

AusNet Services was the first network business to trial the new initiative, engaging an independent customer forum to represent the perspectives of its customers. The customer forum negotiated with AusNet Services on aspects of the network's proposal, to reach a number of outcomes. To represent accurately the perspectives of customers, AusNet Services and the customer forum undertook extensive consumer engagement, including interviews, field visits, commissioned research, observations (such as focus groups, deep dives, workshops and public forums) and reviews (of complaints data, guaranteed service level and reliability data, and AusNet Services customer research).[a]

By April 2020 the New Reg trial was in its third stage, following AusNet Services' submission of its revenue proposal and the customer forum's final engagement report to the AER in January 2020.[b] The AER is now assessing AusNet Services' proposal.

The AER engaged farrierswier consultancy to monitor the AusNet Services trial, and the Centre for Efficiency and Productivity Analysis (CEPA) to evaluate it. The evaluation will continue as the AER assesses the network's regulatory proposal.

a AusNet Services Customer Forum, *AusNet Services 2021–2025 electricity distribution price review—customer forum final engagement report*, 31 January 2020.
b AusNet Services Customer Forum, *AusNet Services 2021–2025 electricity distribution price review—customer forum final engagement report*, 31 January 2020; AusNet Services, *Electricity distribution price review 2022 to 2026*, 31 January 2020.

regulatory decisions published by the AER in 2020. It noted SA Power Networks ran a well resourced engagement model that other utilities should consider.[11]

The Panel found engagement from the Queensland businesses—Energex and Ergon Energy—to be responsive, inclusive and transparent.[12] However, it found engagement to be less effective on the structure of tariffs and the impact of its proposal on customer bills. The Panel also noted Ergon Energy did not inform its consumers of the full costs of its proposed safety related investment and the available alternatives. The Queensland Council of Social Service observed the Queensland businesses did not set out a clear rationale for tariff reform.[13]

3.7 Power of Choice reforms

Innovations in network and communication technology—including 'smart' meters, interactive household devices, and energy management and trading platforms—are driving change in energy markets. These innovations allow consumers to access real time information about, and make informed decisions in managing, their energy use. If consumers choose to reduce their energy use voluntarily in peak periods, that behaviour can potentially delay the need for costly network investment.

Power of Choice reforms are being progressively rolled out to unlock the potential benefits of these innovations. The reforms include a market led rollout of smart meters, supported by more cost-reflective network pricing (section 3.7.1), and incentives for demand management as a lower cost alternative to network investment (section 3.10.7).

Improvements in energy storage and renewable generation technology are making it increasingly possible for some customers to go 'off grid'. Stand-alone systems or microgrids—where a community is primarily supplied by local generation with no connection to the main grid—are gaining traction, particularly in regional communities remote from existing networks.

The Australian Energy Market Commission (AEMC) in December 2019 released draft rules to address regulatory and pricing barriers to off-grid arrangements. The application of these rules should make it easier for distribution network providers to offer stand-alone power systems where economically efficient to do so, while maintaining appropriate consumer protections and service standards.[14]

The Distributed Energy Integration Program (DEIP)—a collaboration of government agencies, market authorities, industry and consumer associations—aims to enhance customers' benefits from using distributed energy resources, including benefits from access and pricing reforms.[15]

3.7.1 Tariff structure reforms

Under traditional network tariff (price) structures, households and small businesses are charged the same tariffs regardless of how and when they use energy. Some customers—such as those with air conditioners or solar PV systems—do not pay their full network costs under these structures, while other customers pay more than they should. Tariffs for large customers are typically more cost-reflective.

National Electricity Rule changes that took effect in 2017 require distributors to make their tariffs more cost-reflective, to signal to retailers the cost of their customers' use of the network and investment in distributed energy resources (DER). Retailers are the focus of tariff reform, because they act as the interface with consumers. They package network tariffs with other costs (such as wholesale energy) in their retail price offers, and decide how to reflect the charges in those offers. It is up to the customer to choose a retail offer that suits their needs, whether that be a flat rate retail tariff or a more innovative product.

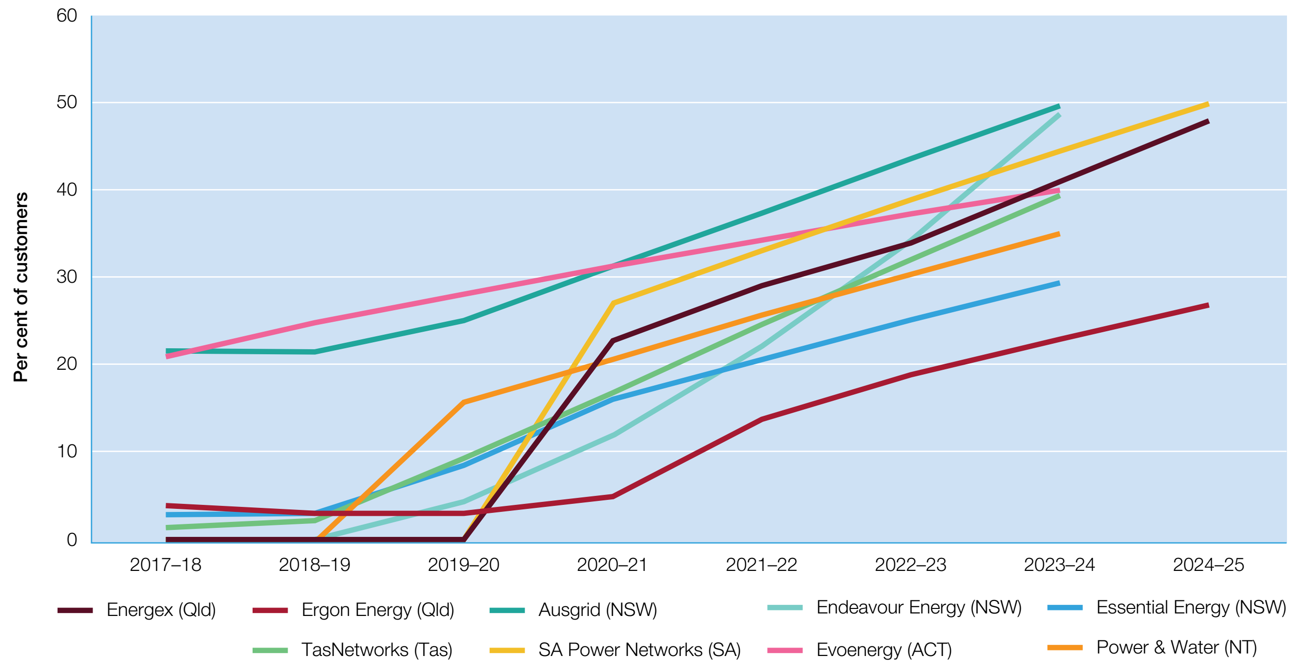
Tariff reform can encourage more efficient use of networks, delay the need for new investment, and reduce the amount of infrastructure that needs to be maintained in the long term. Initially, reform focused on signalling costs during peak demand periods (which historically drove network investment). More recent reform has involved sending price signals to efficiently integrate DER—such as solar PV, batteries and electric vehicles—into distribution networks.

As an example, the AER in 2020 approved SA Power Networks' (South Australia) use of a 'solar sponge' tariff for its residential customers. This tariff offers a lower network charge during the middle of the day when solar output is highest, to encourage shifting of electricity use to those times. Raising demand for grid supplied electricity in the middle of the day can help manage voltage issues and thermal overloads associated with low demand, while shifting demand away from the evening peak that can put heavy strain on the network. SA Power Networks also introduced a demand tariff that offers discounted time-of-use rates and a seasonal peak demand component.[16]

11 CCP14, *Submission on SA Power Networks' revised proposal 2020–25, Revised*, February 2020, p. 7.
12 CCP14, *Submission on Energex's draft decision and revised proposal 2020–25, Revised*, March 2020, p. 14.
13 QCOSS, *Submission on Energex's draft decision and revised proposal 2020–25*, January 2020, p. 1.

14 AEMC, *Updating the regulatory frameworks for distributor-led stand-alone power systems*, December 2019.
15 The DEIP's Access and Pricing Working Group is developing a rule change proposal on the prohibition on export charging, which it expects to submit to the AEMC by mid-2020.

Figure 3.6
Projected assignment of cost-reflective tariffs for residential customers



Source: AER analysis of unpublished forecasts supplied by regulated electricity distribution businesses.

Distribution network businesses are moving towards fully cost-reflective pricing in their second round of tariff structure statements, which the AER considers as part of the revenue determination process. Progress has included:

- simplifying tariff offerings to provide clear, consistent signals
- designing tariffs that more closely reflect how customers' use of the network affects costs
- applying an 'opt-out' or mandatory assignment policy that increases the number of customers whose retailers will face these more cost-reflective tariffs
- integrating network pricing with areas such as network planning and demand management, and trialing alternative approaches.

Initially, distribution network businesses offered cost-reflective structures on an opt-in basis (that is, a retailer or customer had to choose to adopt the new pricing, or would otherwise stay on the old flat price structure). More recently, however, network businesses are moving to an opt-out or mandatory assignment approach, which is expected to widen the use of these tariffs considerably.

Distribution network businesses outside Victoria forecast the proportion of their residential customers assigned to cost-reflective network tariffs will increase from 2020 (figure 3.6).

The limited uptake of smart meters for residential and small business customers has been a barrier to cost-reflective network tariffs being implemented in distribution networks outside Victoria. Smart meters, which measure electricity use in half hour blocks, are essential for cost-reflective tariffs to be applied.

Victoria was the first jurisdiction to progress metering reforms, with its electricity distribution businesses rolling out smart meters from 2009 to 2014. Around 98 per cent of small customers in Victoria have a smart meter.

In other jurisdictions, the rollout of smart meters is occurring on a market led basis, following National Electricity Rule changes that applied from December 2017. All new and replacement meters installed for residential and small businesses consumers must now be smart meters, and

16 SA Power Networks, *2020–25 regulatory proposal, Attachment 17—tariff structure statement*, January 2019.

other customers can negotiate for a smart meter as part of their electricity retail offer.

The new rules also transferred responsibility for metering from distribution network businesses to retailers. The transition to retailer responsibility coincided with large delays in meter installations in some regions. Participants indicated reasons for the delays included poor coordination and data provision among network businesses, retailers and metering coordinators; inadequate retailer systems, processes and controls; and poor resourcing. But from February 2019 new rules required retailers to provide customers with electricity meters within six business days from a property being connected to the network, or with replacement meters within 15 days.[17]

Outside Victoria, Ausgrid (NSW) had the highest penetration of smart or interval meters at February 2020, at 34 per cent of customers. In other networks, 10–15 per cent of customers had a smart or interval meter.[18] This share is expected to increase to a range from 30 per cent for Essential Energy (NSW) and 63 per cent for TasNetworks (Tasmania) by 2025, reflecting the requirement for new meters—including end-of-life replacements—to be smart meters.

3.7.2 Ring-fencing

When a network business offers metering or other services in a contestable market, robust ring-fencing must be in place to ensure the business competes fairly with other providers. The AER publishes a ring-fencing guideline that requires distribution networks to separate their regulated network services (and the costs and revenues associated with them) from unregulated services such as metering, and solar PV and battery installations. Unregulated services must be offered through a separate entity.

The ring-fencing rules aim to ensure network businesses do not use revenue from regulated services to cross-subsidise their unregulated products. They also deter discrimination in favour of affiliate businesses.[19]

All distribution network businesses are required to comply with the AER's guideline and annually report on their compliance to the AER. The AER observed a number of serious breaches in 2017–18, but found fewer compliance issues and breaches in 2018–19.

A number of distributors have worked effectively to remediate breaches, and strengthen systems and processes to support compliance. But compliance could still be improved in a number of areas, particularly in separating staff between the distributor and its affiliates, protecting confidential electricity information about the network, and ensuring any shared costs are appropriately allocated between the distributor and an affiliate. However, when breaches have occurred, distributors have mostly communicated promptly with the AER, acted quickly to contain any potential harms from those breaches, and put in place plans to prevent breaches from recurring.

In 2019 the AER reviewed the ring-fencing guideline to strengthen some obligations, and to simplify compliance. The new guideline is scheduled to take effect from July 2020. Civil penalties introduced in February 2020 should help to encourage improved compliance.

3.8 Network revenue

Since 2006 revenues earned by network businesses have shown two distinct trends—rapid growth for several years (until around 2013 in transmission and 2015 in distribution), followed by a significant downturn. The revenue downturn was more gradual for transmission network businesses than for distribution (figures 3.7 and 3.8).

Key revenue drivers between 2006 and 2019 included:

- the value of network assets (the RAB), on which revenues are paid each year to cover depreciation and finance costs. New investment adds to the asset base each year (resulting in higher depreciation and finance costs). Surging investment from 2006 to 2013 led the network industry's asset base to rise by 62 per cent. Investment then weakened, but the impact of past over-investment remains in the asset base (section 3.10).
- the rate of return paid to network owners and lenders, which finance the business's operations. Rates of return peaked at over 10 per cent from 2009 to 2013, but by 2020 had eased to around half that level (section 3.11).

Operating, maintenance and other costs correlate less closely with market conditions than do other revenue drivers, and show relatively stable trends. These costs in 2009 were about one third the size of asset investment, but by 2015 weakening investment resulted in the two being at comparable levels. Operating expenditure later eased, as network businesses (especially distributors) implemented efficiency programs (section 3.12).

17 AEMC, *Rule determination: National Energy Retail Amendment (Metering Installation Timeframes) Rule 2018*, December 2018.
18 Estimates based on AER market intelligence.
19 The ring-fencing reforms apply to demand management incentives too (section 3.10.7).

Figure 3.7
Transmission revenue and key drivers

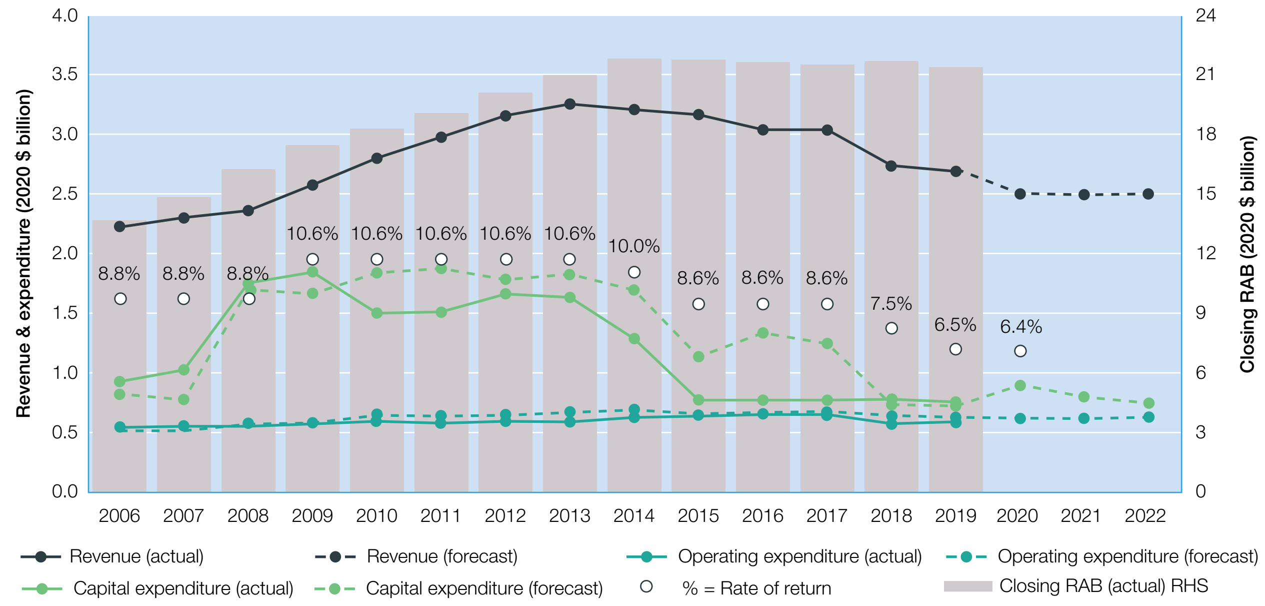
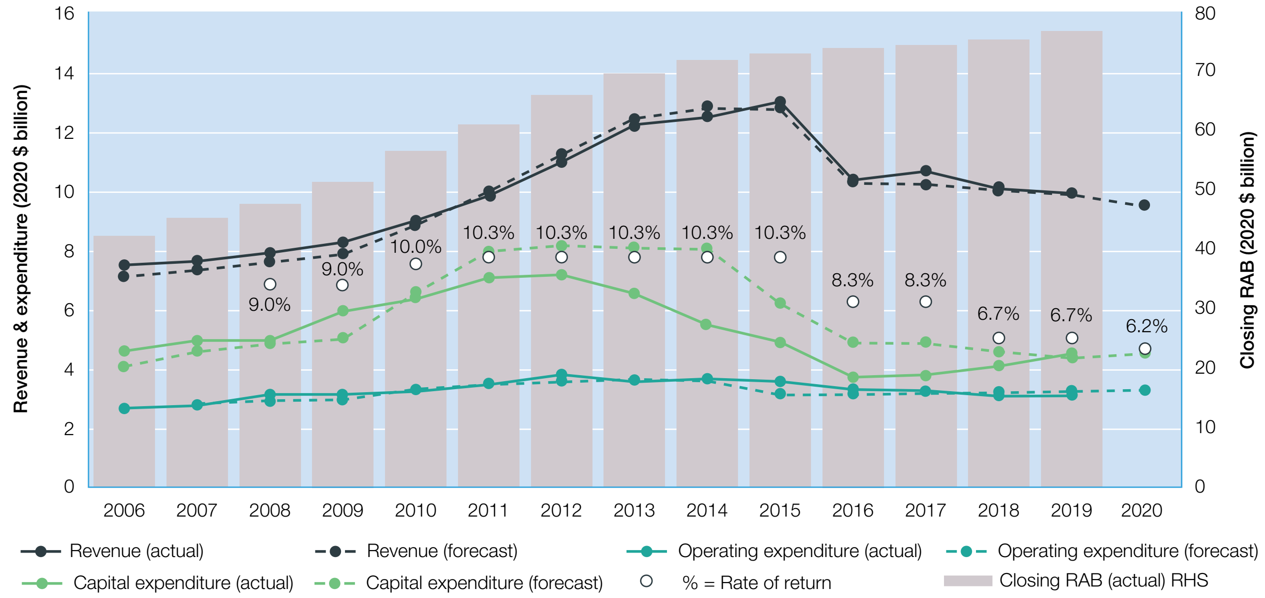


Figure 3.8
Distribution revenue and key drivers



RAB, regulatory asset base.

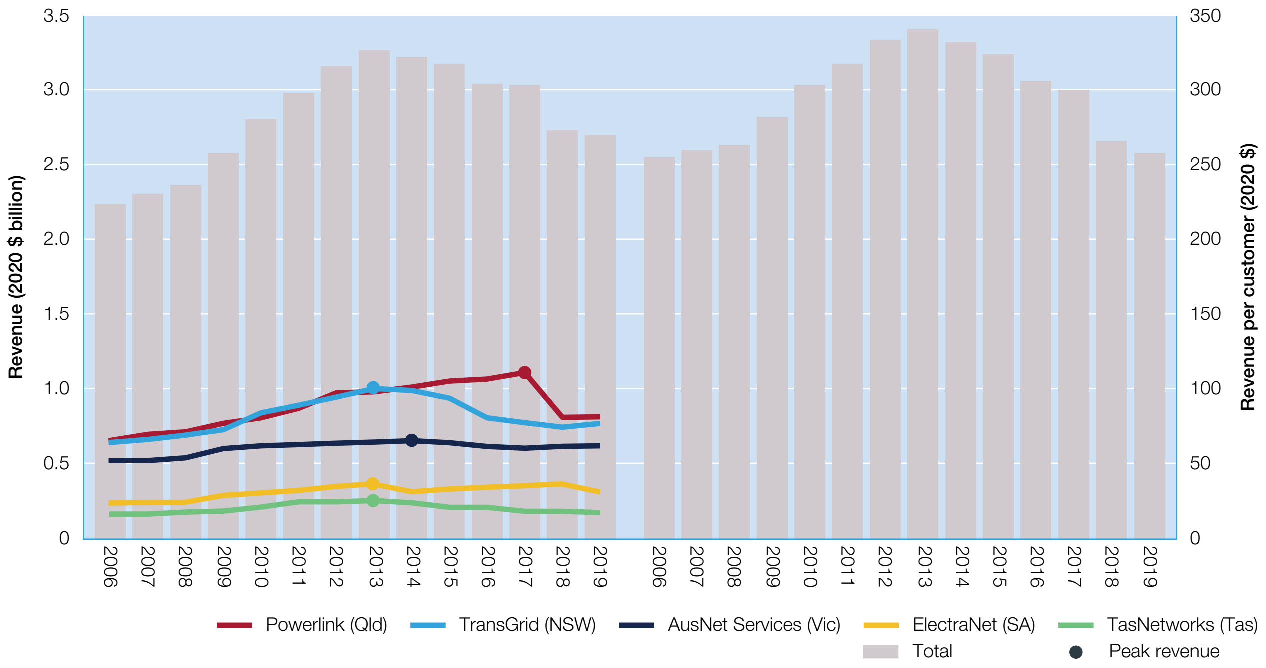
Note (figures 3.7 and 3.8): Most network businesses report on a 1 July – 30 June basis. The exceptions are Victorian networks: AusNet Services (transmission) reports on a 1 April – 31 March basis, and the Victorian distribution network businesses report on a 1 January – 31 December basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

All data are consumer price index (CPI) adjusted to June 2020 dollars. Rates of return are weighted average cost of capital (WACC) forecasts in AER revenue decisions and Australian Competition Tribunal decisions. The rates of return shown represent the highest rate that applied to network businesses each year.

Operating expenditure methodology for transmission network businesses has changed since 2018. Forecast transmission revenues are subject to adjustments over which the AER has limited visibility.

Source: Closing RAB: AER modeling; revenue: economic benchmarking regulatory information notice (RIN) responses; capital expenditure: AER modeling, category analysis RIN responses; operating expenditure: AER modeling, economic benchmarking RIN responses.

Figure 3.9
Transmission network revenue



Note: Actual outcomes, CPI adjusted to June 2020 dollars. Most transmission network businesses report on a 1 July – 30 June basis. The exception is AusNet Services (Victoria) which reports on a 1 April – 31 March basis. The data show the outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Transmission networks do not report customer numbers. Per customer metrics for the transmission network were calculated using the total number of distribution customers.

Source: Economic benchmarking regulatory information notice (RIN) responses.

The AER forecasts network revenue and investment will plateau between 2020 and 2022, although continuing distribution investment will likely further raise the industry RAB over this period.

3.8.1 Long term revenue trends

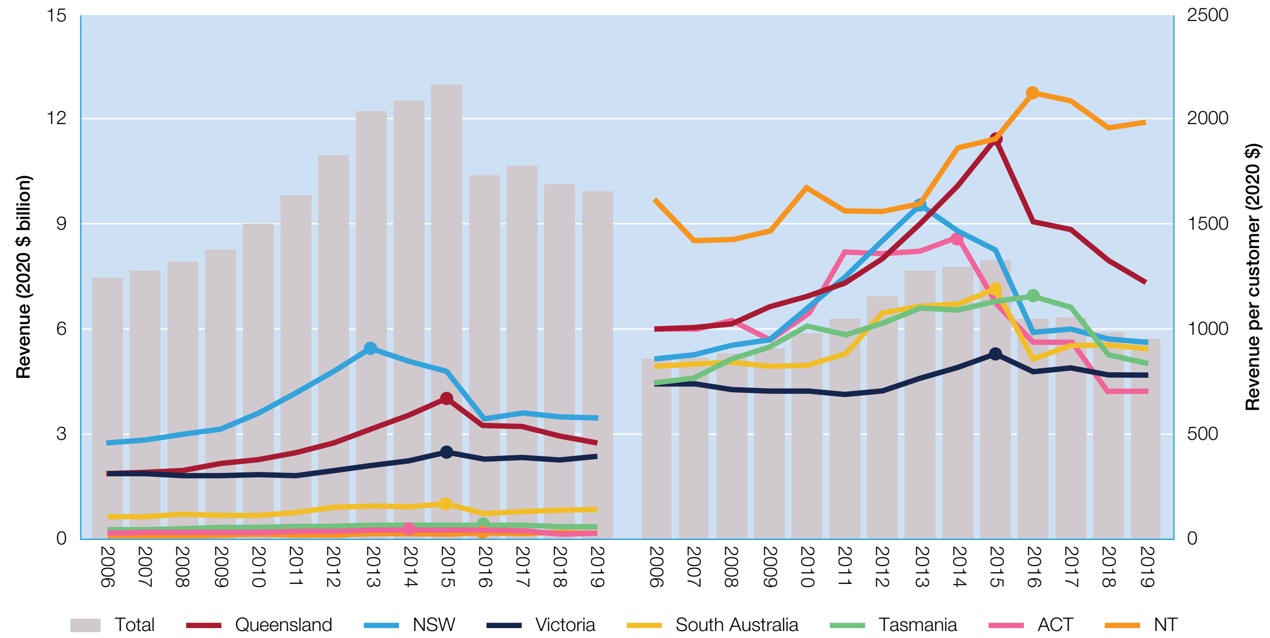
Network revenues rose each year from 2006 to 2015 by an average 7 per cent. Figures 3.9 and 3.10 chart transmission and distribution revenue from 2006 to 2019. With network charges absorbing around 43 per cent of retail customer bills, this growth led to escalating retail electricity bills over the period.

A 62 per cent increase in the value of the RAB (caused by surging investment) was a key contributor. The ballooning asset base increased financing costs and depreciation charges, resulting in higher revenue allowances to cover these costs. Rising interest rates due to the global financial crisis compounded the impact on revenue. Operating expenditure also increased every year from 2006 to 2012, by an average 7 per cent, further boosting network revenue. Further, many AER decisions faced legal challenges over this period, often resulting in court decisions that increased network revenue (box 3.2).

Revenue rose higher in Queensland and NSW than elsewhere. In Queensland, it more than doubled between 2006 and 2015; in NSW, it rose by 90 per cent from 2006 to 2013. Revenue growth was less dramatic in Victoria, at 32 per cent from 2006 to 2015. A key cost driver in Queensland and NSW was the stricter reliability standards imposed by state governments, which required new investment and operating expenditure to meet the new standards.

Cost pressures began to ease when electricity demand from the grid plateaued, causing new investment to scale back from 2013. This easing stemmed several years of rapid growth in network assets and their associated depreciation and finance costs. The changing demand outlook coincided with government moves to allow network businesses greater flexibility in meeting reliability requirements.

Figure 3.10
Distribution network revenue, by region



Note: Actual outcomes, CPI adjusted to June 2020 dollars. Victorian distribution network businesses report on a 1 January – 31 December basis. All other distribution network businesses report on a 1 July – 30 June basis. The data show the outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: Annual reporting regulatory information notice (RIN) responses; economic benchmarking RIN responses; regulatory accounts.

The financial environment also improved after 2012, easing borrowing and equity costs. After peaking at over 10 per cent between 2009 and 2013, rates of return approved for some network businesses were below 5 per cent in 2020.

Energy rule reforms phased in from 2015 also helped stem growth in network revenue. The reforms, which explicitly linked network costs to efficiency factors, encouraged network businesses to better control their operating costs.

In combination, these factors reduced the revenue needs of network businesses. But the five year regulatory cycle meant lower investment and rates of return often lowered revenue only after a significant lag. More generally, consumers will continue to pay for the over-investment in network assets from 2006 to 2013 for the economic lives of those assets, which may be up to 50 years. The Grattan Institute called for the asset bases of some networks to be written down so consumers do not pay for that over-investment.[20] The Australian Competition and Consumer Commission (ACCC) supported this position, particularly for government owned networks in Queensland, NSW and Tasmania.[21]

Consumer groups and some industry observers remain concerned the regulatory framework enables network businesses to earn excessive profits. In response to calls for greater transparency around the actual returns earned by the network businesses, the AER in 2018 began publishing information on the businesses' profitability. From 2020 the AER will expand its coverage of profitability indicators.[22] This initiative will help stakeholders make more informed assessments of the returns earned by each network business.

Table 3.4 summarises recent financial indicators for distribution networks on a per customer basis, to allow comparability across networks.[23]

20 Grattan Institute, *Down to the wire—a sustainable electricity network for Australia*, March 2018.

21 ACCC, *Retail Electricity Pricing Inquiry—final report*, June 2018

22 AER, *Profitability measures for electricity and gas network businesses, Final position paper*, December 2019.

23 Per customer metrics allow for easier comparison of network businesses of different sizes. But multiple factors other than customer numbers—such as line length and terrain—have an impact on these indicators.

Table 3.4 Electricity distribution networks—financial indicators

NETWORK	CUSTOMER NUMBERS[1]	CUSTOMER DENSITY (CUST/KM)	DOLLARS PER CUSTOMER[1] REVENUE[2]	OPERATING EXPENDITURE[2]	CAPITAL EXPENDITURE[2]	ASSET BASE[2]	RATE OF RETURN (%)[3]
QUEENSLAND							
Energex	1 496 317	27.3	951	241	316	8 496	6.0
Ergon Energy	765 924	5.0	1 756	525	715	14 815	6.0
NSW AND ACT							
Ausgrid	1 746 274	41.6	881	262	472	9 145	6.4
Endeavour Energy	1 027 586	26.8	872	249	398	6 468	6.7
Essential Energy	916 471	4.8	1 110	451	537	9 006	6.4
Evoenergy	198 432	36.5	701	285	371	4 085	6.2
VICTORIA[2]							
AusNet Services	762 382	16.8	887	275	521	5 793	6.2
CitiPower	345 009	75.7	884	232	357	5 562	5.9
Jemena	354 452	53.5	744	252	353	4 154	6.2
Powercor	853 771	11.3	784	270	429	4 866	5.9
United Energy	697 594	52.0	631	164	235	3 373	6.2
SOUTH AUSTRALIA							
SA Power Networks	906 198	10.1	913	300	416	4 759	6.1
TASMANIA							
TasNetworks	290 446	12.7	840	277	369	6 210	6.0
NORTHERN TERRITORY							
Power and Water[4]	85 743	12.1	1 985	1 067	506	11 426	4.2
TOTAL	10 446 598	13.9	947	297	433	7 385	

1. In 2019 residential customers (a customer who purchases energy principally for personal, household or domestic use) accounted for 88 per cent of total customers on the distribution network. Of the remaining customers, 11 per cent were non-residential (including high voltage customers who were connected at higher than 415 volts, and low voltage customers who were connected at 240 or 415 volts), and 1 per cent were unmetered or 'other'. While these proportions differed across network businesses—91 per cent residential for Energex (Queensland) and 83 per cent for Essential Energy (NSW), for example—the differences did not materially affect the 'per customer' metric.
2. Revenue, capital expenditure, operating expenditure and asset base are actual outcomes for the regulatory year ending in 2019. Distribution networks businesses report on a financial year basis (to 30 June), except in Victoria, where they report on calendar year basis.
3. Rate of return is the nominal vanilla rate for 2019. The rate is updated annually to reflect changes in debt costs.
4. For regulatory purposes, Northern Territory transmission assets are treated as part of the distribution system.

Source: AER estimates derived from economic benchmarking regulatory information notice (RIN) responses; AER modeling; AER revenue decisions; Australian Competition Tribunal decisions.

3.8.2 Recent revenue outcomes

Energy network businesses earned a total of $12.6 billion ($1211 per customer) in 2019:

- Distribution network businesses earned around 79 per cent of all network revenue. They earned just under $10 billion ($953 per customer) in revenue in 2019, which was 2 per cent lower than the previous year, and 23 per cent lower than the revenue peak of $13 billion ($1324 per customer) in 2015 (figure 3.10).
- Transmission network businesses earned around 21 per cent of all network revenue. They earned $2.7 billion ($258 per customer) in revenue in 2019, which was 1 per cent lower than the previous year, and 17 per cent lower than the revenue peak of $3.3 billion (or $340 per customer) in 2013 (figure 3.9).

Current AER decisions

Transmission network revenues are forecast to be around 15 per cent lower on average in current regulatory periods compared with previous periods. Distribution network revenues are forecast to be around 13 per cent lower on average in current regulatory periods compared with previous periods (figure 3.11).[24]

Victoria's distribution networks differ from the general industry trend, with revenues in the current period forecast at 7–12 per cent *higher* than in the previous period, due to forecast increases in operating costs and replacement expenditure (sections 3.10 and 3.12). The current Victorian distribution determinations were made in May 2016.

24 The current regulatory period is the period in place at 1 July 2020.

The AER in early 2020 was consulting on the Victorian distribution networks' revenue proposals for the regulatory period commencing January 2021.[25]

3.9 Network charges and retail bills

Electricity network charges made up around 43 per cent of a residential customer's energy bill in 2018–19 (figure 6.2 in chapter 6). The bulk of these charges relate to distribution network costs.

Declining network revenue since 2015, combined with rising customer numbers, has translated into lower network charges in retail energy bills for most customers (figure 3.12). This lowering of network charges is helping to mitigate some of the recent pressure (caused by higher wholesale electricity costs) on retail energy bills.

Current AER distribution decisions reduced residential energy bills by an average 0.6 per cent across all states and territories. Changes to network charges mostly arise in the first year of a regulatory period, and range from a 9.1 per cent reduction for Power and Water (Northern Territory) to a 0.2 per cent increase for Essential Energy (NSW). This initial change is generally followed by stable prices or modest increases in later years.

The reduction in network charges reflects factors such as lower finance costs, lower demand for electricity (so less need for new investment), operating efficiencies implemented by network businesses (partly in response to AER incentive schemes), and regulatory refinements such as the AER's wider use of benchmarking to assess efficient costs.

Current AER *transmission* decisions reduced network charges in Queensland, but allowed increases in NSW, Victoria, South Australia and Tasmania.

3.10 Electricity network investment

Electricity network businesses invest in capital equipment such as poles, wires and other infrastructure needed to transport electricity to customers. Investment drivers vary among networks, and depend on a network's age and technology, load characteristics, the demand for new connections, and reliability and safety requirements. Substantial investment is needed to replace old equipment as it wears out or becomes technically obsolete. Other investments may be made to augment (expand) a network's capability in response to changes in electricity demand.

25 The Victorian Government indicated its intention to align with the other NEM states, and operate on a financial (rather than calendar) year basis. This change is intended to come into effect for the 1 July 2021 to 30 June 2026 regulatory period. It will mean extending the current regulatory period by six months.

3.10.1 Investment and the regulatory asset base

As part of the revenue determination process, the AER forecasts a network business's efficient investment requirements over the upcoming regulatory period. Efficient investment approved by the AER gets added to the RAB, while depreciation of existing assets gets deducted.

A network's asset base will grow over time if approved new investment exceeds depreciation. The regulated network industry's aggregate RAB grew each year from 2006 to 2019. As the RAB grows, the returns paid to shareholders and lenders that fund those assets also grow. This cost is passed on to customers. Given some network assets have a life of up to 50 years, network investment will impact retail energy bills long after the investment is made.

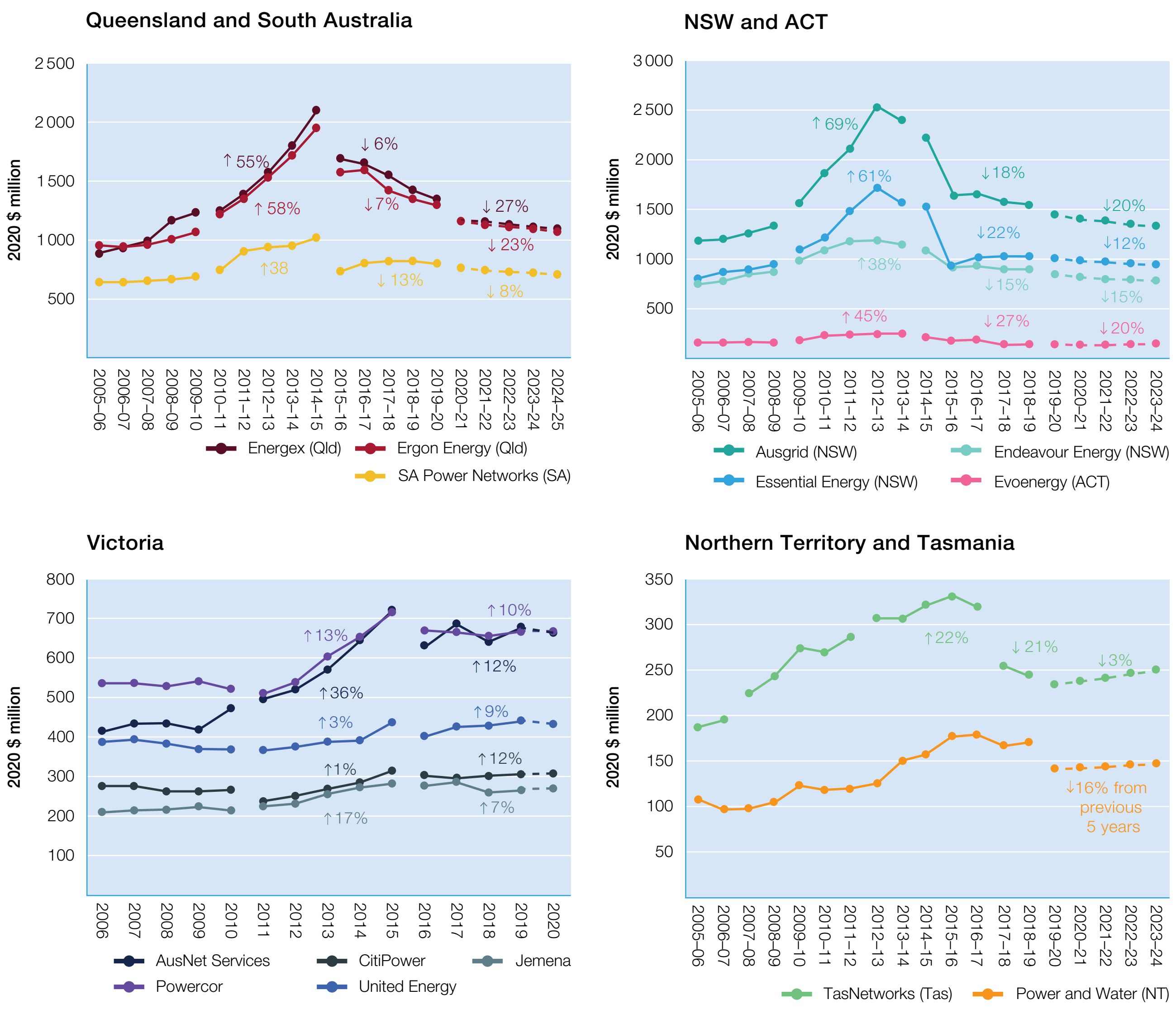
Network businesses receive a guaranteed return on their RAB. For this reason, they have an incentive to over-invest if their allowed rate of return exceeds their actual financing costs. Previous versions of the energy rules enabled significant over-investment in network assets, which partly drove the sharp rise in network revenue from 2006 to 2015 (section 3.10.2). Under reforms introduced in 2015, the AER can remove inefficient investment from a network's asset base if the network overspent its allowance, to ensure customers do not pay for it.

In 2015 the AER also launched new incentives for network businesses to keep their capital expenditure within approved forecasts (box 3.4).

3.10.2 Historical investment trends

Network investment grew by an average of 8 per cent per year from 2006 until it peaked at $8.9 billion in 2012 (figure 3.13). From 2006 to 2009, actual investment was 11 per cent above the approved forecast level. This growth responded to concerns at the time that investment was not keeping pace with high projected growth in electricity demand. More stringent reliability standards imposed by some state governments also spurred higher investment.

Figure 3.11
Distribution network revenue, by network business



Note: Percentage values reflect growth from the previous regulatory period. Dollar values are CPI adjusted to June 2020 dollars.

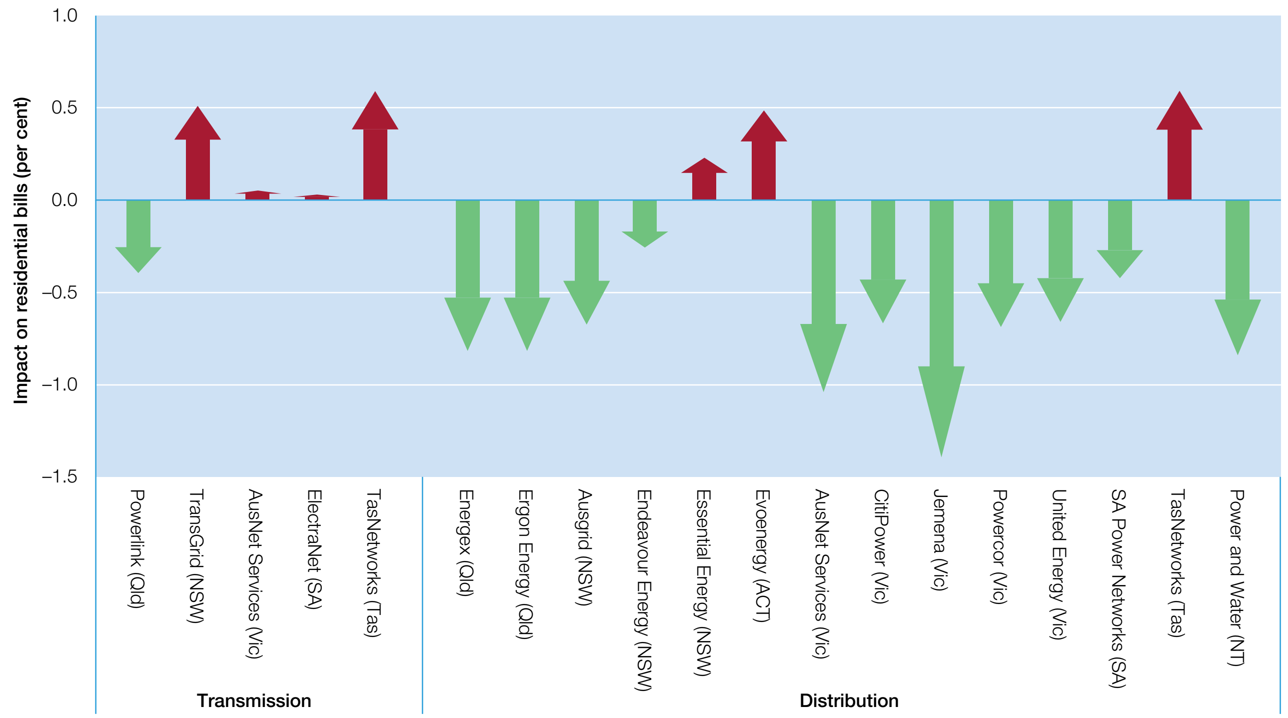
Assumptions are set out in figure 3.8 notes.

Source: AER regulatory decisions; annual reporting regulatory information notice (RIN) responses; economic benchmarking RIN responses; regulatory accounts.

But lower demand for electricity began to reverse this trend from 2013. Many projects were postponed or abandoned when it became clear that earlier projections of sustained demand growth would not eventuate. Further, a shift in government policy towards less stringent reliability obligations on network businesses made some projects redundant, leading to several proposals being scaled back or deferred. Network businesses underspent on capital projects (compared with approved AER forecasts) by $12.9 billion (18 per cent) between 2010 and 2018.

Investment levels further eased from 2015 when AER reforms protecting consumers from funding inefficient network projects began. Plus, a capital expenditure sharing scheme (CESS) offered financial incentives for network businesses to avoid investment above forecast levels. In 2019 network businesses overspent on capital projects by

Figure 3.12
How AER decisions affect residential customer bills



Note: Estimated impact of latest AER decision on the network component of a residential electricity bill, based on AER estimates of retail electricity prices and typical residential consumption in each network. Revenue impacts are nominal and averaged over the life of the current decision.

The data account for changes in only network charges, not changes in other bill components. Outcomes will vary among customers, depending on energy use and network tariff structures.

Source: AER revenue decisions; additional AER modeling.

Box 3.4 Capital expenditure sharing scheme

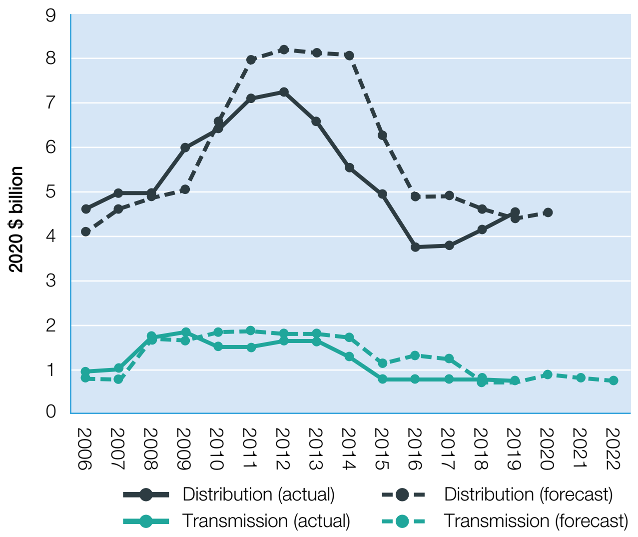
The Australian Energy Regulator's (AER) capital expenditure sharing scheme (CESS) creates an incentive for network businesses to keep new investment within forecast levels approved in their regulatory determination. The CESS rewards efficiency savings (spending below forecast) and penalises efficiency losses (spending above forecast).

The CESS allows a network business to retain underspending against the forecast for the duration of the current regulatory period (which may be up to five years, depending on when the spending occurs). In the following regulatory period, the network business must pass on 70 per cent of underspends to its customers as lower network charges. The business retains the remaining 30 per cent of the efficiency savings.

After the regulatory period, the AER conducts an ex-post review of the network's spending. Approved capital expenditure is added to the regulatory asset base (RAB). However, if a network business overspends its capital allowance, and the AER finds the overspending was inefficient, then the excess spending may not be added to the RAB. Instead, the business bears the cost by taking a cut in profits. This condition protects consumers from funding inefficient expenditure.

The scheme poses risks that businesses may inflate their original investment forecasts. To manage this risk, the AER assesses whether proposed investments are efficient at the time of each reset. Another risk is that the scheme may incentivise a network business to earn bonuses by deferring critical investment needed to maintain network safety and reliability. To manage this risk, the CESS is balanced by separate incentives that focus on efficient operating expenditure (box 3.5) and service quality (box 3.6). This balancing of schemes encourages network businesses to make efficient decisions on their mix of expenditure so as to provide reliable services in ways that customers value (section 3.14.1).

Figure 3.13
Network investment



Note: Actual outcomes, CPI adjusted to June 2020 dollars. Most network businesses report on a 1 July – 30 June basis. The exceptions are Victorian networks: AusNet Services (transmission) reports on a 1 April – 31 March basis, and the Victorian distribution network businesses report on a 1 January – 31 December basis. 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 modeling; annual reporting regulatory information notice (RIN) responses.

3 per cent (compared with approved AER forecasts). It was the first year of overspending since 2009 (box 3.4).

3.10.3 Recent capital expenditure outcomes

Electricity networks invested $5.3 billion (or $505 per customer) in network assets in 2019, which was an 8 per cent increase (6 per cent per customer) on the previous year's investment. While network investment in 2019 rose for third consecutive year, expenditure was still 41 per cent lower than the $8.9 billion ($937 per customer) invested in 2012 (figures 3.14 and 3.15).

Distribution networks accounted for around 86 per cent of total network investment in 2019:

- Distribution network businesses invested $4.5 billion ($433 per customer) in network assets in 2019, which was a 9 per cent increase (8 per cent per customer) on the previous year's investment but 37 per cent less (43 per cent per customer) than peak investment of $7.2 billion in 2012.
- Transmission network businesses invested $756 million ($72 per customer) in network assets in 2019, which was a 2 per cent decrease (4 per cent per customer) on the previous year's investment and 59 per cent less (64 per cent per customer) than peak investment of $1.8 billion in 2009.

AER decisions in place at 1 July 2020 forecast distribution network investment to be 8 per cent lower on average over the current five year regulatory period compared with the previous period. Transmission investment is forecast to be 15 per cent lower.[26]

Recent AER decisions

Since January 2019 the AER has made eight revenue decisions on electricity distribution networks. All but two of those decisions approved *lower* investment expenditure allowances for distribution network businesses in the current regulatory period than in the previous period. The majority of forecast investment for distribution network businesses is to replace and refurbish old assets.

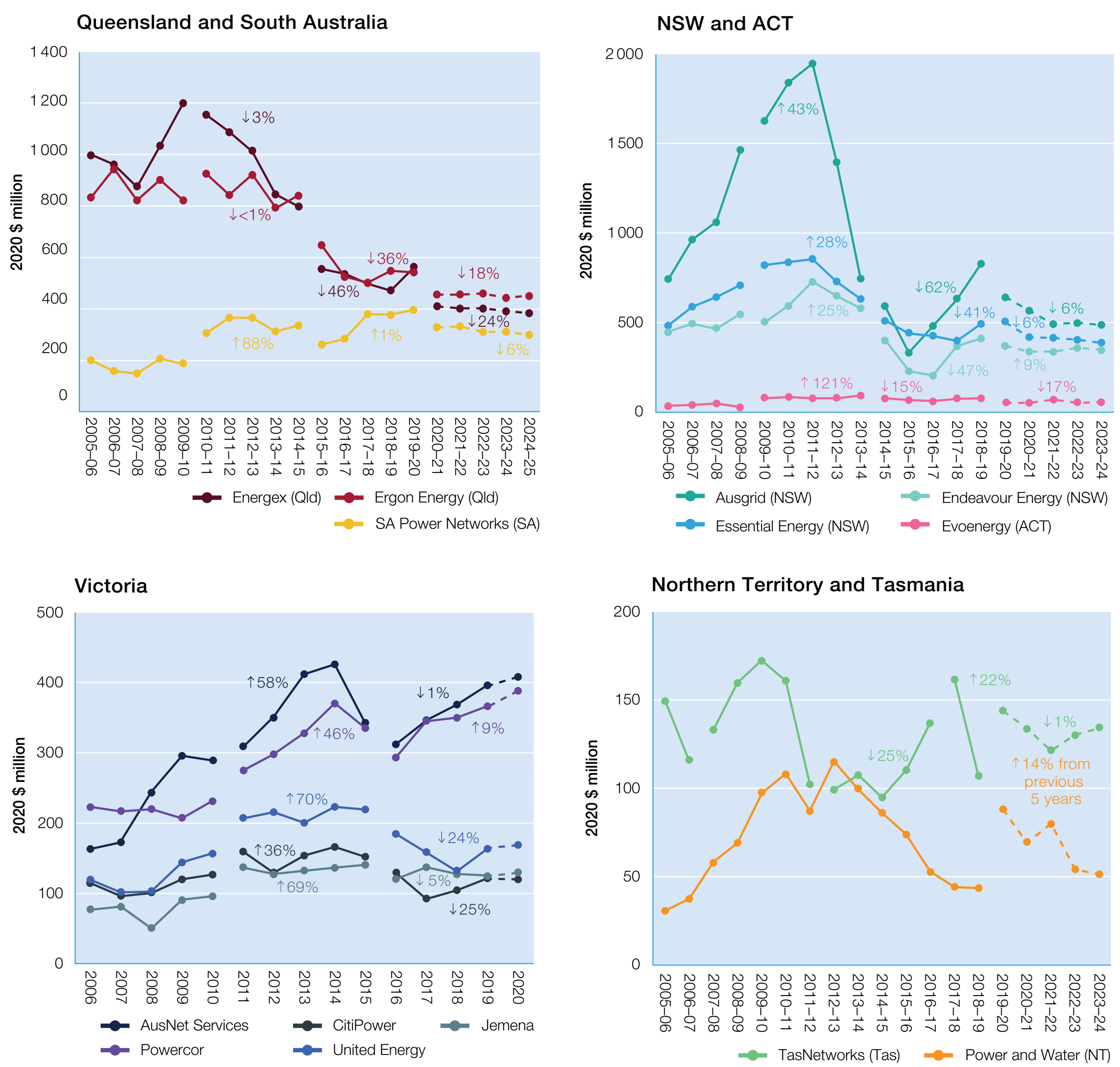
Additionally, in April 2019 the AER made a revenue decision jointly covering Tasmania's transmission and distribution networks, and in June 2020 it made a revenue decision on the NSW–Queensland Directlink interconnector.[27]

For distribution networks in NSW, over the regulatory period commencing July 2019:

- stakeholders—including the AER's Consumer Challenge Panel, the Energy Users Association of Australia, and the Public Interest Advocacy Centre—considered Ausgrid's revised investment proposals to be 'reasonable and supportable'
- Essential Energy's investment was balanced against the costs of past investment needed to meet NSW Government licensing conditions for network security and reliability
- Endeavour Energy's approved investment was 9 per cent higher than in its previous regulatory period, to accommodate growth, replace ageing infrastructure, and invest in technology to transform the business and improve customer service. Endeavour Energy was one of two distribution network businesses—the other being Power and Water (Northern Territory)—granted investment approvals that were higher than spending in the previous period.

26 Excludes AER decisions on transmission interconnectors.
27 Decisions covering several major transmission networks in 2018 are discussed in the 2018 edition of this report.

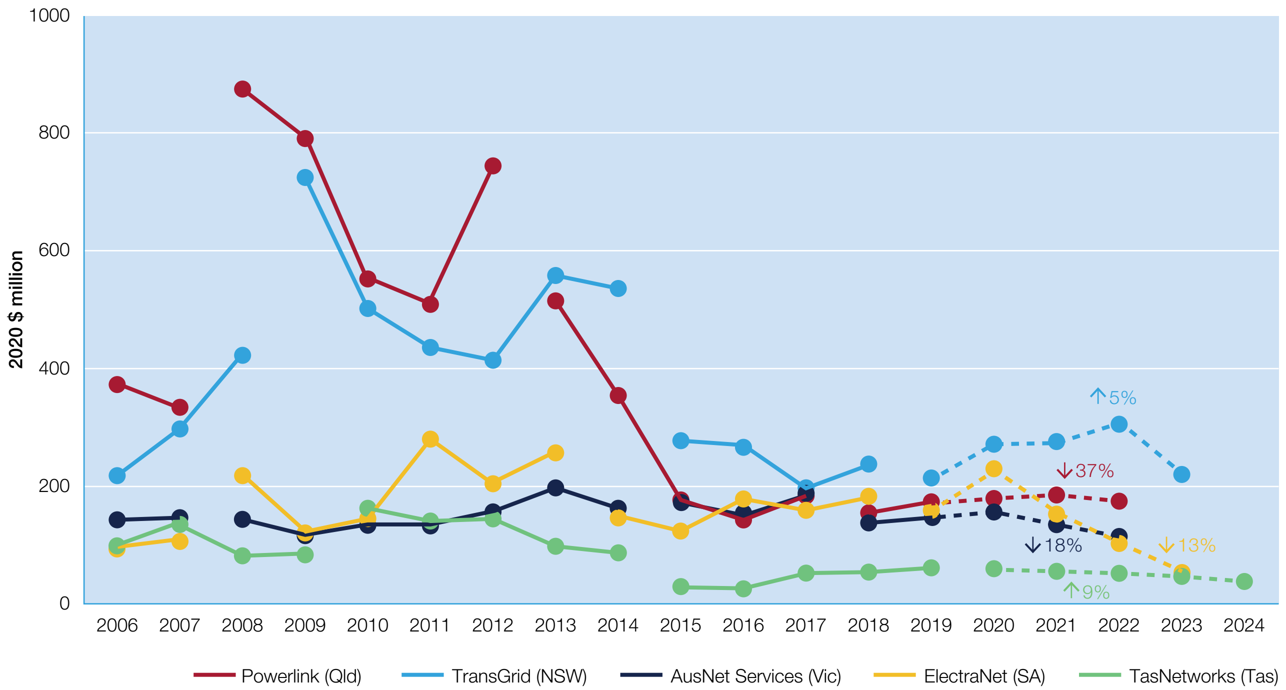
Figure 3.14
Distribution network investment



Note: Percentage values reflect growth from the previous regulatory period. Actual outcomes, CPI adjusted to June 2020 dollars. Assumptions are set out in figure 3.8 notes.

Source: AER modeling; annual reporting regulatory information notice (RIN) responses.

Figure 3.15
Transmission network investment



Note: Actual outcomes, CPI adjusted to June 2020 dollars. Assumptions are set out in figure 3.7 notes. Most transmission network businesses report on a 1 July – 30 June basis. The exception is AusNet Services (Victoria), which reports on a 1 April – 31 March basis. The data show the outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER modeling; annual reporting of regulatory information notice (RIN) responses.

Evoenergy's (ACT) allowance for the regulatory period commencing July 2019 will allow it to manage its ageing asset base to meet safety and reliability standards, accommodate urban developments, and meet the ACT Government's requirements on planning and system security.

In Tasmania, TasNetworks targeted increased investment for the regulatory period commencing July 2019 in assets in poor condition, system security, and the transition to clean energy.[28] The AER scaled back some proposals, but approved capacity that would enable Tasmanian generators to export more electricity to the mainland. It approved three projects (each costing between $278 million and $1 billion) on a 'contingent' basis, requiring trigger events such as the construction of a second interconnector to the mainland to occur.

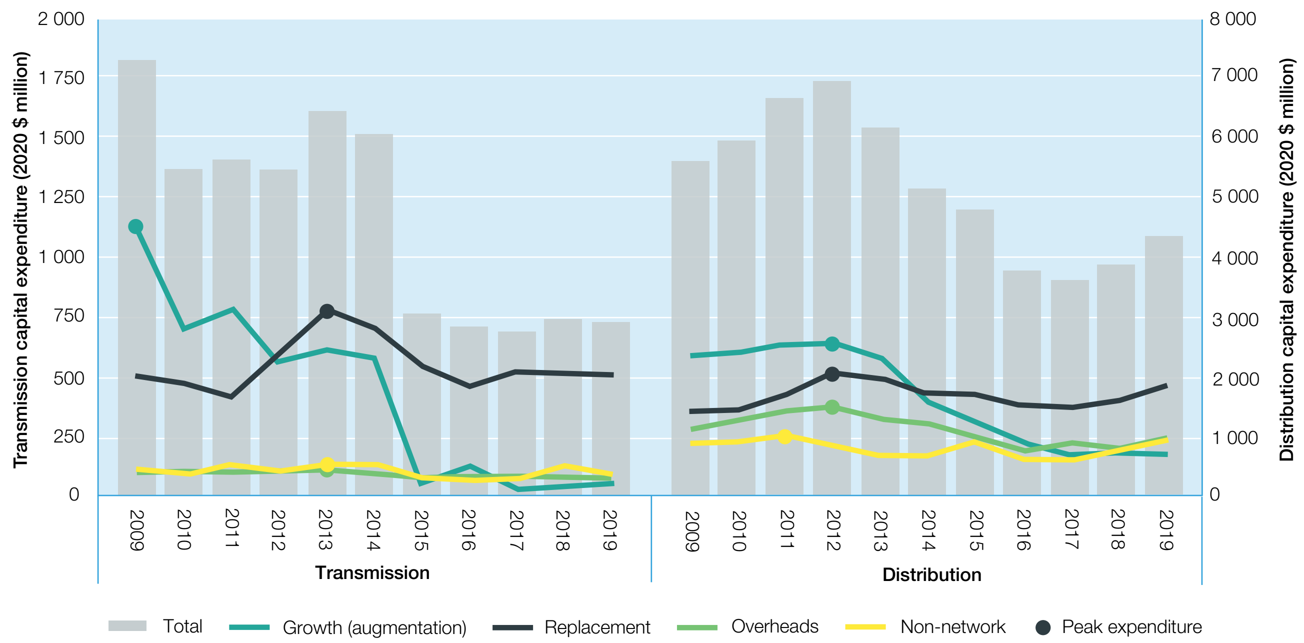
In Queensland, the AER approved less distribution investment for Energex over the regulatory period commencing July 2020 than in the previous regulatory period. Energex consulted widely on its proposal, and provided quantitative cost–benefit analyses for major projects, which allowed the AER to better assess the prudency and efficiency of the proposal. The AER did not accept Ergon Energy's proposed increase in capital expenditure for the same period, finding the business overestimated costs associated with managing risk (particularly those relating to safety). Instead, the AER adopted an approach consistent with its previous decisions, which approved expenditure to address safety risks where the business provides robust evidence of need.

In South Australia, SA Power Networks' investment proposal for the period commencing July 2020 focused on maintaining the network rather than building new infrastructure.[29] The AER did not accept elements of the proposal relating to replacement and property expenditure, and found a lack of stakeholder support for a reliability related augmentation program.

28 The TasNetworks decision jointly covers distribution and transmission investment.

29 SA Power Networks, *2020–25 regulatory proposal, An overview for South Australian electricity customers*, January 2019.

Figure 3.16
Capital expenditure, by driver



Note: Actual outcomes, CPI adjusted to June 2020 dollars. Most network businesses report on a 1 July – 30 June basis. The exceptions are Victorian networks: AusNet Services (transmission) reports on a 1 April – 31 March basis, and the Victorian distribution network businesses report on a 1 January – 31 December basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: Category analysis regulatory information notice (RIN) responses.

In the Northern Territory, the AER accepted Power and Water's revised capital expenditure proposal for the period commencing July 2019. Power and Water identified new methods and data that resulted in some adjustments to its replacement expenditure forecast.

3.10.4 Changing composition of investment

Over the past decade, the composition of network investment has changed markedly. Until recently, significant network investment occurred in growth (augmentation) expenditure to support new connections (such as new substations) and expand capacity to cope with forecast rising demand. In 2009, for example, growth expenditure accounted for 62 per cent of transmission investment and 41 per cent of distribution investment.

But weaker demand for electricity, along with less stringent reliability obligations, led many network owners to shelve or delay growth related projects in the following years. By 2019 growth related investment had shrunk to 15 per cent of distribution network investment and 8 per cent for transmission. In dollar terms, growth investment declined from $3.5 billion in 2009 to $732 million in 2019 (figure 3.16).

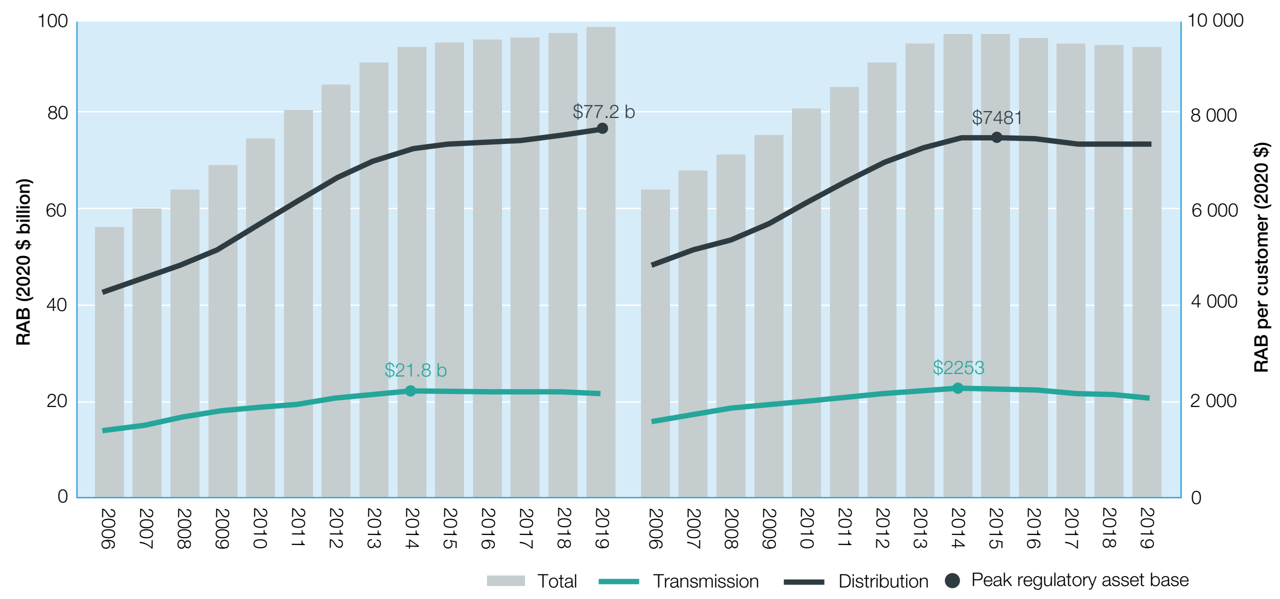
In contrast, over the same time period, replacement expenditure on ageing or degraded assets remained fairly constant at $1.9–2.7 billion. But, as a proportion of shrinking total investment, replacement investment rose strongly. In distribution, replacement investment rose from 24 per cent of total investment in 2009 to 42 per cent in 2019. In transmission, it rose from 27 per cent to 69 per cent of total investment over the same period.

Since 2018 investment in augmentation has been lower than investment in replacement projects, overheads and non-network assets (for example, ICT, buildings and property, fleet and plant, minor asset tools and equipment, and motor vehicles). In each year from 2009 to 2016, investment in augmentation exceeded expenditure on overheads and non-network programs/projects.

Impact on the regulatory asset base

Capital investment approved by the AER gets added to a network business's RAB, on which the business earns returns. Escalating investment inflated the industry RAB by

Figure 3.17
Value of network assets



Note: Closing regulatory asset bases (RABs) for electricity networks in the NEM, CPI adjusted to June 2020 dollars. Most network businesses report on a 1 July – 30 June basis. The exceptions are Victorian networks: AusNet Services (transmission) reports on a 1 April – 31 March basis, and the Victorian distribution network businesses report on a 1 January – 31 December basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Transmission networks do not report customer numbers. Per customer metrics for the transmission network were calculated using the total number of distribution customers.

Source: AER modeling; economic benchmarking regulatory information notice (RIN) responses.

around 8.9 per cent per year over the seven years to 2013. From 2014 to 2019 lower network investment flattened RAB growth to around 1.4 per cent per year.

The industry RAB for distribution networks continues to rise, reaching a peak value of $77.2 billion in 2019. However, a greater proportional increase in the number of customers on the distribution networks meant the RAB per customer in 2019 ($7385) was 0.3 per cent lower than its peak of $7481 per customer in 2016.

But, in transmission, the RAB fell to $21.4 billion in 2019—the fifth consecutive year of decline since its peak in 2014 ($21.8 billion) (figure 3.17).

3.10.5 Regulatory tests for efficient investment

The AER assesses a network business's efficient investment requirements every five years as part of the regulatory process, but it does not approve individual projects. Instead, it administers a cost–benefit test called the regulatory investment test (RIT). A network business must apply the test when considering an investment project. It must evaluate credible alternatives to network investment (such as generation investment or demand response) that might achieve the required outcome at lower cost. The business should select whatever option delivers the highest net economic benefit, considering any relevant legislative obligations. This assessment requires public consultation.

There are separate tests for transmission networks (RIT–T) and distribution networks (RIT–D). The AER publishes guidelines on how to apply the tests,[30] and monitors businesses' compliance with the tests. It also resolves disputes over whether a network business has properly applied a test.

Until 2018 the regulatory tests applied to only growth investment, which until 2014 was the biggest component of network investment. But, with replacement expenditure overtaking growth investment in most networks (section 3.10.4), the test now applies to replacement projects too. Other revisions were made to the test to ensure it

30 AER, *Application guidelines—regulatory investment test for transmission/distribution*, December 2018.

adequately considers system security, emissions reduction goals, and low probability events that would have a high impact.

The AER in December 2018 published the current version of the RIT application guidelines. The review of the preceding guidelines focused on improving guidance for applying RITs under the current regulatory framework. Civil penalties apply to network businesses that do not comply with the RIT requirements (including the required consultation procedures).

The AER is developing new RIT guidelines to make the Australian Energy Market Operator's (AEMO) integrated system plan actionable, as part of broader reforms to strengthen links with transmission planning.[31] Once in place, these guidelines will influence transmission planning by triggering RITs, and replace some elements of the RIT–T process.

The AER began consulting on the changes in November 2019, with a view to having the new guidelines take effect by 30 June 2020.

Recent regulatory test activity

A focus of recent RIT activity has been interconnector projects linking transmission networks in different jurisdictions.

ElectraNet (South Australia) in 2019 conducted a RIT–T for a major network interconnector project linking South Australia with NSW. The project involves a new interconnector between Robertstown in South Australia and Wagga Wagga in NSW, with a spur to Red Cliffs in Victoria. The estimated cost is $1.53 billion (in nominal terms), with completion due between 2022 and 2024.

The South Australian Council of Social Service in 2019 lodged a dispute against ElectraNet's RIT–T process. It claimed ElectraNet did not adequately address system security risks from the retirement of South Australian gas plants. The AER reviewed the dispute and was satisfied with ElectraNet's application of the test.[32]

The AER in January 2020 determined ElectraNet had satisfied the requirements of the RIT–T for the project, and had identified the credible option that maximises economic benefits. ElectraNet and TransGrid (NSW) (the other project proponent) will likely lodge a joint contingent project application to seek regulatory approval of the

31 AER, *Guidelines to make the integrated system plan actionable*, November 2019.
32 AER, *South Australian energy transformation, determination on dispute—application of the regulatory investment test for transmission*, June 2019.

project's efficient costs, to enable the recovery of costs from customers.

The AER in March 2020 also approved the RIT–T for a proposed $230 million capacity upgrade on the Queensland–NSW Interconnector (QNI).[33] The proposal allows more electricity exports from Queensland to NSW, thus avoiding the need for new generation investment in NSW. It also helps manage system security issues and alleviate upward pressure on wholesale electricity prices.

In April 2020 the AER amended TransGrid's revenue determination to allow it to recover the efficient capital costs required to deliver this project. The AER fast tracked its consideration to support the timely completion of this project. TransGrid expects delivery in September 2021 and completion of inter-network testing by June 2022.

In March 2020 the Victorian Government introduced legislation to fast track priority energy projects such as grid scale batteries and electricity transmission upgrades. The legislation allows the government—in consultation with AEMO—to bypass elements of the RIT process.[34] The government indicated it would first apply the fast tracking process to a project that is working to increase capacity on the Victoria–NSW Interconnector.

3.10.6 Annual planning reports

Network businesses must publish annual planning reports identifying new investment that they consider necessary to efficiently deliver network services. The reports identify emerging network pressure points, and options to alleviate those constraints. In making this information publicly available, the reports help non-network providers identify and propose solutions to address network needs.

The AER publishes guidelines and templates to ensure the reports provide practical and consistent information to stakeholders.

33 AER, *Expanding NSW–QLD transmission transfer capacity, Decision*, March 2020.
34 The Hon. Lily D'Ambrosio MP (Victorian Minister for Energy, Environment and Climate Change), 'Victoria acts to secure a more reliable energy system', Media release, 18 February 2020.

3.10.7 Demand management

Distribution network businesses have options to manage demand on their networks to reduce, delay or avoid the need to install or upgrade expensive network assets. Managing demand in this way can reduce upward pressure on network charges. It can also increase the reliability of supply and reduce wholesale electricity costs.

The AER offers incentives for distribution network businesses to find lower cost alternatives to new investment to help cope with changing demands on the network and manage system constraints. The *demand management incentive scheme* (DMIS) incentivises distribution businesses to undertake efficient expenditure on alternatives such as small scale generation and demand response contracts with large network customers (or third party electricity aggregators) to time their electricity use to reduce network constraints. The scheme gives distributors an incentive of up to 50 per cent of their expected demand management costs for projects that bring a net benefit across the electricity market.

Complementing this scheme, the AER operates a *demand management innovation allowance* (DMIA). This is a research and development fund to help distribution businesses develop innovative ways to deliver ongoing reductions in demand or peak demand for network services. An objective of the innovation allowance is to enhance industry knowledge of practical approaches to demand management. Published annual activity reports set out details of projects undertaken by each business. The AER assesses expenditure claims to ensure distribution businesses appropriately use their funding. Any underspent or unapproved spending is returned to customers through revenue adjustments.

Over the two years to 30 June 2019 (31 December 2018 for Victorian distributors),[35] almost $10 million of innovation allowance funding was approved. Figure 3.18 sets out funding by project type. The largest component of funding related to battery storage. Supported projects included:

- Energex (Queensland) installing a commercial battery and solar PV system
- TasNetworks (Tasmania) trialling an aggregation of customer batteries to manage network constraints on Bruny Island
- Endeavour Energy (NSW) trialling an aggregation of residential batteries to manage peak demand, improve power quality and defer capital investment; and installing a grid connected battery for peak shaving, reliability support, and improved quality of supply
- Ausgrid (NSW) running a feasibility study on community batteries.

Other significant funding was allocated to microgrids, air conditioning and pool pump load control projects, and tariff studies. Projects funded in these areas include:

- Ergon Energy and Energex's (Queensland) Centralised Energy Storage System project for a 100 kilowatt energy storage system to encourage customer owned renewable generation and develop microgrid functionality
- Powercor's (Victoria) 'Energy Partner' program, which used air conditioning load control to alleviate peaky load on the network in the Bellarine Peninsula and reduce load at risk
- TasNetworks's (Tasmania) 'emPOWERing You' tariff trial project on how customers respond to new tariff designs.

Research funding covered projects to, for example, laboratory test devices, make algorithms, look into future grid and electric vehicle demand, and fund scholarship studies. Supported projects include Ausgrid's (NSW) Power2U (demand management for replacement needs), which explored the viability of non-network options to manage risk associated with retiring network assets. Other funded projects included studies on the use of energy trading and distributed energy platforms for demand management.

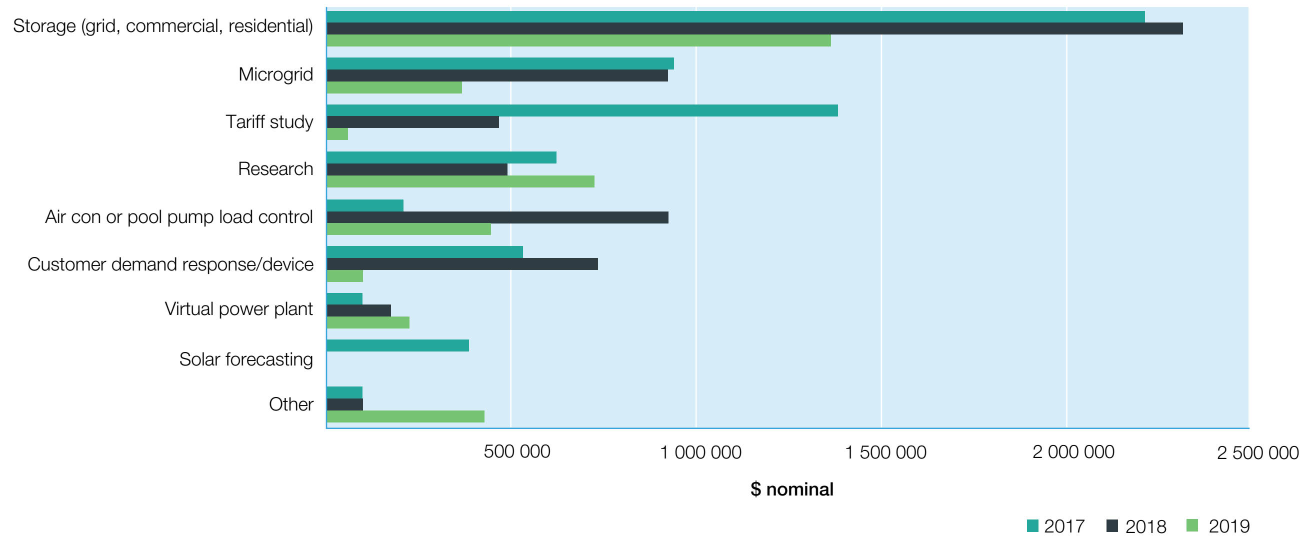
Some network businesses have undertaken demand management projects outside the DMIS and DMIA framework. United Energy's Summer Saver program, for example, targets network areas with highly utilised distribution transformers and low voltage circuits at high risk of overloading during summer months. Customers participating in the program are offered financial rewards to reduce electricity use voluntarily when asked by United Energy. United Energy reported in November 2019 that the program had led to the deferral of more than $10 million in capital expenditure.[36]

In addition to managing network constraints, demand response solutions can help manage wholesale electricity demand during extreme peaks. In September 2019 the University of Technology Sydney published findings on a trial demonstrating how customers can help the grid host rooftop solar power.[37] The joint industry project, partly funded by the Australian Renewable Energy Agency (ARENA),[38] involved the installation of solar PV and energy storage at around 90 sites across three locations to form a virtual power plant. Surplus generation was stored for later use to reduce peak demand on Essential Energy's (NSW) network. The innovation allowance allowed Essential Energy $107 548 in 2017–18 for its cost contribution to this project, and $171 248 in 2018–19.

35 At the time of publishing, the AER had not assessed claims by Victorian distribution businesses for expenditure incurred in 2019.

36 United Energy, *Re: Application for the revised DMIS to start from 1 November 2019*, 7 June 2019.

Figure 3.18
Funding of demand management innovations



Note: Victorian distribution network businesses report on a 1 January – 31 December basis. All other distribution network businesses report on a 1 July – 30 June basis. The data show the outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). 2019 data excludes expenditure incurred by Victorian distribution businesses.

Source: AER, *Approval of Demand Management Innovation Allowance expenditures by distributors*, September 2019; AER, *Approval of Demand Management Innovation Allowance (DMIA) expenditures by non-Victorian electricity distributors in 2018–19*, May 2020.

3.11 Rates of return

The shareholders and lenders that finance a network business expect a commercial return on their investment. The AER sets an allowed rate of return, but a network's actual returns can vary from the allowed rate. The variance can be due to the impact of incentive schemes, forecasting errors, revenue over- or under-recovery under a revenue cap, or smoothing processes, for example.

The AER calculates allowed returns each year by multiplying the RAB by the rate of return set by the AER.[39] Given electricity networks are capital intensive, returns to investors typically make up 30–50 per cent of a network's total revenue allowance.

The rate of return estimates the cost of funds that a network business's financiers require to justify investing in the business. It is a weighted average of the return needed to attract two sources of funding—*equity* (dividends paid to a network business's shareholders) and *debt* (interest paid on borrowings from banks and other lenders). Given this weighting approach, the rate of return is sometimes called the weighted average cost of capital (WACC).

If the AER sets the rate of return too low, then a network business may not be able to attract sufficient funds to invest in assets needed for a reliable power supply. If the rate is set too high, then the network businesses have a greater incentive to over-invest, and consumers will pay for a 'gold plated' network that they do not need.

The rate of return is a significant driver of network revenue and a customer's energy bills. A 1 percentage point increase

37 University of Technology Sydney, *Networks renewed: project results and lessons learnt*, September 2019.

38 Participants included the Institute for Sustainable Futures at the University of Technology Sydney, Essential Energy (NSW), AusNet Services (Victoria), United Energy (Victoria), Reposit Power, the Australian Photovoltaic Institute, and the NSW and Victorian governments.

39 If the rate of return is 5 per cent, and the RAB is $50 billion, for example, then the return to investors is $2.5 billion. This return forms part of a network's revenue needs, and must be paid for by energy customers.

in the rate of return for TransGrid (NSW transmission) would increase the business's revenues by around 10 per cent, for example. For this reason, the rate of return is often a contentious part of a revenue decision.

Conditions in financial markets are a key determinant of the allowed rate of return. AER decisions from 2009 to 2012 took place against a backdrop of the global financial crisis, an uncertain period associated with reduced liquidity in debt markets, and high risk perceptions. Reflecting conditions in financial markets, the rate of return peaked at over 10 per cent in revenue decisions made over this period (figure 3.19). The Australian Competition Tribunal increased some rates of return following appeals by the network businesses.

Borrowing and equity costs have since eased. From 2015 the AER has updated the cost of capital annually to reflect changes in debt costs. More stable financial market conditions resulted in rates of return averaging around 6 per cent from 2016. These lower rates became a key driver of lower network revenues and charges over the past few years (figures 3.7 and 3.8).

3.11.1 Reforms to setting the rate of return

Outcomes from to the AER's approach to setting rates of return were often adversarial before 2018, with many network businesses arguing for a different approach with different parameters. Regulatory decisions were often challenged. These legal battles were long and costly, and added to uncertainty for network businesses, consumers and investors.

New legislation developed by the Council of Australian Governments (CoAG) Energy Council in November 2018 provided for the AER to make its rate of return determinations binding. The AER released its first Rate of Return Instrument (RRI) in December 2018, setting out how it determines the rate of return on capital in revenue determinations.[40]

In setting the rate of return, the AER balances the need for efficient and stable investment against the need to ensure consumers pay no more than necessary for safe and reliable energy. Because customers pay for the network through their electricity bills, the rate of return must be high enough to attract investment in these long term regulated assets, but not so high that it attracts over-investment.

The RRI sets out the approach by which the AER will estimate the rate of return, and includes the return on debt and the return on equity, as well as the value of imputation credits. The RRI is expected to reduce consumer bills by around $30–40 a year on average, relative to the approach set out in the AER's 2013 rate of return guideline.[41]

The first round of regulatory determinations under the RRI were completed in April 2019. The AER is required to review and replace the RRI by December 2022.[42]

3.12 Electricity network operating costs

Electricity network businesses incur operating and maintenance costs that absorb around 35 per cent of their annual revenue (figure 3.3). As part of its five year regulatory review for each network business, the AER sets an allowance for the businesses to recover the *efficient* costs of supplying power to customers. The allowance accounts for forecasts of electricity demand, productivity improvements, changes in input prices, and changes in the regulatory environment. In the first instance, the AER is guided by the forecasts in each business's regulatory proposal. If the AER considers those forecasts are unreasonable, then it may replace them with its own forecasts.

Alongside this assessment, the AER runs an efficiency benefit sharing scheme that encourages network businesses to explore opportunities to lower its operating costs (box 3.5).

3.12.1 Historical operating expenditure trends

Operating costs for distribution networks increased by an average 7.1 per cent each year from 2006 ($2.7 billion, or $306 per customer) to 2012 ($3.8 billion, $403 per customer). From 2013 to 2019 operating costs fell by an average 2.6 per cent per year as distribution network businesses implemented more efficient operating practices.

Operating costs for transmission networks peaked at $649 million ($65 per customer) in 2016, but then fell by an average 3.5 per cent per year to $581 ($56 per customer) in 2019 (figure 3.20).

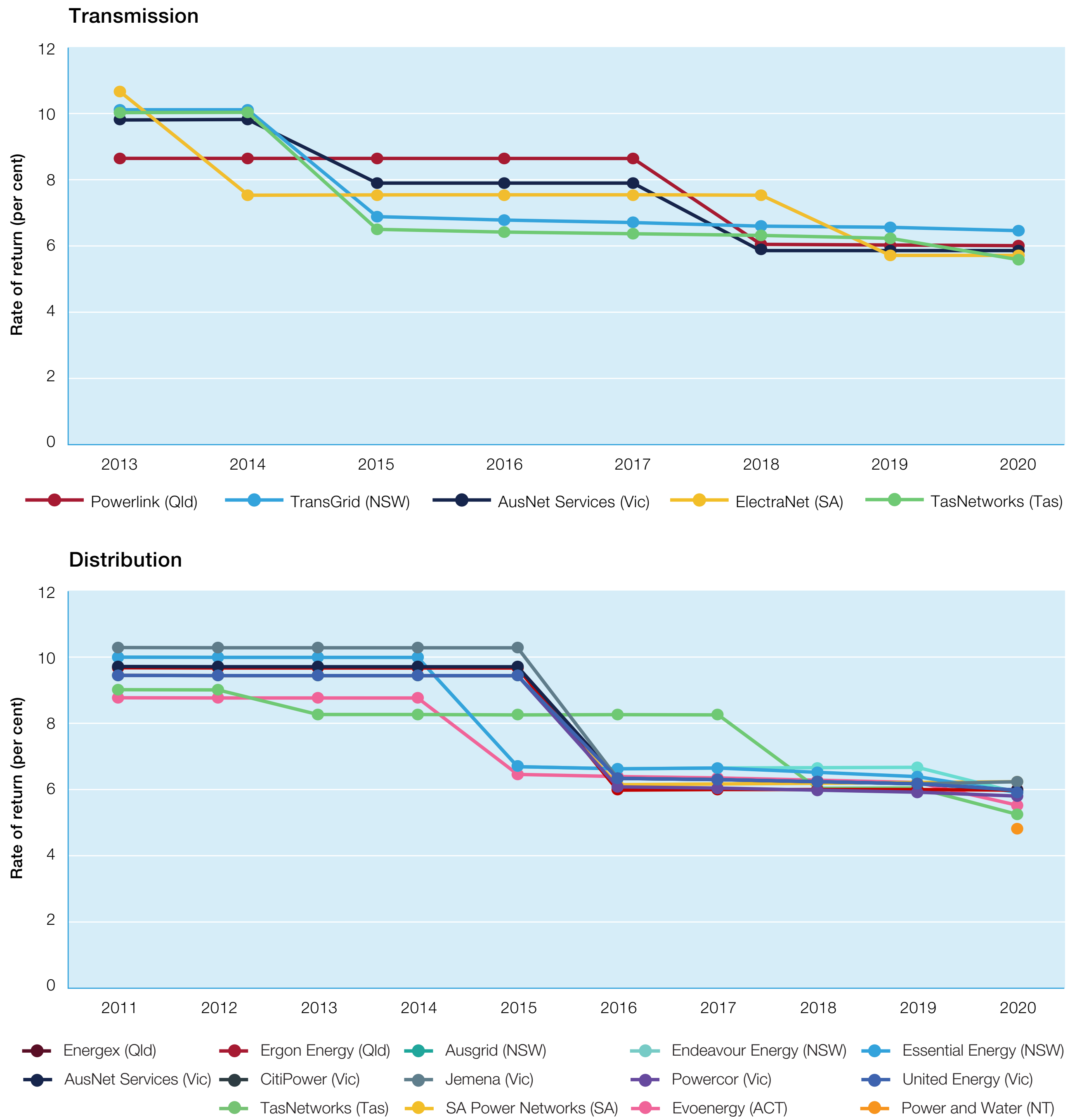
While distribution networks reduced operating expenditure between 2015 and 2019, the reduction was less marked

40 The 2018 RRI specifies the return on debt as a formula, using the trailing average portfolio approach. Network businesses not already applying this method must transition to it over a 10 year period.

41 AER, 'AER releases final decision on rate of return for regulated energy networks', Media release, 17 December 2018.

42 The AER is required to set the RRI every four years.

Figure 3.19
Rates of return for energy networks



Note: Rate of return is the nominal vanilla weighted average cost of capital (WACC).

Source: AER decisions on electricity network revenue proposals; AER decisions following remittals by the Australian Competition Tribunal or Full Federal Court.

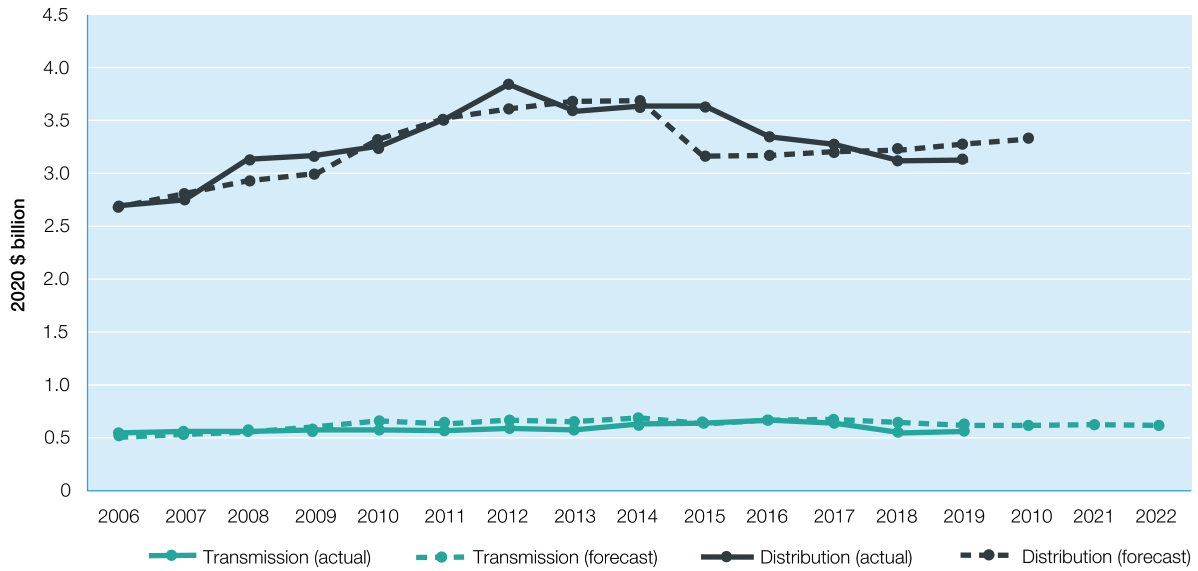
Box 3.5 Efficiency benefit sharing scheme

The AER runs an efficiency benefit sharing scheme (EBSS) that aims to share the benefits of efficiency gains in operating expenditure between network businesses and their customers. Efficiency gains occur if a network business spends less on operating and maintenance than forecast in its regulatory determination. Conversely, an efficiency loss occurs if the business spends more than forecast.

The EBSS allows a network business to keep the benefit (or incur the cost) if its actual operating expenditure is lower (higher) than forecast in each year of a regulatory period. It effectively allows a network business to retain efficiency gains (or bear the cost of efficiency losses) for the duration of the existing regulatory period, which may be up to five years. In the longer term, network businesses can retain 30 per cent of efficiency savings, but must pass on the remaining 70 per cent (as lower network charges) to customers.

The EBSS provides network businesses with the same reward for underspending (or penalty for overspending) in each year of the regulatory period. Its incentives align with those in the capital expenditure sharing scheme (box 3.4)—that is, the 30/70 split between the network business and its customers applies in both schemes. The EBSS incentives also balance against those of the service target performance incentive scheme (box 3.6), to encourage network businesses to make efficient holistic choices between capital and operating expenditure in meeting reliability and other targets.

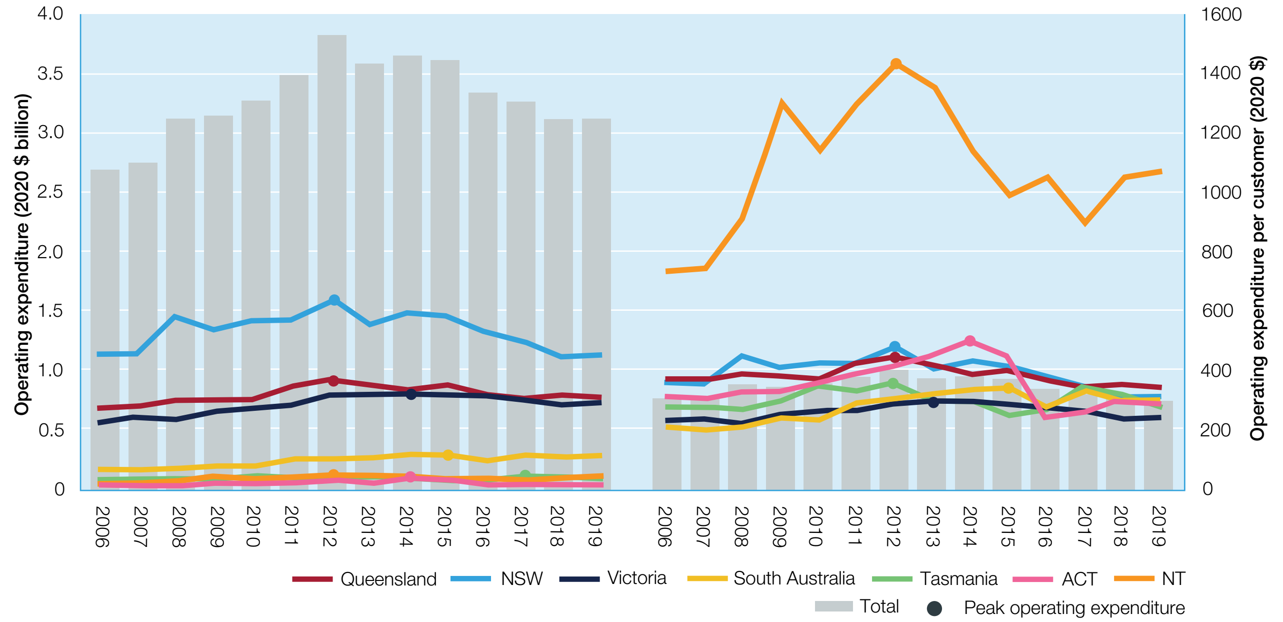
Figure 3.20
Operating and maintenance expenditure of network businesses



Note: Actual outcomes on an end-of-year basis, CPI adjusted to June 2020 dollars. Most network businesses report on a 1 July – 30 June basis. The exceptions are Victorian networks: AusNet Services (transmission) reports on a 1 April – 31 March basis, and the Victorian distribution network businesses report on a 1 January – 31 December basis. 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 modeling; AER revenue determinations; economic benchmarking regulatory information notice (RIN) responses.

Figure 3.21
Distribution network operating expenditure, by region



Note: Actual outcomes on an end-of-year basis, CPI adjusted to June 2020 dollars. Victorian network businesses report on a 1 January – 31 December basis. All other network businesses report on a 1 July – 30 June basis. 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 modeling; AER revenue determinations; economic benchmarking regulatory information notice (RIN) responses.

than it was for capital expenditure. Operating and maintenance costs are largely driven by the number of customers that the network business is supplying, and the length of line needed to service maximum demand.

3.12.2 Recent operating expenditure outcomes

Electricity networks spent $3.7 billion (or $354 per customer) on operating and maintenance in 2019—a 0.2 per cent increase on the previous year's spend. The level of operating and maintenance expenditure in 2019 was $719 million (16 per cent) lower than the $4.4 billion ($466 per customer) spent in 2012.[43]

A number of network businesses implemented efficiencies in managing their operating costs from 2015, when the AER widened its use of benchmarking to identify operating inefficiencies in some networks. The AER also introduced incentives for network businesses to spend efficiently. Not all costs are controllable by network businesses, however. Factors such as reporting obligations, changes to connections charging arrangements, and Power of Choice requirements can also impact costs.

Distribution

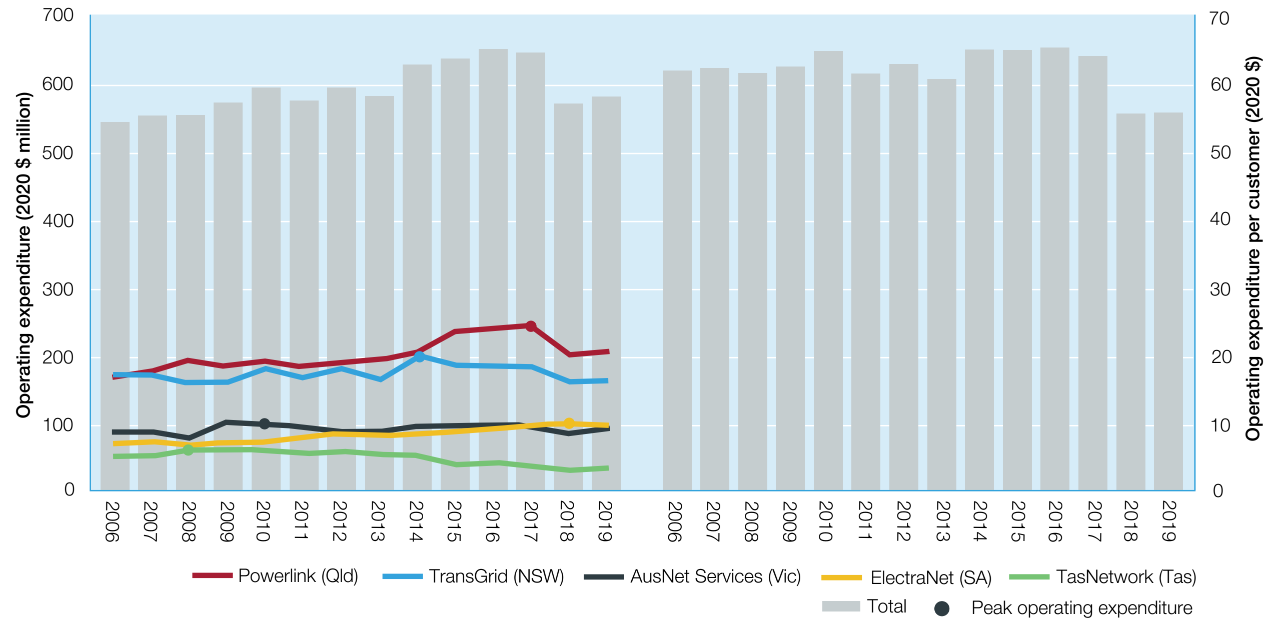
Distribution network businesses spent $3.1 billion ($298 per customer) on operating and maintenance in 2019—a 0.05 per cent decrease on the previous year's spend, and $704 million less than the peak operating and maintenance expenditure of $3.8 billion ($403 per customer) in 2012 (figure 3.21).

AER decisions in place at 1 July 2020 forecast operating expenditure to be 5 per cent lower for distribution networks than in the previous regulatory period, and 2 per cent lower for transmission. Distributors in Queensland, NSW and the Northern Territory are forecast to reduce their operating expenditure in the current regulatory period. But costs are forecast to rise in the South Australian, Tasmanian and ACT networks, and in all but one Victorian network.

Outcomes vary among jurisdictions and networks for a number of reasons. Privately owned networks in South Australia and Victoria tended to implement efficiencies

43 The assumptions underpinning data in this chapter are explained in the figure 3.7 and 3.8 notes. Unless otherwise stated, data refer to actual outcomes, CPI adjusted to 2020 dollars.

Figure 3.22
Transmission network operating expenditure



Note: Actual outcomes on an end-of-year basis, CPI adjusted to June 2020 dollars. Most transmission network businesses report on a 1 July – 30 June basis. The exception is AusNet Services (Victoria), which reports on a 1 April – 31 March basis. 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 modeling; AER revenue determinations; economic benchmarking regulatory information notice (RIN) responses.

ahead of other networks (section 3.13). In doing so, they made their levels of expenditure relatively lean, and left less scope for improvement.[44]

Because regulatory periods do not coincide across networks (figure 3.5), timing differences also play a part. Some networks—such as the distribution networks in Victoria—are operating under determinations made several years ago, while others are operating under more recent assessments.

Transmission

Transmission networks spent $581 million ($56 per customer) on operating and maintenance in 2019—a 1.8 per cent increase on the previous year's spend, and 11 per cent less than peak operating and maintenance expenditure of $649 million ($65 per customer) in 2016 (figure 3.22).

44 AER, *Annual benchmarking report, Electricity distribution network service providers*, November 2019.

Two transmission network businesses are forecast to reduce operating expenditure in the current regulatory period—TasNetworks (Tasmania) and Powerlink (Queensland)—by 12 per cent and 8 per cent respectively. ElectraNet (South Australia) and TransGrid (NSW) are forecast to increase operating expenditure in the current regulatory period by 5 per cent and 3 per cent respectively, while AusNet Services' (Victoria) operating expenditure is forecast to remain largely the same.

Latest AER decisions

In decisions on Queensland distributors for the regulatory period commencing July 2020, the AER accepted revised operating expenditure forecasts from Energex and Ergon Energy. While the AER's revealed cost and benchmarking analysis indicated Energex had been relatively inefficient in the past, it also found the network's operating efficiency improved towards the end of the period ending June 2020. The AER found Ergon Energy was historically relatively inefficient, including towards the end of the period ending June 2020. Despite this finding, it accepted Ergon's revised operating expenditure forecast, which was below the business's historical costs.

In South Australia, the AER accepted SA Power Networks' revised operating expenditure forecast for the regulatory period commencing July 2020. The revised proposal included 10 step changes from the previous period, of which the most significant (in dollar terms) was a reclassification of minor repairs from capital to operating expenditure.

A combination of AER incentives and network driven efficiencies has contributed to significant cost reductions, especially among government owned (or recently privatised) distribution network businesses in NSW, Queensland and Tasmania.[45] Those savings—from the uptake of technology solutions, and from changes to management practices, for example—are now locked in for customers.

In its decisions on NSW and ACT distributors for the regulatory period commencing July 2019, the AER accepted revised operating expenditure forecasts by Ausgrid (NSW) and Essential Energy (NSW), but adjusted those submitted by Endeavour Energy (NSW) and Evoenergy (ACT). The main adjustment was the addition of an annual 0.5 per cent productivity requirement, consistent with that applied by Ausgrid and Evoenergy in their revised forecasts.

In the Northern Territory, the AER adjusted Power and Water's forecast operating expenditure for the regulatory period commencing July 2019. Power and Water proposed lower operating expenditure than in the previous period. The AER further reduced the allowance, because it did not consider some costs incurred by Power and Water in the previous period were efficient (figure 3.23).

3.13 Electricity network productivity

The AER benchmarks the relative efficiency of electricity network businesses to enable comparisons over time. This benchmarking assesses how effectively each network uses its inputs (assets and operating expenditure) to produce outputs (such as maximum electricity demand, electricity delivered, reliability of supply, customer numbers, and circuit line length).[46] Productivity will rise if the network's outputs rise faster than the resources used to maintain, replace and augment energy networks.

45 As an example, the AER noted TasNetworks (Tasmania) appears to be responding to incentives in the regulatory framework to better manage its costs.
46 The AER applies a multilateral total factor productivity approach to benchmark network businesses.

While benchmarking provides a useful tool for comparing network performance, some productivity drivers—for example, reliability standards set by government bodies—are beyond the control of network businesses. More generally, benchmarking may not fully account for differences in operating environment, such as legislative or regulatory obligations, climate and geography.[47]

The AER, when forecasting a network's efficient operating costs, estimates the productivity improvements that an efficient network should be able to make in providing services. In March 2019 the AER published its decision to apply an annual operating expenditure productivity growth rate of 0.5 per cent when reviewing the operating expenditure forecasts of distribution network businesses. This productivity growth rate was applied to all regulatory determinations from March 2019 for electricity distribution businesses.[48]

3.13.1 Network productivity

Productivity in most NEM networks declined from 2006 to 2015, especially in the distribution sector (figure 3.24). This outcome was largely driven by:

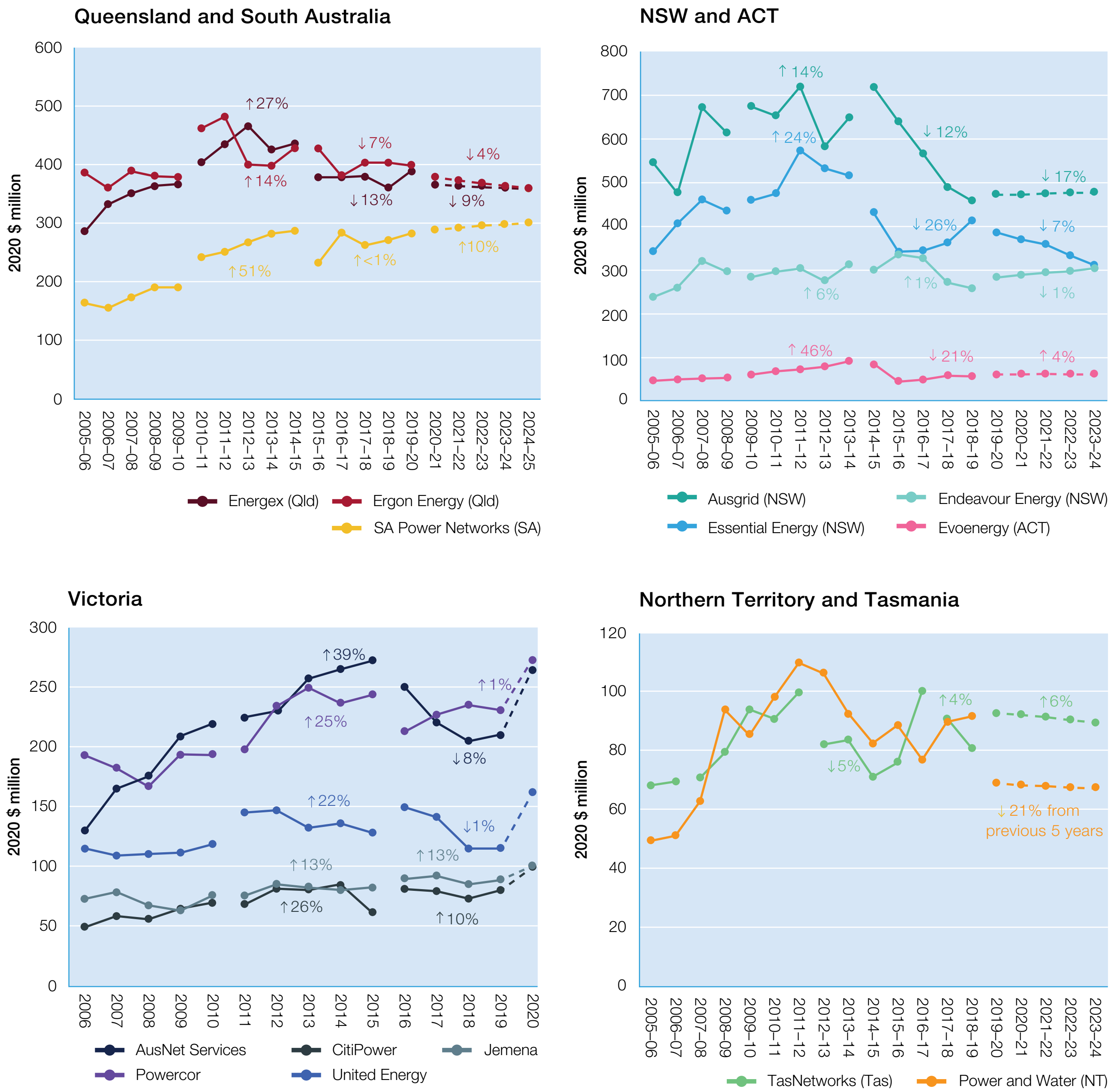
- rising capital investment (inputs) at a time when electricity demand (output) had plateaued or was declining in Australia
- for most networks, rising operating costs and declining reliability
- for distribution networks, rising expenditure to meet stricter reliability standards in Queensland and NSW, and regulatory changes following bushfires in Victoria.

The privately operated networks in South Australia and Victoria, however, consistently recorded higher productivity scores over this period than those of government owned or recently privatised networks in other regions.

The decline in productivity plateaued and then started to improve from 2012 as the NSW and Queensland governments relaxed reliability standards, network businesses implemented operating efficiency reforms and business restructuring, and new energy rules allowed the AER to scale back investment and cost proposals by some networks.

47 AER, *Annual benchmarking report, Electricity distribution network service providers*, November 2019, pp. 21–7.
48 AER, *Review of our approach to forecasting opex productivity growth for electricity distributors*, 8 March 2019.

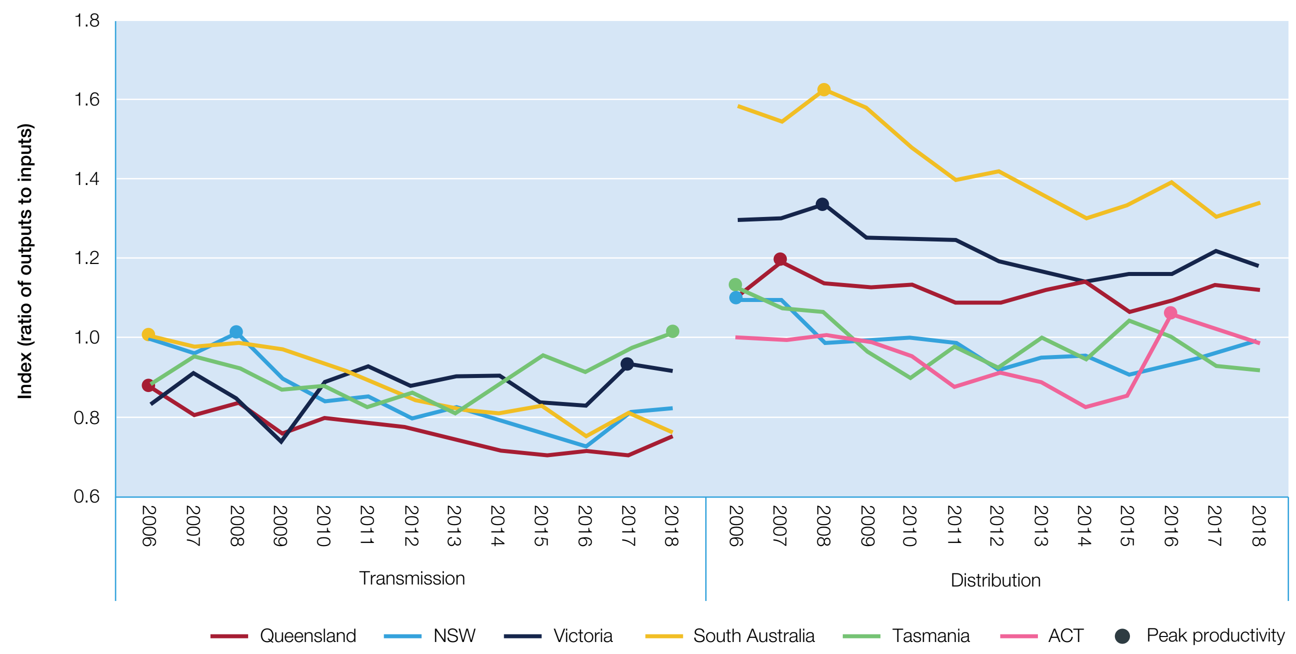
Figure 3.23
Distribution network operating expenditure, by network business



Note: Percentage values reflect growth from the previous regulatory period. Actual outcomes on an end-of-year basis, CPI adjusted to June 2020 dollars. Assumptions are set out in figure 3.8 notes.

Source: AER modeling; AER revenue determinations; economic benchmarking regulatory information notice (RIN) responses.

Figure 3.24
Electricity network productivity



Note: Index of multilateral total factor productivity relative to the 2006 performance of ElectraNet (South Australia) for transmission and Evoenergy (ACT) for distribution. The transmission and distribution indexes cannot be directly compared. Distribution outcomes are averaged for jurisdictions with multiple networks (Victoria, NSW and Queensland). The ACT does not have a transmission network.

Most network businesses report on a 1 July – 30 June basis. The exceptions are Victorian networks: AusNet Services (transmission) reports on a 1 April – 31 March basis, and the Victorian distribution network businesses report on a 1 January – 31 December basis. 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 annual benchmarking reports for electricity transmission and distribution networks.

3.13.2 Transmission network productivity

Productivity in the electricity transmission network sector grew by 2.2 per cent in 2018 over the previous year.[49] While this increase was lower than the 5.3 per cent growth achieved in 2017, it is still higher than productivity growth across the electricity, gas, water and waste services (EGWWS) sector and for the overall economy.

Across transmission network businesses in 2018:

- TasNetworks (Tasmania) and AusNet Services (Victoria) continued to be the most productive transmission networks in the NEM
- TasNetworks' productivity level set a new high among transmission businesses, bypassing TransGrid's (NSW) performance in 2008
- AusNet Services' productivity was down slightly from its peak in 2017
- TransGrid reported a significant improvement in productivity for the second consecutive year, continuing to reverse the trend of declining performance
- ElectraNet (South Australia) reported its second worst productivity outcome since 2006, and moved over that period from being one of the most productive networks to one of the least productive
- Powerlink (Queensland) continued to rank lowest on productivity levels, but significantly improved its performance.

The primary reason for productivity growth among transmission network businesses was the reduction in operating expenditure. This reduction alone was responsible for a 3.4 per cent increase in productivity. However, lower energy throughput and a greater number

49 As measured by total factor productivity.

of overhead power lines in use mitigated the net impact on productivity.[50]

3.13.3 Distribution network productivity

Productivity in the electricity distribution network sector rose by 1 per cent in 2018 over the previous year. As for transmission, this increase exceeded productivity growth for both the overall economy and the EGWWS sector.

Electricity distribution productivity has now grown for three consecutive years, mainly from networks achieving greater efficiencies in managing their operating expenditure. In 2018 distribution network productivity improved to a level that was comparable to the level in 2011, but still 8.6 per cent lower than the peak recorded in 2006.

Across distribution network businesses in 2018:

- CitiPower (Victoria) and United Energy (Victoria) further increased their productivity, with United Energy experiencing the highest improvement amongst distribution business in the NEM.
- SA Power Networks (South Australia), despite recording the largest fall in productivity of any distributor since 2006, also improved its productivity in 2018 and was the third most productive distributor in the NEM
- Powercor's (Victoria) productivity weakened in 2018, mainly as a result of a poorer reliability outcomes. Despite this fall, Powercor's productivity was still higher in 2018 than in 2015, and it remained in the top four most productive distributors.
- TasNetworks' (Tasmania) distribution productivity level was the lowest in the NEM, which partly reflected its unique network structure[51]
- Ausgrid (NSW), Endeavour Energy (NSW), and Essential Energy (NSW) improved their productivity, after historically being among the least efficient networks in the NEM.[52] The improvements were due to workforce rationalisation, the part privatisation of Ausgrid and Endeavour Energy, reforms in response to the AER's efficiency incentives, and the AER's use of economic benchmarking to set efficient operating costs. In 2018 Endeavour Energy was among the more efficient distributors in the NEM. Ausgrid, however, remained a relatively inefficient network despite significant improvement, partly because it incurred transformation costs to reduce its workforce and become more efficient.

Regulatory incentives too may be contributing to improved outcomes for both transmission and distribution network businesses. In particular, the AER allows network businesses to retain efficiency gains in operating expenditure for up to five years (box 3.5).

3.13.4 Investment disconnect

For several years from 2006, a key contributor to poor network productivity was sustained investment growth at a time when electricity demand was falling (figure 3.25). Network investment rose every year from 2006 to 2012, despite the amount of electricity delivered peaking in 2009 for transmission, and in 2010 for distribution. The earlier decline in energy delivered by transmission networks was due to the loss of some industrial loads.

Two key factors drove the mismatch between electricity use and new investment: (1) a growing divide between maximum network demand and total electricity generated, and (2) over-forecasting of maximum demand.

Changing demand patterns

The level of productivity depends on how effectively a network business uses inputs to deliver a range of outputs. Capital expenditure is largely driven by the need to meet the maximum level of demand on the network. But, since 2006, maximum demand has risen faster than average demand (figure 3.26).

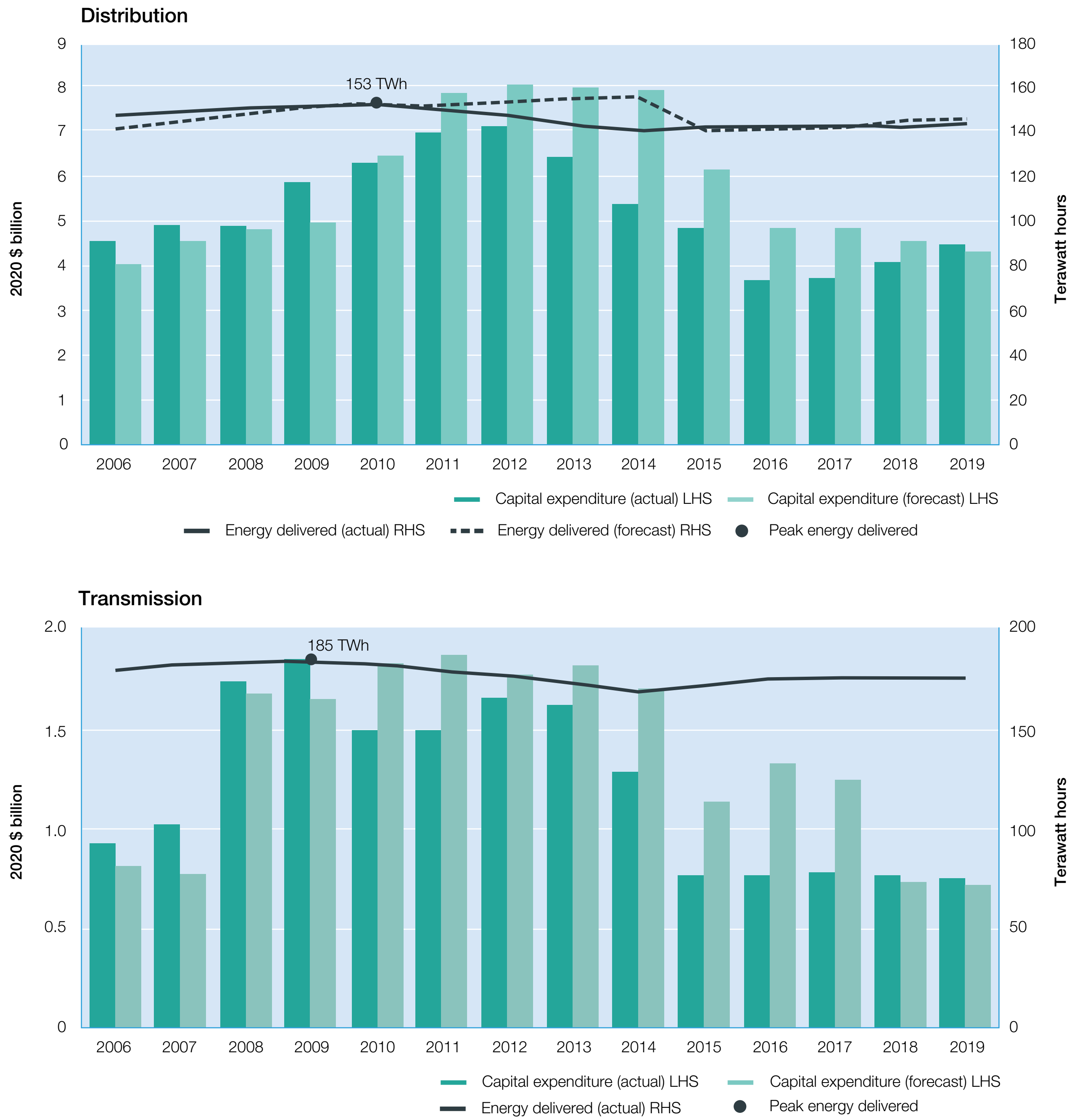
As network demand becomes 'peakier', assets installed to meet demand at peak times—which occur for approximately 0.01 per cent of the year—may sit idle (or be underused) for longer periods. This outcome is reflected in poor use rates, which weaken productivity.

The growth in customers connected to the distribution network has steadily increased by 1.5 per cent per year since 2006, and has outpaced growth in both maximum and average demand.

In 2019 the average residential customer consumed 22 per cent less energy from the distribution network than in 2006. Declining energy use is evident among all distribution networks, with 12 of the 14 distributors reporting declines of more than 15 per cent since 2006 (figure 3.27). Average consumption by business customers also fell over that period, but to a lesser extent.

50 AER, *Annual benchmarking report, Electricity distribution network service providers*, November 2019.
51 Economic Insights, *Memorandum: DNSP MTFP and opex cost function results*, November 2015, p. 4.
52 The lower historical productivity of the three network businesses was due to high operating and capital expenditure when demand for electricity was falling.

Figure 3.25
Investment and energy delivered



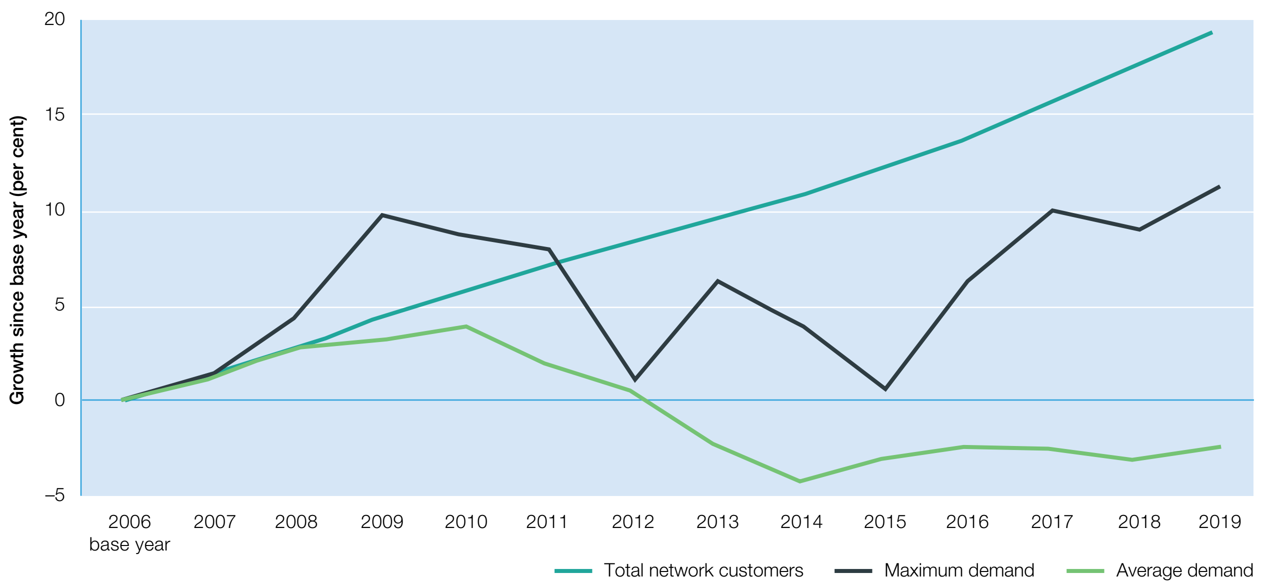
TWh, terawatt hours.

Note: Most network businesses report on a 1 July – 30 June basis. The exceptions are Victorian networks: AusNet Services (transmission) reports on a 1 April – 31 March basis, and the Victorian distribution network businesses report on a 1 January – 31 December basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Energy transported through transmission networks includes deliveries to industrial customers that take supply directly off the transmission network. Data exclude energy delivered to other transmission networks via interconnectors. Physical losses account for some differences between transmission and distribution loads.

Source: Annual benchmarking regulatory information notice (RIN) responses.

Figure 3.26
Growth in customers and demand—distribution networks



Note: Maximum demand is the network sum of non-coincident, summated raw system maximum demand (megawatts). Average demand is the total energy delivered (gigawatt hours) divided by hours in the year.
Source: Economic benchmarking regulatory information notice (RIN) responses.

Inaccurate demand forecasting

Forecasts by planning authorities and market participants consistently failed to capture a step decline in electricity use from the grid, and a flattening of maximum demand from around 2009. This decline can be attributed to multiple factors, including solar PV replacing some grid sourced electricity; housing and appliances becoming more efficient; and consumers reducing their energy use in response to higher prices. Electricity use also contracted in the manufacturing sector.[53] More recently, networks have explored demand response to meet short term peaks in demand, as an alternative to investing in long lived assets (section 3.10.7).

Inaccurate demand forecasts fuelled a wave of investment that inflated the electricity networks' RABs, which rose by 75 per cent from 2006 to 2019. This over-investment contributed to poor productivity outcomes. Capital productivity declined for all transmission networks—except AusNet Services (Victoria)—from 2006 to 2018.[54] Over-investment also drove weaker distribution network productivity, but to a lesser extent than did rising operating expenditure. As investment slowed from around 2012, productivity outcomes improved.[55]

3.13.5 Adapting to an evolving market

As the market evolves, the regulatory framework needs to encourage network businesses to make efficient choices between capital and operating expenditure solutions for network requirements. A traditional network solution to meet increasing consumer demand in an area might be to augment a zone substation, for example. But a more efficient solution might be to purchase services from a battery provider, or an aggregator of batteries, to manage peak demand.

Regulatory frameworks need to support emerging technologies and business models that have the potential to benefit consumers. Current frameworks encourage network businesses to favour (relatively expensive) long lived capital investment (which gets added to the asset base) over cheaper operating expenditure alternatives, especially if the business's regulated rate of return is higher than its actual borrowing costs.

Network businesses are also having to adapt to a new operating environment, in which distributed energy resources (DER) are changing energy flows and creating new pressure points in the system. These challenges require network businesses to develop innovative solutions to keep the network operating efficiently.

The AEMC in September 2019 recommended the introduction of a 'regulatory sandbox' toolkit to make it easier for network businesses to develop and trial innovative energy technologies and business models.[56] The toolkit allows participants to trial smaller scale innovative concepts under relaxed regulatory requirements, but within time limits and with appropriate safeguards. The proposed reforms were before the CoAG Energy Council in early 2020.

3.13.6 Network utilisation

A network's utilisation rate is a part productivity measure, indicating the extent to which a network business's assets are being used to meet maximum demand. The rate can be improved through efficiencies such as using demand response (instead of new investment in assets) to meet rising demand.

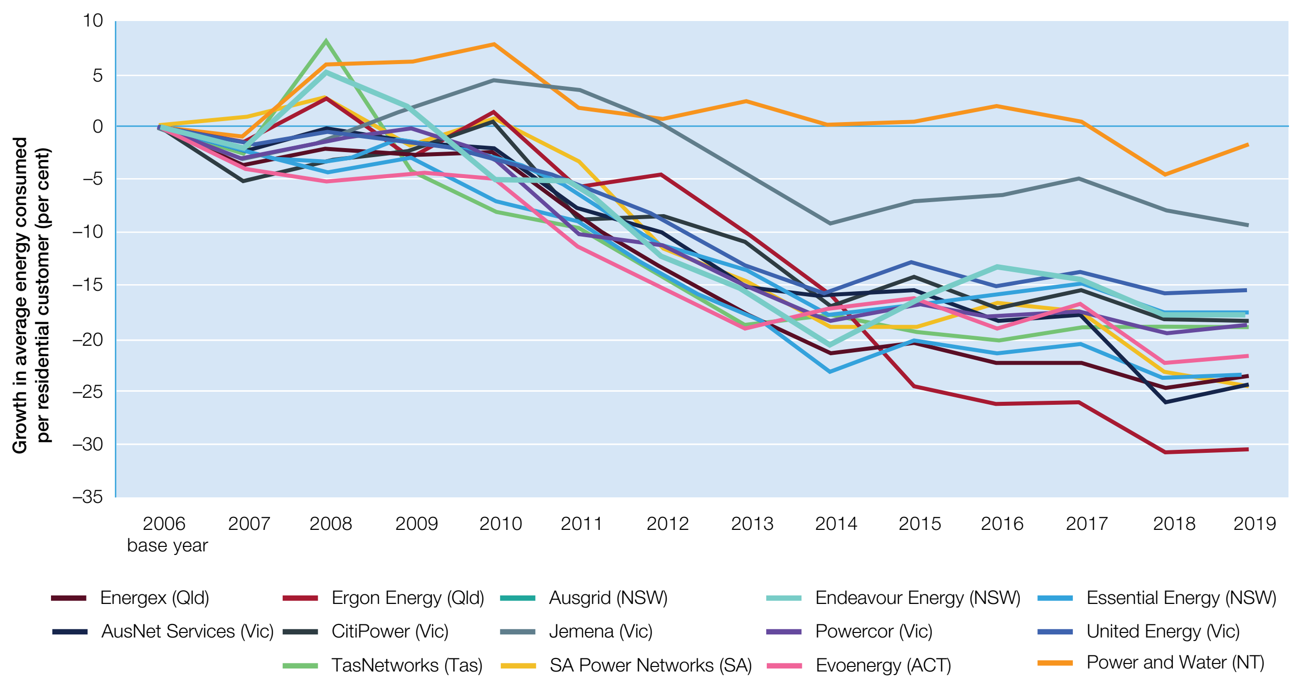
Network utilisation rates tend to be higher among privately owned distribution networks (62 per cent in 2019) than in fully or partly government owned networks (37 per cent).[57] In 2019 six of the seven most highly utilised distribution networks were privately owned, with Ergon Energy (Queensland) being the only exception (figure 3.28).

The average network utilisation amongst all distribution networks declined from 56 per cent in 2006 to a low of 39 per cent in 2015, following over-investment by many network businesses at a time of weakening electricity demand. Since 2016 maximum demand has increased by 4 per cent while network capacity has decreased by 2 per cent. In 2019 the average network utilisation among all distribution networks increased to 46 per cent, which was the highest rate since 2013.

Powercor (Victoria) has operated the most highly utilised distribution network in each year from 2006 to 2019,

53 AEMC, *Electricity network economic regulatory framework review*, 18 July 2017, pp. 37–8.
54 AER, *Annual benchmarking report, Electricity transmission network service providers*, November 2019, p. 19.
55 AER, *Annual benchmarking report, Electricity distribution network service providers*, November 2019.

Figure 3.27
Energy delivered per residential distribution customer

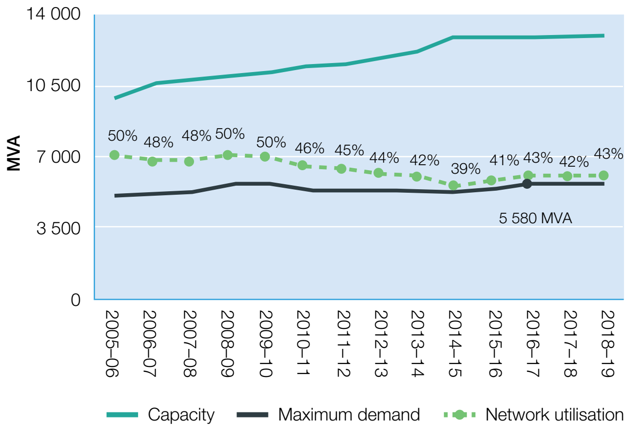


Source: Annual benchmarking regulatory information notice (RIN) responses.

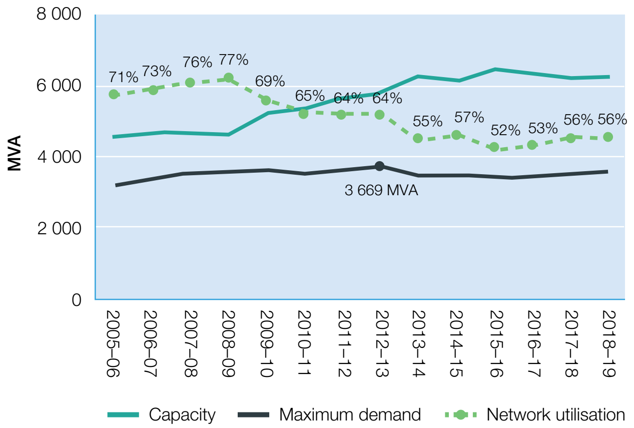
56 AEMC, *Regulatory sandbox arrangements to support proof-of-concepts trials*, 26 September 2019.
57 Section 3.3 provides a detailed assessment of network ownership.

Figure 3.28
Distribution network utilisation

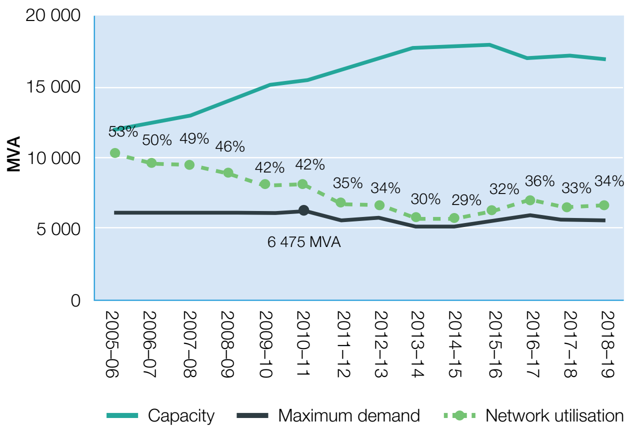
Energex (Qld)



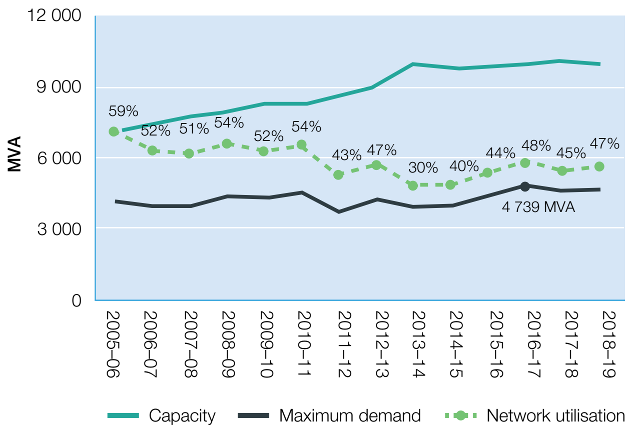
Ergon Energy (Qld)



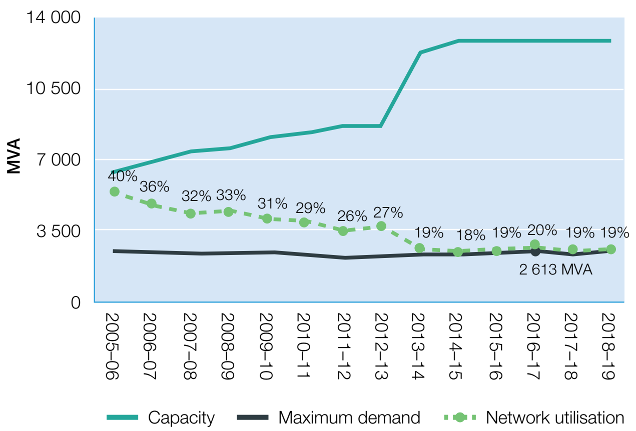
Ausgrid (NSW)



Endeavor Energy (NSW)



Essential Energy (NSW)



Evoenergy (ACT)

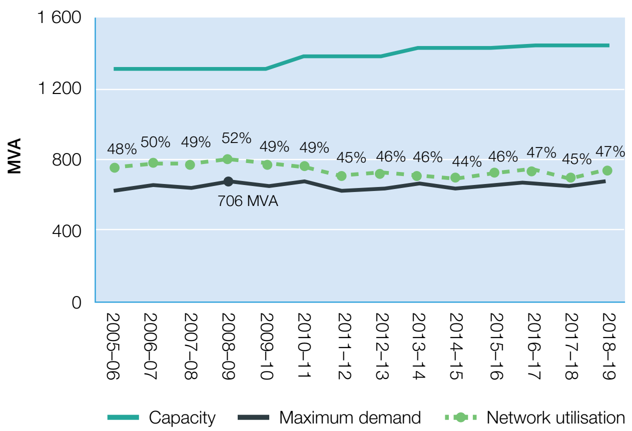
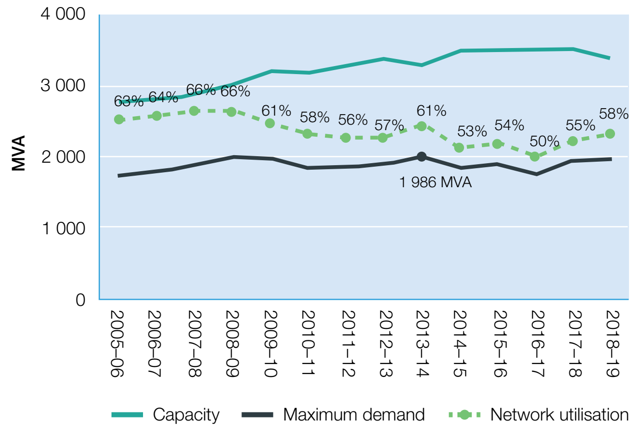
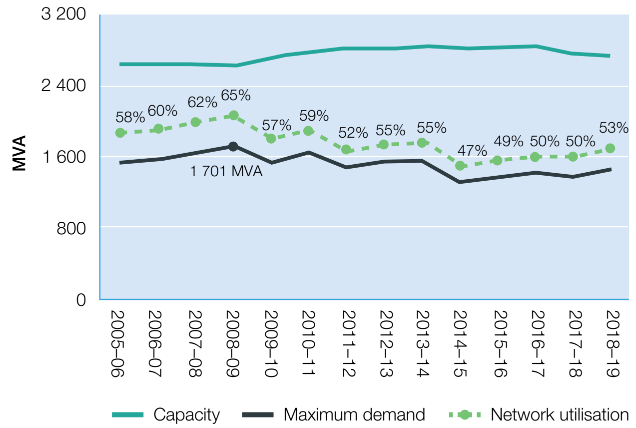


Figure 3.28
Distribution network utilisation (*cont.*)

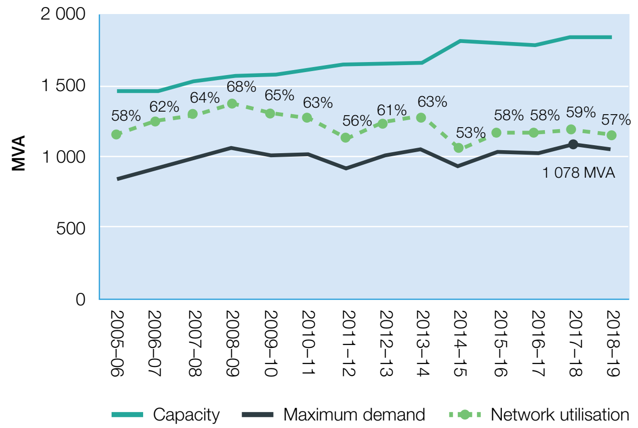
AusNet Services (Vic)



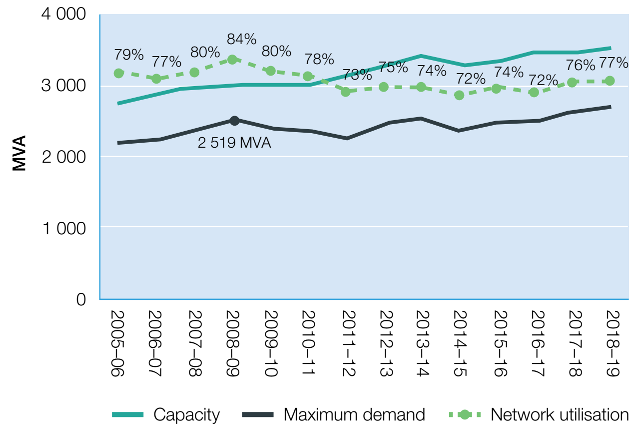
CitiPower (Vic)



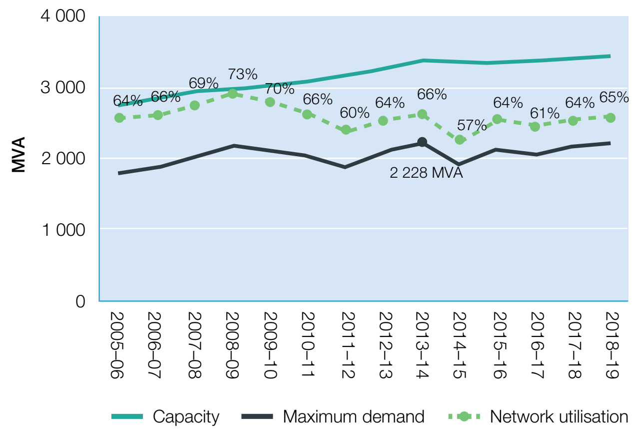
Jemena (Vic)



Powercor (Vic)



United Energy (Vic)



SA Power Networks (SA)

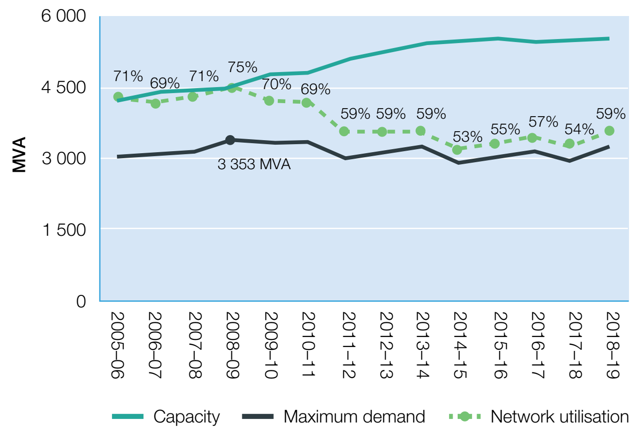
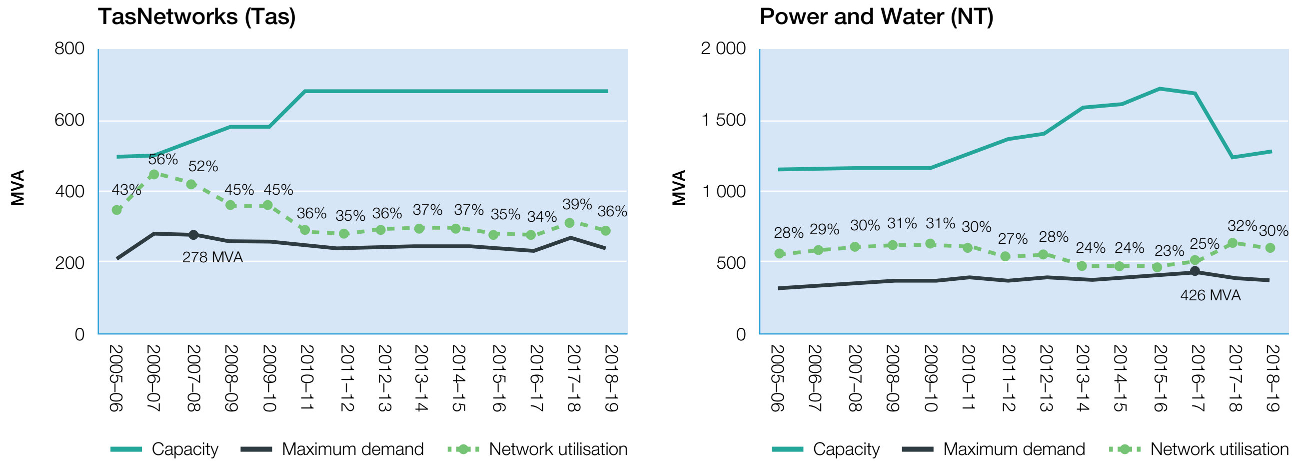


Figure 3.28
Distribution network utilisation (*cont.*)



MVA, megavolt amperes.

Note: Network utilisation is the non-coincident, summated raw system annual peak demand divided by total zone substation transformer capacity.

Source: Economic benchmarking regulatory information notice (RIN) responses.

followed by United Energy (Victoria) from 2016 to 2019. Essential Energy (NSW) has been the most underutilised distribution network in each year since 2010, followed by Power and Water (Northern Territory).

Underutilised assets raise the risk of asset stranding—whereby assets are no longer useful—unless network businesses respond to changing conditions. This risk may become more acute as the uptake of DER (such as batteries)—transforms the industry. The electricity rules do not allow for RAB adjustments to remove historical investment in stranded assets. If network charges become inflated as a result of asset stranding, then electricity consumers—who pay for those assets—may look to opportunities to bypass the grid altogether.[58]

3.14 Reliability and service performance

Reliability refers to the continuity of electricity supply to customers. Many factors can interrupt the flow of electricity on a network. Supply interruptions may be planned (for example, due to the scheduled maintenance of equipment) or unplanned (for example, due to equipment failure, bushfires, extreme weather events, or the impact of high demand stretching the network's engineering capability).

58 Grattan Institute, *Down to the wire—a sustainable electricity network for Australia*, March 2018.

A significant network failure might require the power system operator to disconnect some customers (known as load shedding).

Most supply interruptions originate in distribution networks. They typically relate to power line damage caused by lightning, car accidents, debris such as falling branches, and animals (including possums and birds). Peak demand during extreme weather can also overload parts of a distribution network. Transmission network issues rarely cause consumers to lose power, but the impact when they occur is widespread—for example, South Australia's catastrophic network failures in September 2016 caused an entire state blackout.

Electricity outages impose costs on consumers. These costs include both financial losses resulting from lost productivity and business revenues, and intangible costs such as reduced convenience, comfort, safety and amenity.

Household and business consumers desire a reliable electricity supply that minimises these costs. But maintaining or improving reliability may require expensive investment in network assets, which is a cost passed on to electricity customers. These costs form around 50 per cent of retail electricity bills. There is, therefore, a trade-off between electricity reliability and affordability. Reliability standards and incentive schemes need to strike the right balance by targeting reliability levels that customers are willing to pay for.

State and territory governments set reliability standards for electricity networks that seek to efficiently balance the costs and benefits of a reliable power supply. While approaches to setting standards have varied across jurisdictions, governments recently moved to a more consistent national approach to reliability standards. This approach factors in the value that consumers place on having a reliable power supply.

3.14.1 Valuing reliability

Understanding the value that customers place on reliability is an important consideration when setting reliability standards or network performance targets. This value tends to vary among customer types and across different parts of the network. Considerations include a customer's access to alternative energy sources, their past experience of supply interruptions, and the duration, frequency and timing of interruptions.

AEMO estimated the values that customers placed on reliability in 2014, to guide network businesses and planners on the optimal level of investment to meet customer needs.[59] These values were used to set transmission reliability standards in Victoria, South Australia and NSW. The AER also used these values as an input to its regulatory assessments for network businesses.

In July 2018 the AER became responsible for estimating how much customers are prepared to pay for reliable electricity supply. In December 2019 it published valuations for unplanned widespread outages of up to 12 hours in all jurisdictions. It drew on customer surveys and modeling to determine the values, and consulted with governments, energy regulators, industry representatives and customers.[60]

The AER's 2019 estimates were broadly similar to those estimated by AEMO in 2014, but the values varied across sectors. Both reviews found business customers tended to place a higher value on reliability than did residential customers, who were particularly concerned about long outages, and outages at peak times. Differences were also apparent across industries, but these differences changed over time: the 2019 estimates were lower than the 2014 estimates for agricultural and commercial customers, but higher for industrial customers.

The AER will develop new estimates of customers' reliability valuations every five years, and update these values

59 AEMO, *Value of customer reliability review*, September 2014.
60 AER, *Values of customer reliability, Final report on VCR values*, December 2019.

annually. The values will have wide application, including as an input for:

- cost–benefit assessments such as those applied in regulatory tests (section 3.10.5) that assess network investment proposals
- assessing bonuses and penalties in the service target incentive scheme (box 3.6)
- setting transmission and distribution reliability standards and targets
- informing market settings such as wholesale price caps.

3.14.2 Transmission reliability

Electricity transmission networks are engineered and operated to be extremely reliable, because an interruption can lead to widespread power outages. To avoid this outcome, the transmission networks are engineered with capacity to act as a buffer against credible unplanned interruptions.

Across the NEM, lost supply events due to transmission failures occurred no more than 30 times per year between 2006 and 2018 (figure 3.29). The average number of lost supply events due to transmission failures declined significantly each year from 2013, with no network business reporting more than five loss of supply events in any year between 2014 and 2018.

In 2018 the NEM experienced its fewest (seven) lost supply events due to transmission failures on record, of which ElectraNet (South Australia) experienced three. AusNet Services (Victoria) did not experience a loss of supply event between 2016 and 2018.

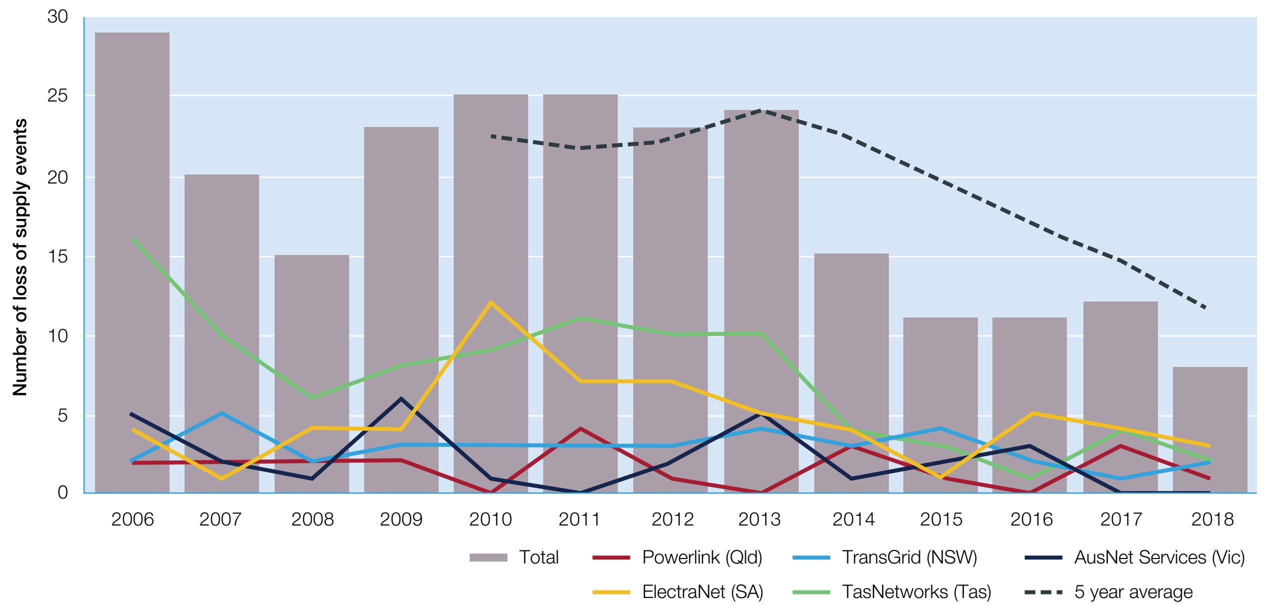
Transmission network congestion

In addition to system reliability, congestion management is another barometer of transmission network performance. All networks are constrained by capability limits, and congestion arises when electricity flows on a network threaten to overload the system. As an example, a surge in electricity demand to meet air conditioning loads on a hot day may push a network close to its secure operating limits.

Network congestion may require AEMO to change the generator dispatch order. A low cost generator may be constrained from running to avoid overloading an affected transmission line, and a higher cost generator may be dispatched instead, raising electricity prices. At times, congestion causes perverse trade flows too, such as a low priced NEM region importing electricity from a region with much higher prices.

Figure 3.29

Transmission reliability—loss of supply events



Note: Loss of supply events are the times when energy is not available to transmission network customers above a specific time period. The threshold varies across businesses, from 0.05–1.0 system minutes as published in AER decisions on the service target performance incentive scheme (STPIS). The thresholds may also vary between regulatory periods for each network.

Most transmission network businesses report on a 1 July – 30 June basis. The exception is AusNet Services (Victoria), which reports on a 1 April – 31 March basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: Economic benchmarking regulatory information notice (RIN) responses.

Transmission congestion caused significant market disruption in 2006, when rising electricity demand placed strain on the networks (figure 3.30). But network investment from 2006 to 2014—including upgrades to congested lines—eliminated much of the problem. Weakening energy demand reinforced the trend, and for several years network congestion affected less than 10 per cent of NEM spot prices. But, ultimately, consumers paid for the substantial costs of the network investment.

Congestion issues re-emerged from 2015 in Queensland (partly linked to outages associated with network upgrades) and, more recently, on cross-border interconnectors linking Victoria with South Australia and NSW. Not all congestion is inefficient, however. Reducing congestion through investment to augment transmission networks is an expensive solution. Eliminating congestion is efficient only to the extent that the market benefits outweigh the costs of new investment.

Network businesses can help minimise congestion costs by scheduling planned outages and maintenance to avoid peak periods. For this reason, the AER offers incentives for network businesses to reduce the market impact of congestion.

3.14.3 Distribution reliability

For distribution networks, the reliability of supply—that is, how effectively the network delivers power to its customers—is the focus of network performance. Around 94 per cent of supply interruptions that electricity customers experience are due to issues in their local distribution network.[61] However, the capital intensive nature of the networks makes it prohibitively expensive to invest in sufficient capacity to avoid all interruptions.

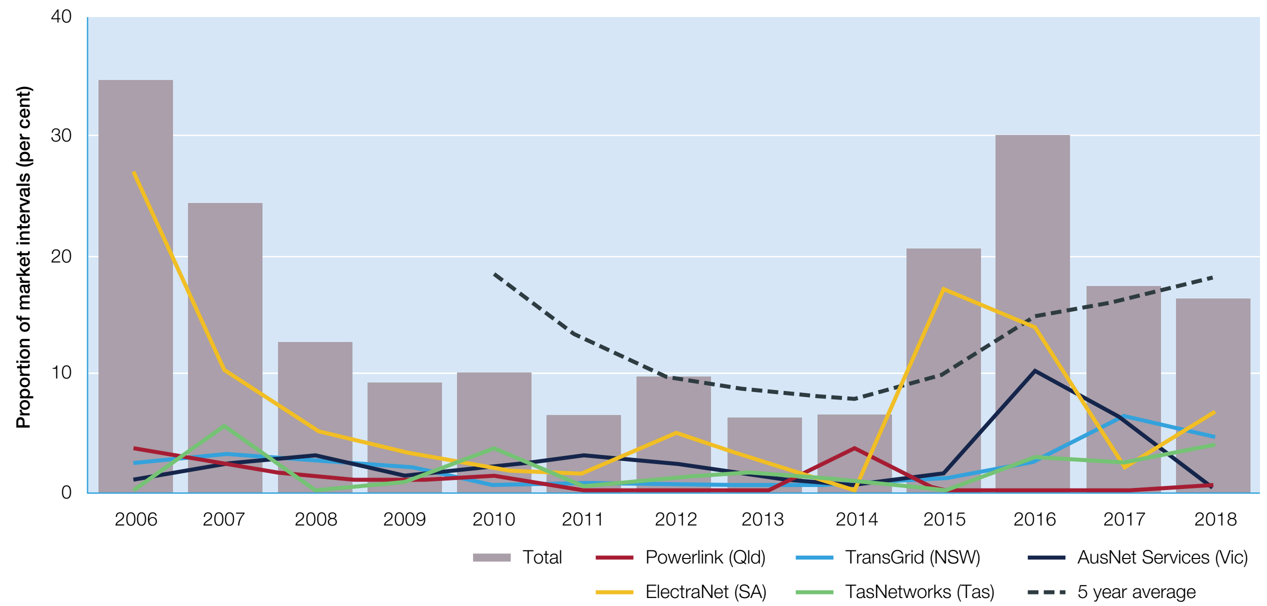
Planned interruptions—when a distribution network business needs to disconnect supply to undertake maintenance or construction works—can be scheduled for minimal impact, and the network business must provide timely notice to customers of its intention to interrupt supply. Unplanned outages—such as those resulting from asset overload or damage caused by extreme weather—provide no warning to customers so they can manage the impact of an interruption.

Jurisdictional reliability standards were historically set at high levels to protect customers from the cost and inconvenience

61 AEMC Reliability Panel, *Annual market performance review 2018*, April 2019, p. 80.

Figure 3.30

Market intervals disrupted by transmission congestion



Note: Percentage of trading intervals each year when transmission network congestion impacted the NEM spot price by more than $10 per megawatt hour. The data exclude outages caused by force majeure events and other specific exclusions.

Source: Economic benchmarking regulatory information notice (RIN) responses.

of supply interruptions. Following power outages in 2004, the Queensland and NSW Governments in 2005 strengthened reliability standards for distribution networks, requiring significant investment that drove network costs for several years. In contrast, Victoria placed more emphasis on reliability outcomes and the value that customers place on reliability. While Queensland and NSW began to relax reliability standards from 2014, the assets built to meet the high reliability standards remain, and customers continue to pay for them.[62]

Concerns that reliability driven investment was driving up power bills led to a new approach to setting distribution reliability targets.[63] The approach accounts for the likelihood of interruptions, and for the value that customers place on reliability (section 3.14.1).

Distribution reliability indicators

Two widely applied measures of distribution network reliability are the system average interruption duration index (SAIDI) and the system average interruption frequency index (SAIFI). SAIDI measures the average *duration of interruptions* experienced by the average customer each year.[64] SAIFI measures the average *number of interruptions* experienced by the average customer each year.

Comparisons across jurisdictions, and between distribution networks within jurisdictions, should be made with care. Customer density and environmental conditions differ across networks, which can impact the number of customers affected by an outage, and a network business's response time. Figure 3.31 shows the varying customer profiles of distribution networks.

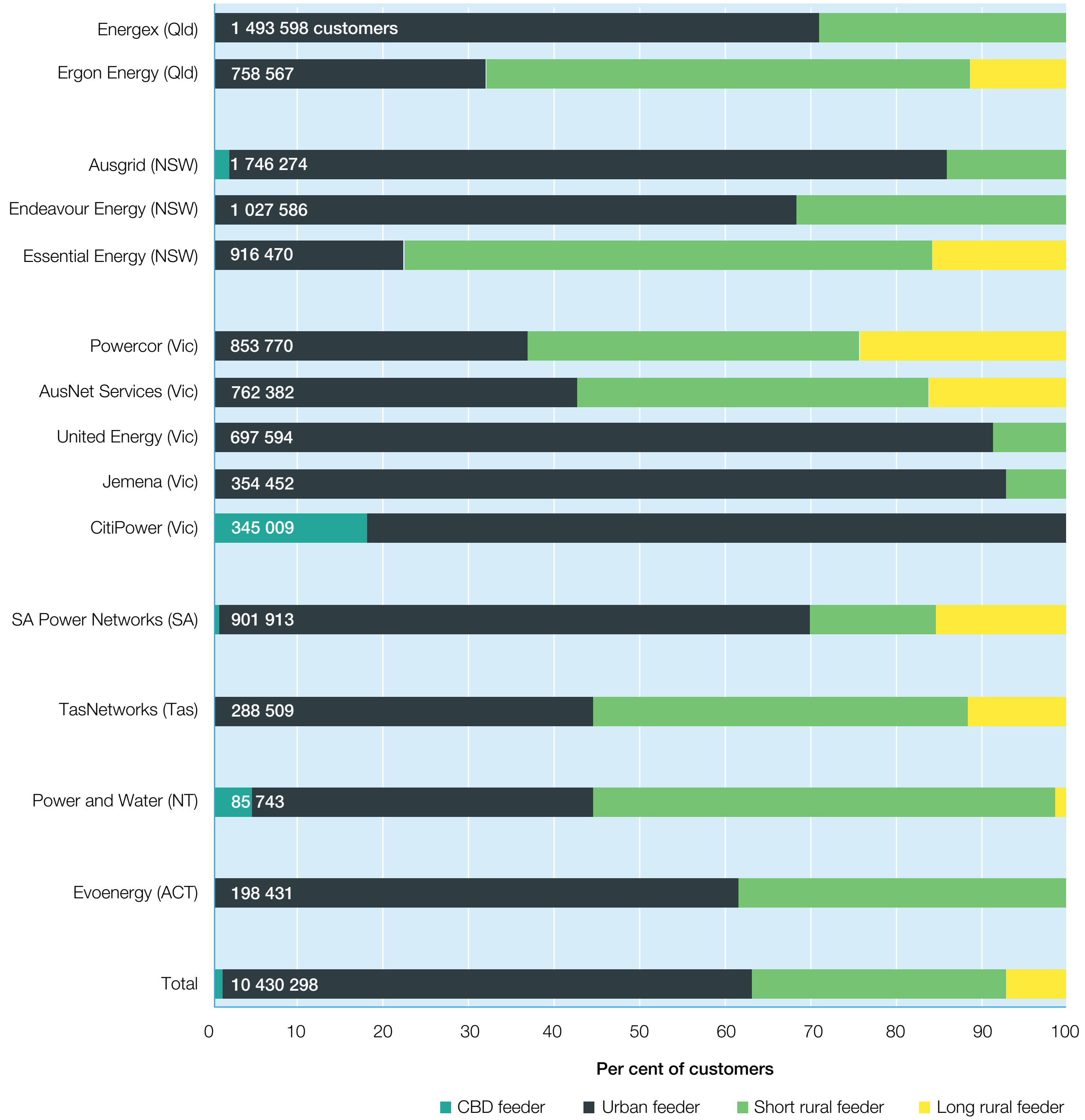
Levels of historical investment also affect reliability outcomes. As an example, underground lines protect from pollution, storms, trees, bird life, vandalism, equipment failure, and vehicle collisions with poles, but they are considerably more costly to install than overhead lines. Figure 3.32 illustrates the significant differences in line length across distribution networks, and the networks' proportions of underground and overhead lines.

62 ACCC, *Retail Electricity Pricing Inquiry, Final report*, June 2018, p. 109.

63 CoAG Energy Council, *Response to the Australian Energy Market Commission's review of the national framework for distribution reliability and review of the national framework for transmission reliability*, December 2014.

64 Unplanned SAIDI excludes momentary interruptions (3 minutes or less).

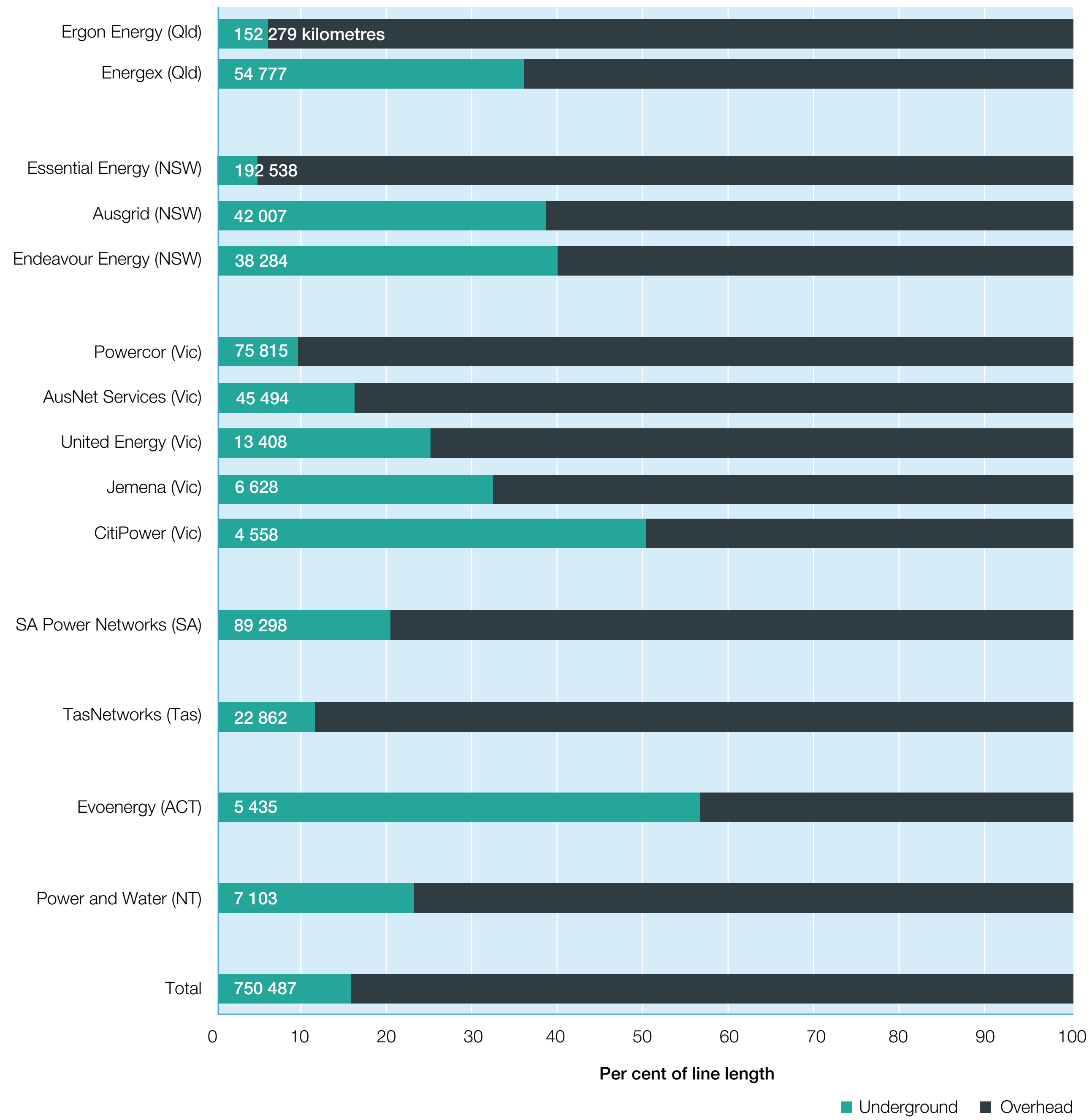
Figure 3.31
Electricity customer profile—location on network



Note: *CBD feeder* is a feeder in the CBD area of a state or territory capital supplying electricity to predominantly commercial, high rise buildings, supplied by a predominantly underground distribution network containing significant interconnection and redundancy compared with urban areas. *Urban feeder* is a feeder that is not a CBD feeder and that has a three year average maximum demand over average feeder route length greater than 0.3 megavolt ampere (MVA) per kilometre. *Short rural feeder* is a feeder that has a total feeder route length less than 200 kilometres, and that is not a CBD feeder or urban feeder. *Long rural feeder* is a feeder that is not a CBD feeder, urban feeder or short rural feeder.

Source: Economic benchmarking regulatory information notice (RIN) responses.

Figure 3.32
Circuit line length, by electricity distribution network



Source: Economic benchmarking regulatory information notice (RIN) responses.

In 2019 the average NEM customer experienced:

- 1.4 unplanned interruptions to supply
- 194 unplanned minutes off supply.

The frequency of unplanned interruptions to supply experienced by the average NEM customer was 35 per cent lower in 2019 than in 2009. The duration of interruptions experienced by the average NEM customer has been more erratic, often due to severe weather events (figure 3.33). Examples were:

- network outages associated with bushfires in Victoria in 2009
- network outages caused by strong winds and torrential rain in NSW in April 2015
- reduced reliability for Queensland customers as a result of cyclones and severe flooding in 2011, 2013, 2015 and 2017
- a power outage across almost the whole of South Australia as a result of storm damage to electricity transmission infrastructure in 2016.

Excluding the impact of events deemed beyond the network's control, an average NEM customer in 2019 experienced:

- 1.1 unplanned interruptions to supply
- 119 unplanned minutes off supply.

The AER does not determine a network's operating and capital expenditure allowances to eliminate all supply interruptions. This approach is evident in the AER's service target performance incentive scheme (STPIS) (box 3.6), in which the AER sets 'normalised' reliability targets that do not penalise a network for interruptions considered to be beyond its control.

Across the sector, 'normalised' distribution reliability levels have improved over the past decade, with lower frequency and lower duration of unplanned interruptions to supply. This improvement occurred despite distribution networks spending less than forecast on new capital projects from 2009 to 2018 (figure 3.8).

Figure 3.33 summarises the SAIDI and SAIFI outputs for each jurisdiction, as well as—where applicable—the weighted network reliability targets that the AER applies through the STPIS.

3.14.4 Incentivising good performance

Inconsistencies in the measurement of reliability across NEM jurisdictions led the AEMC to develop a more consistent approach. The AER in November 2018 adopted the AEMC's recommended definitions for distribution reliability measures, for purposes such as setting reliability targets in the STPIS.[65] More generally, the AER reviewed the STPIS to align with the AEMC's recommendations—for example, it amended the scheme to encourage distributors to reduce the impact of long outages experienced by customers at the end of rural feeders.

3.14.5 Incentives to avoid fire starts

The AER administers a Victorian Government scheme offering incentives to Victorian distributors to lower the number of fire starts originating from their network, especially in high fire danger zones and at times of heightened fire risk. Available penalties and rewards range from around $1.48 million per fire start in high risk areas on code red days, to $300 in low risk areas on a low fire danger day.

Incentive payments for 2017–18 ranged from around $5000 for the mostly urban United Energy network to almost $1 million for the predominantly rural Powercor network.[66] Victorian distributors received 77 per cent less in rewards in 2017–18 than in the previous year. Rewards were significantly lower for Powercor and AusNet Services (down 79 per cent), and United Energy (down 77 per cent) due to a higher number of fire starts in the period.

The distribution network businesses will continue to receive incentive payments only if they make sustained and continuous improvements in fire start performance. Once they make improvements, their benchmark targets are tightened in future years.

3.14.6 Customer service

While reliability is the key service consideration for most energy customers, a distribution network's service performance also relates to the business:

- providing timely notice of planned interruptions
- ensuring the quality of supply, including voltage variations
- avoiding wrongful disconnection (including for life support customers) and ensuring quick timeframes for reconnection
- being on time for appointments
- having a fast response to fault calls
- providing transparent information on network faults.

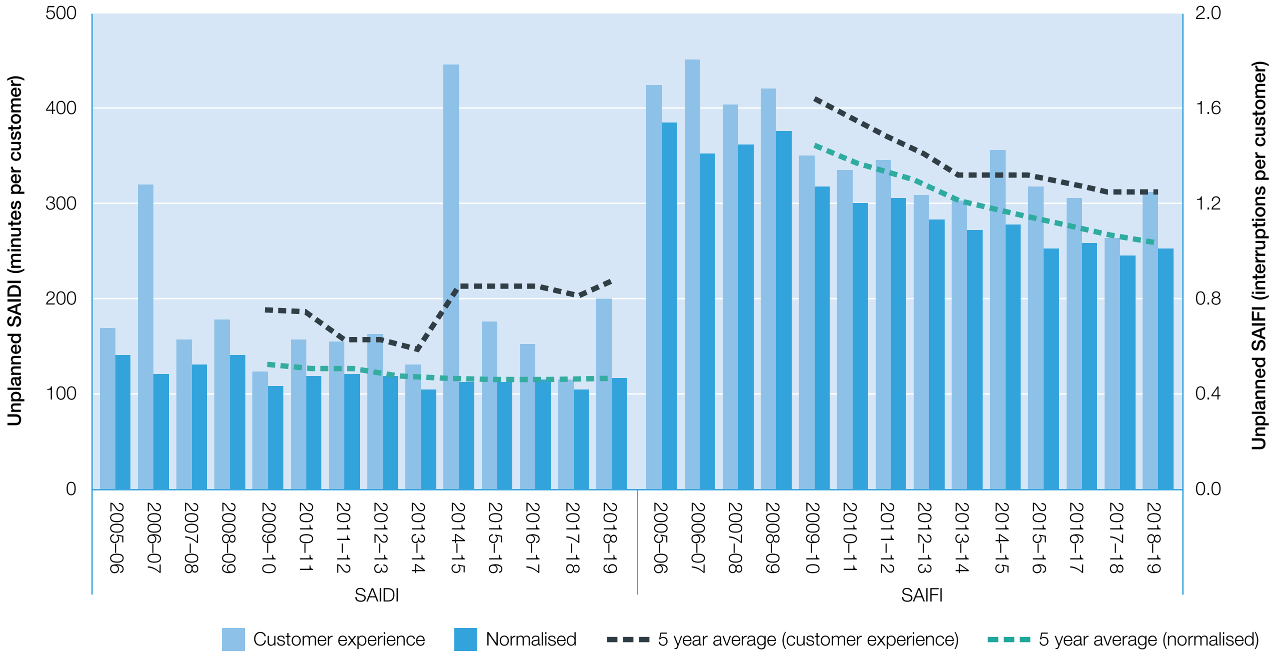
65 AER, *Amendment to the service target performance incentive scheme (STPIS) / Establishing a new Distribution Reliability Measures Guideline (DRMG)*, November 2018.

66 AER, *Victoria F-factor scheme results for the 2016–20 period*, 28 June 2019.

Figure 3.33
Distribution network reliability, by region

Figure 3.33
Distribution network reliability, by region (*cont.*)

NSW



Victoria

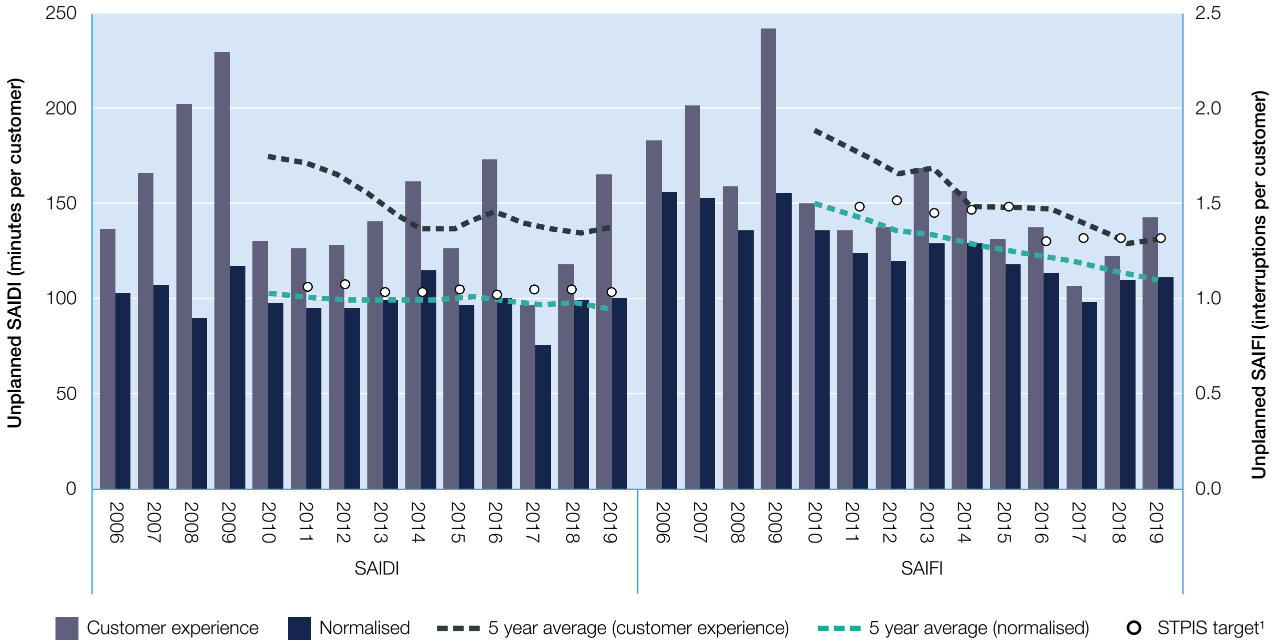
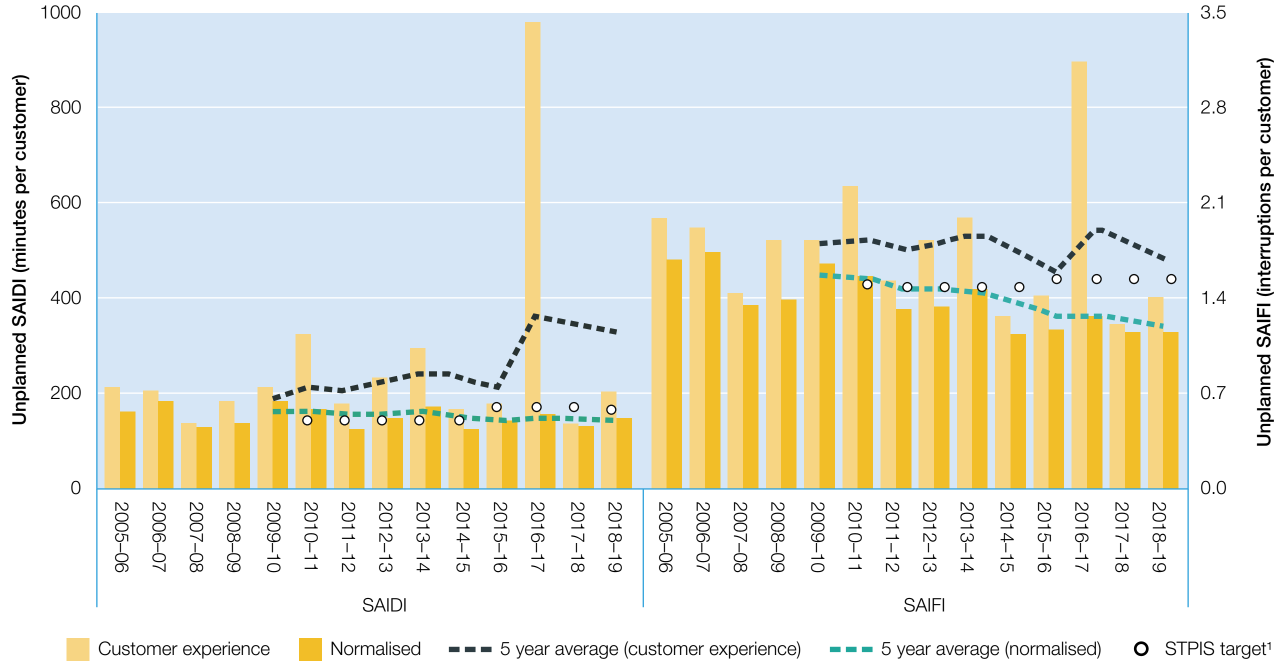


Figure 3.33
Distribution network reliability, by region (*cont.*)

South Australia



Tasmania

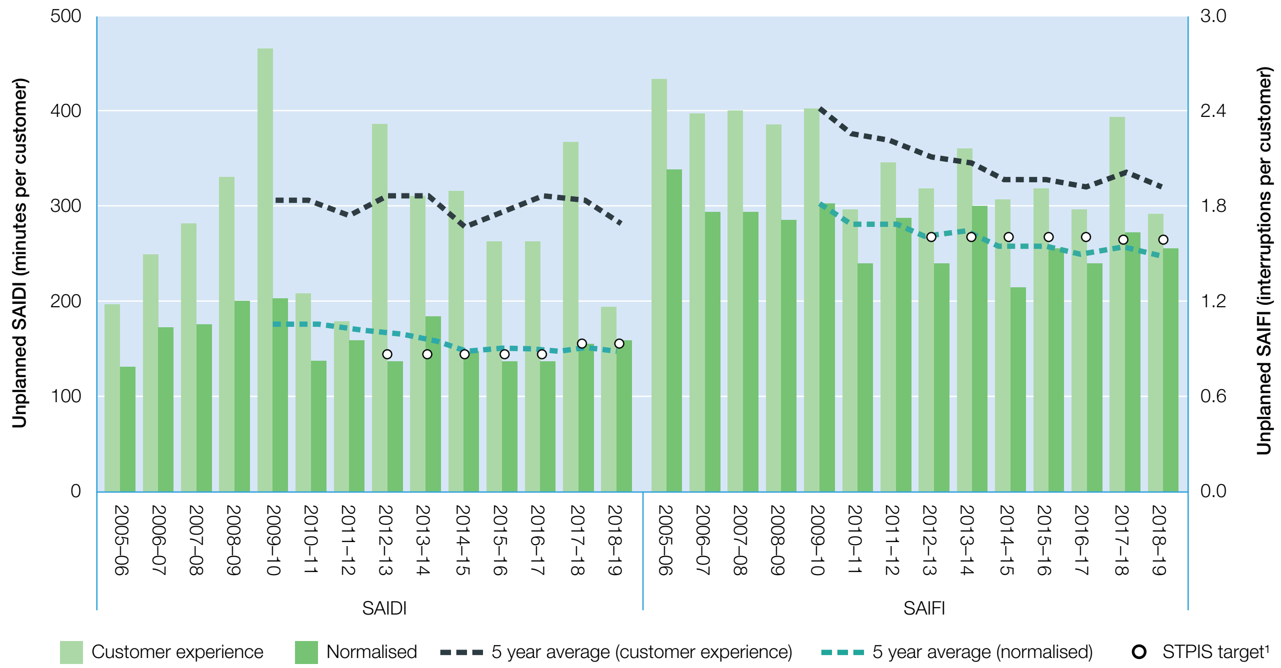
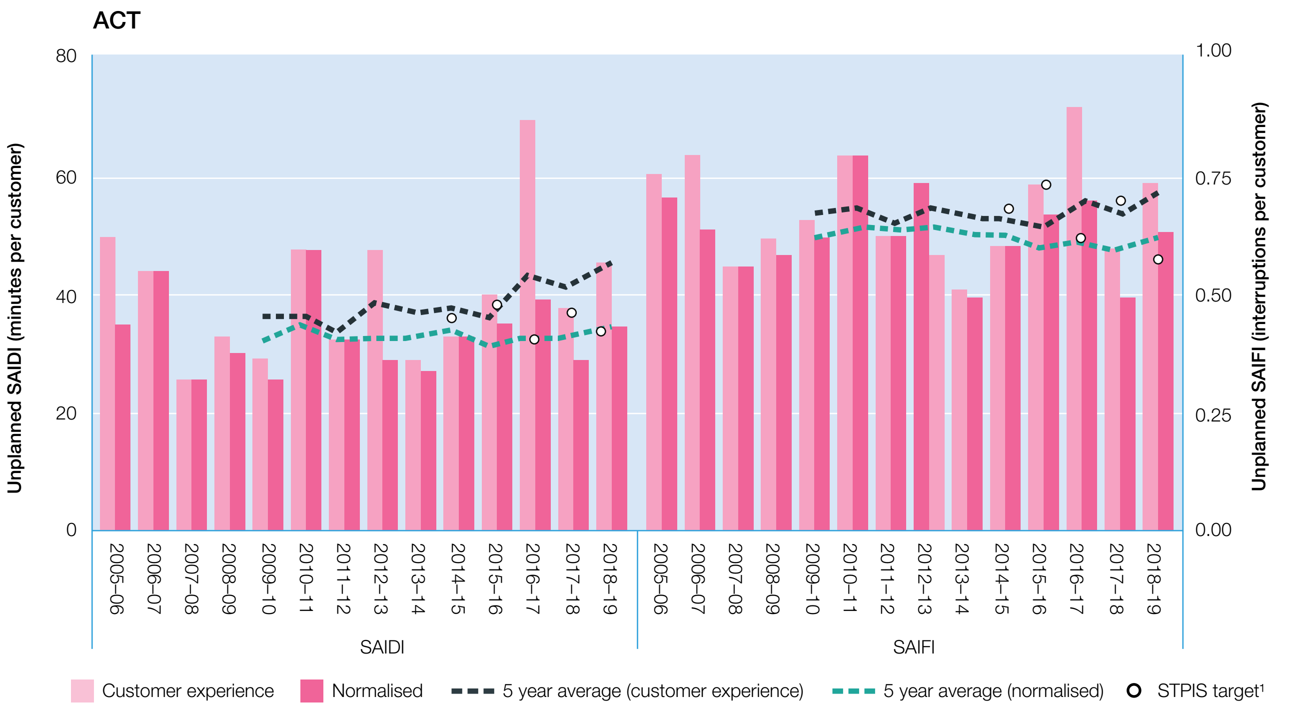


Figure 3.33

Distribution network reliability, by region (*cont.*)



SAIDI, system average interruption duration index; SAIFI, system average interruption frequency index; STPIS, service target performance incentive scheme.

1. STPIS targets are set at the feeder level. The STPIS targets shown in figure 3.33 represent weighted network level targets, calculated by multiplying the distributor's feeder level targets by the proportion of its customers on each feeder type.

Note: Victorian network businesses report on a 1 January – 31 December basis. All other network businesses report on a 1 July – 30 June basis. The NEM data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER modeling; economic benchmarking regulatory information (RIN) responses.

Individual jurisdictions set different standards for these performance indicators. Some jurisdictions apply a guaranteed service level (GSL) scheme that requires network businesses to compensate customers for inadequate performance. Because reporting criteria vary by jurisdiction, performance outcomes are not directly comparable. The AER provides an annual summary of outcomes against some of these measures for networks in NSW, Queensland, South Australia, Tasmania and the ACT.[67] Victoria reports separately on network performance in that state.[68]

The AER oversees the rules protecting energy customers who rely on life support equipment. Between December 2018 and 31 March 2020, the AER issued seven infringement notices to distribution businesses for failing to provide sufficient notice of outages to life support customers—two notices were issued to Energex (Queensland), and two notices to Evoenergy (ACT). The AER also issued three infringement notices to TasNetworks (Tasmania) for failing to provide life support customers with written notice of planned outages at least four days ahead of the outage.

67 AER, *Annual retail markets report 2018–19*, November 2019.
68 ESC, *Victorian energy market report 2018–19*, November 2019.

Box 3.6 Service target performance incentive scheme

The Australian Energy Regulator (AER) applies a service target performance incentive scheme (STPIS) to regulated network businesses. The scheme offers incentives for network businesses to improve their service performance to levels valued by customers. It provides a counterbalance to the capital expenditure sharing scheme (box 3.4) and efficiency benefit sharing scheme (box 3.5) by ensuring network businesses do not reduce expenditure at the expense of service quality. A separate STPIS applies to distribution and transmission network businesses.

Distribution

A distribution network's revenue is increased (or reduced) based on its service performance. The bonus for exceeding (or penalty for failing to meet) performance targets can range to ±5 per cent of a network's revenue.

Currently, the AER applies the distribution STPIS to two service elements:

- reliability of supply—unplanned (normalised) system average interruption duration index (SAIDI), unplanned (normalised) system average interruption frequency index (SAIFI), and momentary interruptions to supply (MAIFI)
- customer service—response times for phone calls, streetlight repair, new connections and written enquiries.

The reliability component sets targets based on a network's average performance over the previous five years. Performance is 'normalised' to remove the impact of supply interruptions beyond the network's reasonable control.

Figure 3.34 shows how distribution network businesses have performed against their reliability targets since the scheme was introduced in 2011. While the reliability performance of each network fluctuates from year to year, network businesses have generally outperformed their targets.

Figure 3.34

Distribution network performance against reliability targets

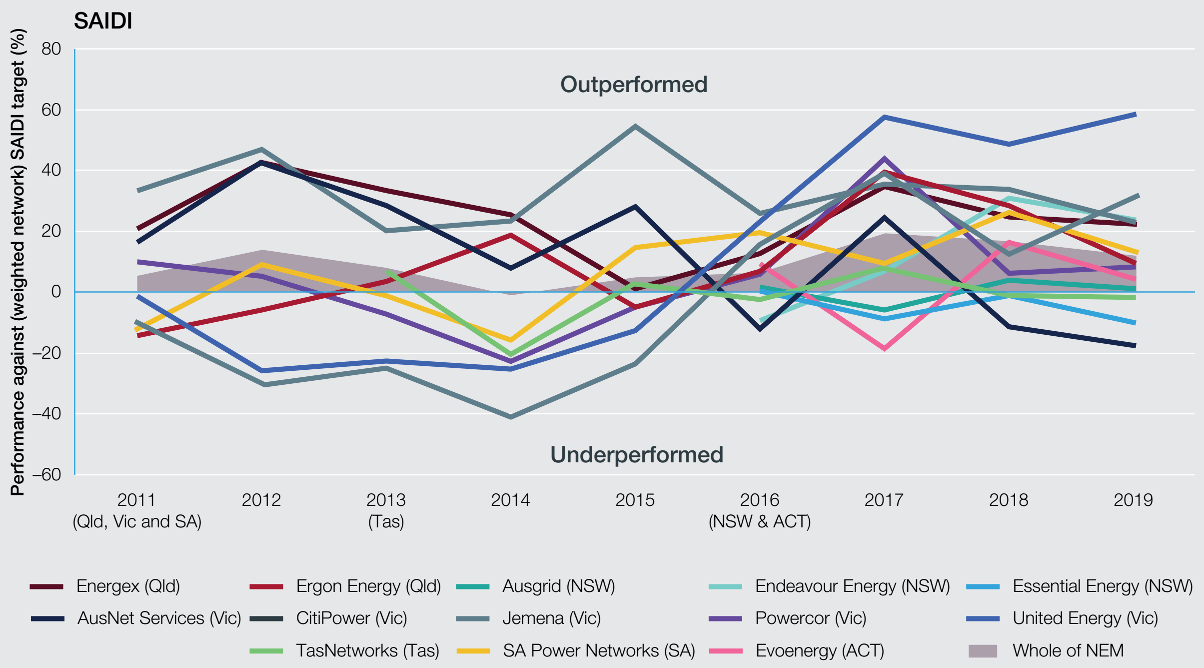
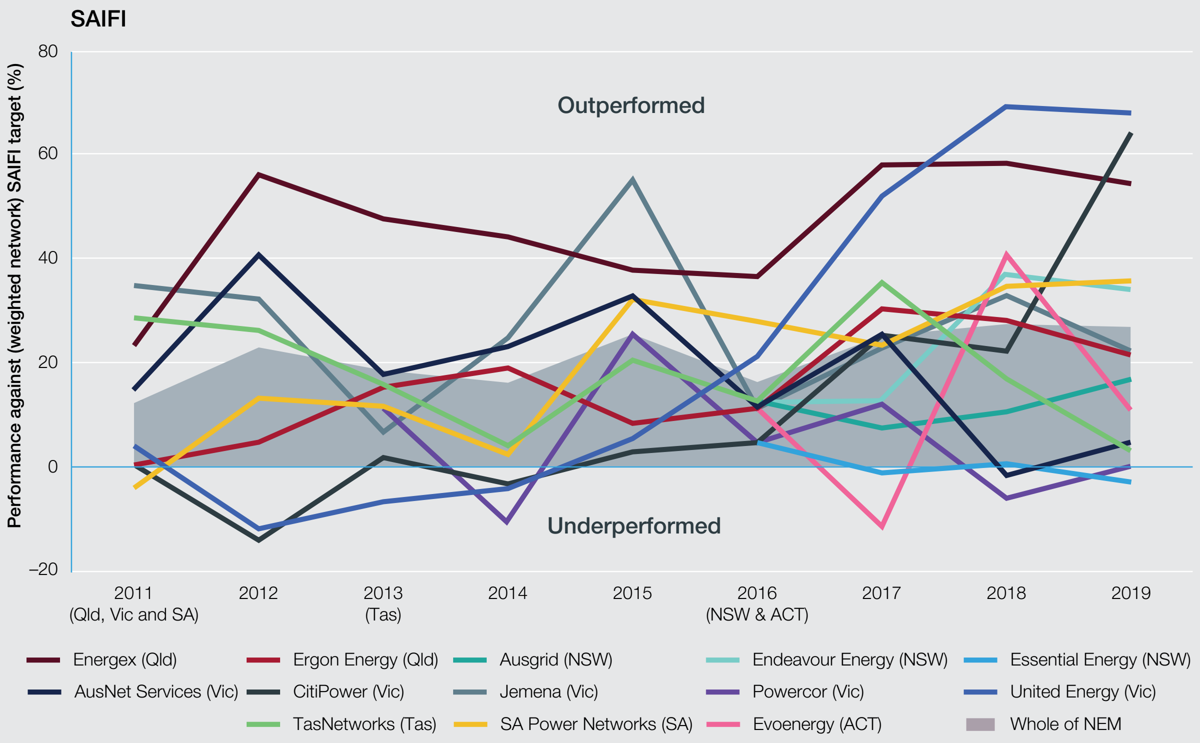


Figure 3.34
Distribution network performance against reliability targets (*cont.*)



Source: AER analysis.

Transmission

The transmission STPIS covers three service components:

- the frequency of supply interruptions, outage duration, and the number of unplanned faults on the network
- rewards for operating practices that reduce network congestion
- funds one-off projects that improve a network's capability, availability or reliability at times when users most value reliability, or when wholesale electricity prices are likely to be affected.

Financial bonuses of up to +4.5 per cent of revenue, or penalties of up to –1 per cent of revenue, are available for exceeding/failing to meet performance targets under the scheme.