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3 ELECTRICITY NETWORKS

Electricity networks transport power from electricity 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 discusses the 21 electricity networks regulated by the Australian Energy Regulator (AER), which are located in 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. The networks 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 carry electricity to residential homes and commercial premises for use by energy customers. 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 transport electricity to customers, they do not sell it. Instead, retailers purchase electricity from the wholesale market and network services from network owners, and sell them as a package to customers (chapter 1).

Electricity networks traditionally provided a one-way delivery service to customers, but their role is evolving as new technologies change how electricity is produced and used. Many small scale generators such as rooftop solar photovoltaic (PV) systems are now embedded within distribution networks, resulting in two-way power flows along the networks. Energy users with solar PV systems can now source power from the distribution network when they need it, and sell back surplus power they produce at other times. Increasingly, they can also store electricity in battery systems.

Alongside the major networks, small *embedded* distribution networks deliver power 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 21 electricity networks regulated by the AER (listed in tables 3.1 and 3.2 and mapped in figure 3.1) span 750 000 km in line length and have a combined valuation of $87 billion. They comprise seven transmission networks (valued at $19 billion) and 14 distribution networks ($68 billion).

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).

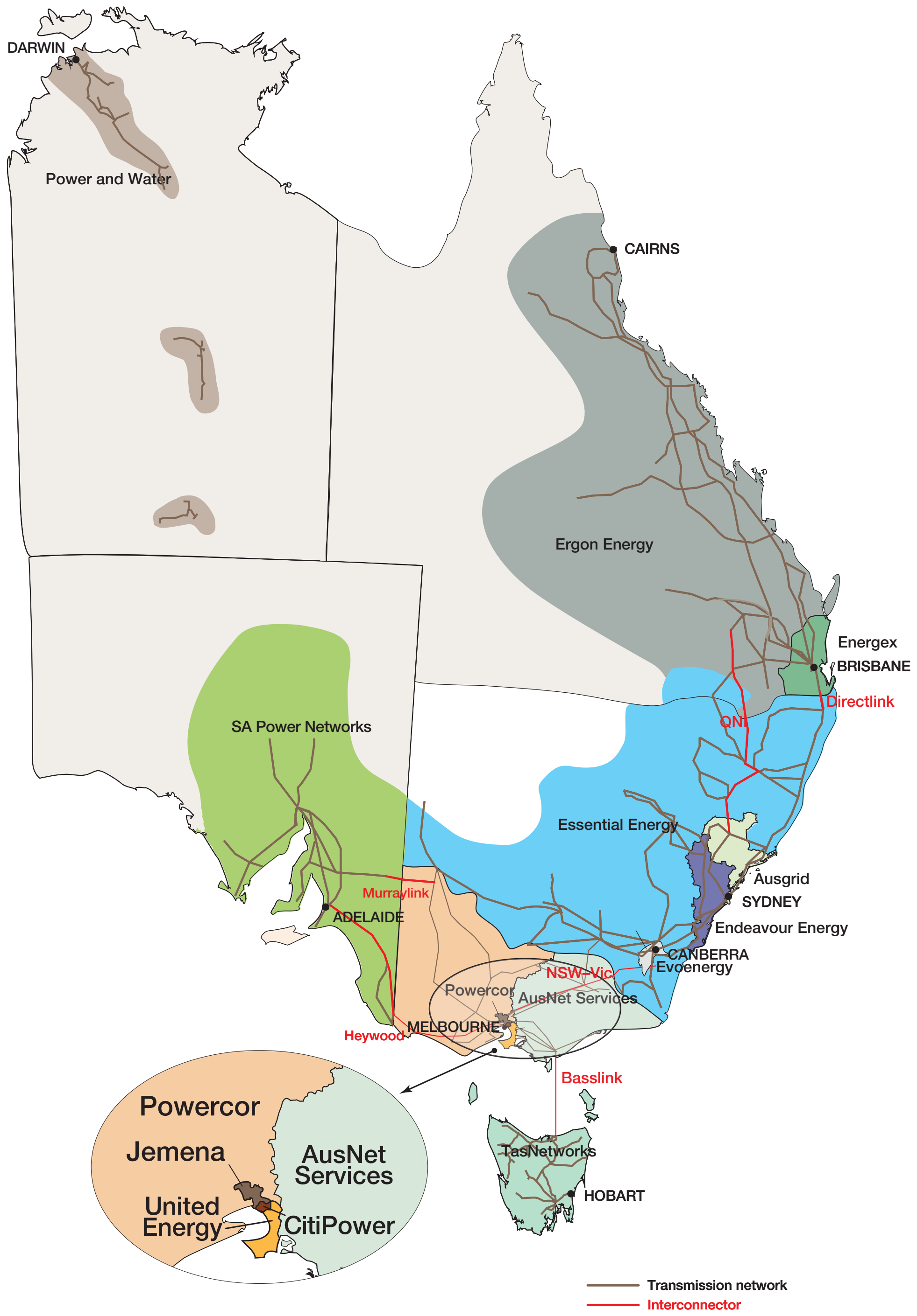
The grid delivers electricity directly to some industrial customers (such as aluminium smelters). It also connects with 13 *distribution* networks, which transport electricity to residential homes and commercial and industrial premises (table 3.2).[1] Queensland, NSW and Victoria each have multiple distribution networks serving particular areas of the state. South Australia, Tasmania and the ACT each have a single network .

Alongside its role in the NEM, in 2016 the AER became the economic regulator for electricity networks in the Northern Territory. The Territory has three separate networks—the Darwin–Katherine, Alice Springs and Tennant Creek systems—all owned by Power and Water (figure 3.1). These networks are classified as a single distribution network for regulatory purposes. The AER published its first draft revenue decision for the network in September 2018.

The AER does not regulate electricity networks in Western Australia, where the Economic Regulation Authority (ERA) administers separate arrangements. Western Power (owned by the Western Australian Government) is the state's principal network, covering the populated south west region, including Perth. Another state owned corporation—Horizon Power—services regional and remote areas.[2]

1 Some jurisdictions also have small networks serving regional areas.
2 For further information, see the Department of Treasury (www.treasury.wa.gov.au) and ERA (www.era.wa.gov.au) websites.

Figure 3.1
Electricity networks regulated by the AER



QNI, Queensland–NSW Interconnector.
Note: Basslink is not regulated by the AER.
Source: AER.

3.3 Electricity network ownership

Australia's electricity networks were originally government owned, but many jurisdictions have partly or fully privatised these assets. Privatisation began in Victoria, which sold its transmission and distribution networks to private entities in the 1990s. In 2000 South Australia privatised its transmission network and leased its distribution network. A joint venture between the ACT Government and private equity holders was established in 2000 to operate the ACT distribution network (the ACT has no transmission assets).

The NSW Government partially privatised its electricity networks through 99 year leases. It leased the 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 rural Essential Energy network remains government owned and operated.

Ownership of the privatised networks in Victoria, South Australia and NSW is concentrated among relatively few entities. These entities include Hong Kong's Cheung Kong Infrastructure (CKI) and Power Assets Holdings, Singapore Power International and State Grid Corporation of China (tables 3.1 and 3.2). Funds 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 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.

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.

3.4 How network prices are set

Electricity networks are capital intensive and their average costs decline as output rises. This 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.

But monopolies face no competitive pressure, so have opportunities and incentives to charge unfair prices. This poses serious risks to consumers, because network charges make up close to 50 per cent of a residential electricity bill.

The role of an economic regulator is to mimic the incentives network businesses 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 National Electricity Rules set the framework for regulating electricity networks, which the AER applies. The Law's regulatory objective is to promote efficient investment in, and operation and use of, electricity services for the long term interest of consumers with respect to 1) price, quality, safety and reliability and security of supply, and 2) the reliability, safety and security of the electricity system.

The AER applies this objective by seeking to ensure consumers pay no more than necessary for the safe and reliable delivery of electricity. Our regulatory toolkit to pursue this objective is wide-ranging (box 3.1), but our central role is setting the maximum amount of revenue a network business can earn from its customers for delivering electricity. We do this through a periodic *determination* or *reset* process, in which we assess how much revenue a prudent network business would need to cover its efficient costs. The network's revenues are then capped at this level for the regulatory period—typically five years. A long regulatory period helps create a stable investment environment. But it also poses challenges and risks locking in inaccurate forecasts.[3]

As part of the reset process, an electricity 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. The

3 The rules include mechanisms for dealing with uncertainties—such as cost pass-through triggers and a process for approving contingent investment projects—where costs were not clear at the time of the reset.

Table 3.1 Electricity transmission networks in the NEM

NETWORK	LOCATION	LINE LENGTH (CIRCUIT KM)[1]	ELECTRICITY TRANSMITTED (GWH)[2]	MAXIMUM DEMAND (MW)[3]	ASSET BASE ($2018 MILLION)[1]	CURRENT REGULATORY PERIOD	OWNER
STATE NETWORKS[4]							
Powerlink	Qld	14 533	54 253	11 974	7 281	1 July 2017–30 June 2022	Queensland Government
TransGrid	NSW	13 078	75 000	18 700	6 469	1 July 2018–30 June 2023	Hastings 20%; Spark Infrastructure 15%; other private equity 65%
AusNet Services / AEMO	Vic	6 560	46 829	9 347	3 148	1 April 2017–31 March 2022	Listed company (Singapore Power 31.1%; State Grid Corporation 19.9%)
ElectraNet	SA	5 520	14 525	3 355	2 523	1 July 2018–30 June 2023	State Grid Corporation 46.6%; YTL Power Investments 33.5%; Hastings Investment Management 19.9%
TasNetworks	Tas	3 564	12 427	2 456	1 448	1 July 2014–30 June 2019	Tasmanian Government
TOTALS		43 254	203 034		20 869		
STAND ALONE INTERCONNECTORS							
Directlink	Qld–NSW	63			131	1 July 2015–30 June 2020	Energy Infrastructure Investments (Marubeni Corporation 49.9%; Osaka Gas 30.2%; APA 19.9%)
Murraylink	Vic–SA	180			105	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 2017 (30 March 2017 for AusNet Services).
2. Electricity transmitted in 2016–17 (year to March 2017 for the Victorian business).
3. Non-coincident, summated maximum demand in 2016–17 (year to March 2017 for AusNet Services).
4. 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) releases; company websites; company annual reports.

Table 3.2 Electricity distribution networks regulated by the AER

NETWORK	CUSTOMER NUMBERS[1]	LINE LENGTH (CIRCUIT KM)[1]	ELECTRICITY TRANSMITTED (GWH)[2]	MAXIMUM DEMAND (MW)[3]	ASSET BASE ($2018 MILLION)[1]	CURRENT REGULATORY PERIOD	OWNER
QUEENSLAND							
Energex	1 448 247	53 757	21 355	5 464	12 181	1 July 2015–30 June 2020	Queensland Government
Ergon Energy	745 501	152 491	13 332	3 158	10 758	1 July 2015–30 June 2020	Queensland Government
NSW AND ACT							
Ausgrid	1 706 913	41 642	25 669	5 874	15 038	1 July 2014–30 June 2019	NSW Government 49.6%; IFM Investors 25.2%; AustralianSuper 25.2%
Endeavour Energy	984 230	36 993	16 716	4 635	6 133	1 July 2014–30 June 2019	Advanced Energy 50.4%; NSW Government 49.6%
Essential Energy	891 935	192 103	12 389	2 543	7 725	1 July 2014–3 0 June 2019	NSW Government
Evoenergy	191 482	5 333	2 914	683	933	1 July 2014–30 June 2019	Icon Distribution Investments 50%; Jemena (State Grid Corporation 60%; Singapore Power 40%) 50%
VICTORIA							
AusNet Services	734 644	44 907	7 673	1 715	3 843	1 January 2016–31 December 2020	Listed company (Singapore Power 31.1%; State Grid Corporation 19.9%)
CitiPower	339 400	4 550	5 917	1 399	1 853	1 January 2016–31 December 2020	Cheung Kong Infrastructure / Power Assets Holdings 51%; Spark Infrastructure 49%
Jemena	334 840	6 345	4 264	983	1 327	1 January 2016–31 December 2020	Jemena (State Grid Corporation 60%; Singapore Power 40%)
Powercor	816 349	75 121	10 720	2 450	3 701	1 January 2016–31 December 2020	Cheung Kong Infrastructure / Power Assets Holdings 51%; Spark Infrastructure 49%
United Energy	676 807	13 342	7 844	2 053	2 234	1 January 2016–31 December 2020	Cheung Kong Infrastructure 66%; Jemena (State Grid Corporation 60%; Singapore Power 40%) 34%
SOUTH AUSTRALIA							
SA Power Networks	878 300	88 971	10 215	3 011	4 013	1 July 2015–30 June 2020	Cheung Kong Infrastructure / Power Assets Holdings 51%; Spark Infrastructure 49%
TASMANIA							
TasNetworks	287 652	22 725	4 193	230	1 702	1 July 2017–30 June 2019	Tasmanian Government
NORTHERN TERRITORY							
Power and Water[4]	85 710	8 332	1 780	413	967	1 July 2014–30 June 2019	Northern Territory Government
TOTALS	10 122 009	746 612	155 518		72 407		

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

1. Customer numbers, line length and asset base at 30 June 2017, (31 December 2017 for Victorian businesses).
2. Electricity transmitted in 2016–17 (year to March 2017 for the Victorian business).
3. Non-coincident, summated, raw system maximum demand at the zone substation level in 2016–17 (2017 calendar year for Victorian businesses).
4. For regulatory purposes, Northern Territory transmission assets are treated as part of the distribution system.

Source: AER revenue decisions and economic benchmarking RINs; ASX releases; company websites; company annual reports.

AER then assesses the proposal, and if necessary amends it, to ensure revenues only recover *efficient* costs.

The AER's assessment draws on a range of inputs, including cost forecasts, benchmarking and revealed costs from past experience. The AER engages closely with stakeholders from the earliest stage of the process, including before a formal proposal is lodged. It established a *Consumer Challenge Panel* in 2013 to ensure consumer perspectives are properly voiced and considered. 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 new engagement approaches (section 3.6.2).

If the AER's assessment concludes that a business's proposals are unreasonably costly, it may ask for more detailed information or a clearer business case. If a satisfactory outcome is not reached, it may amend a network's proposal to align it with what it considers efficient.

While the AER assesses efficient operating and capital expenditure, it does not approve individual projects. Each businesses prioritises its own spending programs, although it must undertake a cost–benefit analysis for any new investment project (section 3.11).

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 so avoid or delay unnecessary investment.

Sections 3.11, 3.13 and 3.15 examine incentive schemes in more detail.

The AER publishes guidelines on its approach to assessing costs and applying incentives.

Box 3.1 The AER's role in electricity network regulation

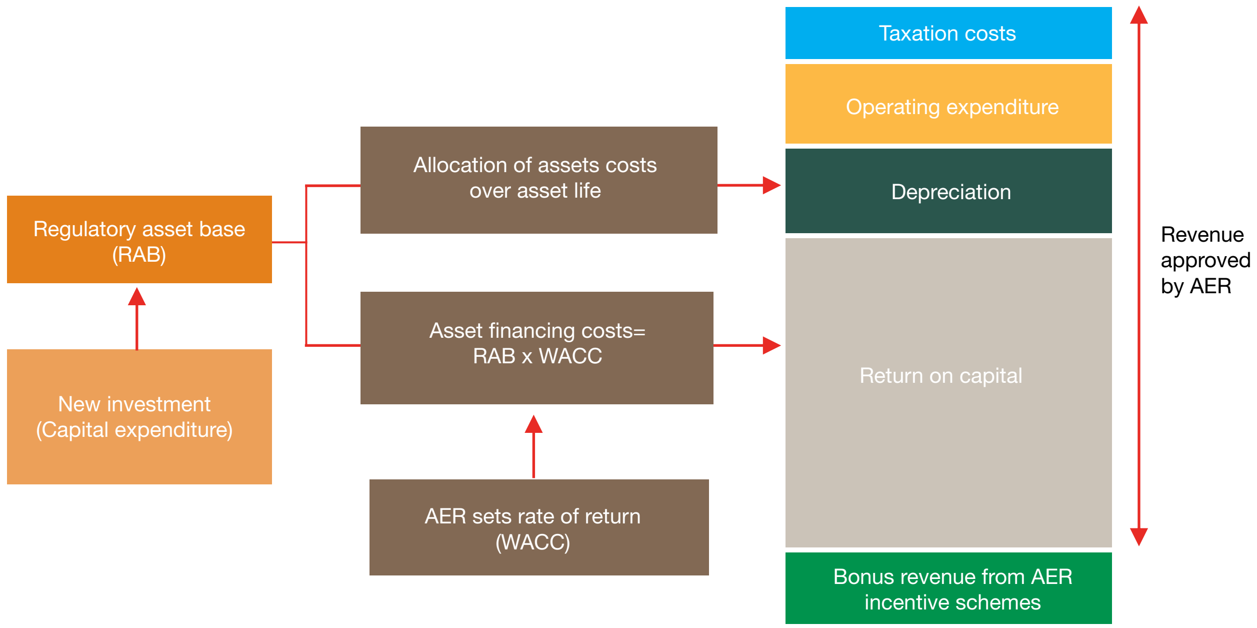
The AER sets a cap every five years on the amount of revenue a network business can earn from its customers. Alongside this central role, we undertake broader regulatory functions including:

- 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 over time 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:

- Power of Choice reforms empowering customers to make informed choices about their energy use, which ultimately help keep network costs down (sections 3.7 and 1.8)
- adopting a more consumer-centric approach to setting network revenues (section 3.6)
- publishing more information on network profitability (sections 3.12.1)
- reviewing how rates of return and taxation allowances are set for energy networks (section 3.12.2).

Figure 3.2
Forecasting network revenues



WACC, weighted average cost of capital.
Note: Bonus revenues 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.

3.4.2 The building blocks of network revenue

The AER uses a 'building block' approach to assess a network'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 who fund the network's assets and operations.

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

While network businesses are entitled to earn revenue to cover their efficient costs each year, this does *not* include the full cost of investment in new assets during the year. Network assets have a long life, so the cost of that investment is recovered over the economic life of the asset—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.

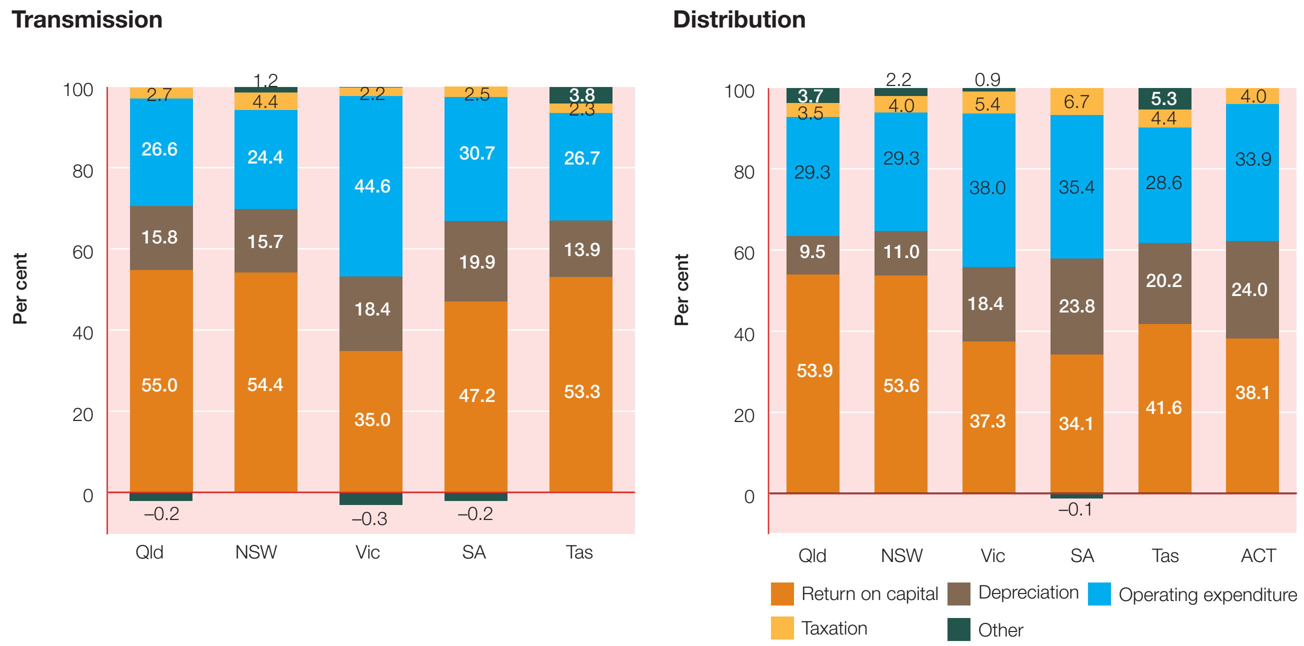
Additionally, the shareholders and lenders who fund those assets must be paid a commercial return on their investment. The AER sets the rate of return (also called the weighted average cost of capital, or WACC). The size of this return depends on:

- the value of the network's assets, measured by the regulated asset base plus forecast new capital expenditure
- the rate of return the AER allows for equity and debt used to fund those assets.

Returns to shareholders and lenders take up the largest slice of revenue for most networks, accounting for over 50 per cent of revenues for most networks in NSW, Queensland and Tasmania (figure 3.3). The rate tends to be lower in the Victorian and South Australian networks. Depreciation absorbs another 10–25 per cent of revenues.

Operating costs—such as maintenance and overheads—absorb 25–35 per cent of revenues for most networks, although the proportions tends to be higher in distribution than transmission. Taxation and other costs account

Figure 3.3
Composition of network revenues



Note: Negative values for 'other' revenues represent downward adjustments to reflect penalties for underperforming against incentive schemes, and/or reversing an earlier over-recovery of revenue.

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

for the remainder of network revenues. The AER in May 2018 launched a review into taxation costs in response to concerns about anomalies in the amount of tax paid by some network businesses relative to their forecast taxation costs (box 3.2).

Sections 3.11 to 3.13 examine major cost components in more detail.

3.4.3 Timelines and process

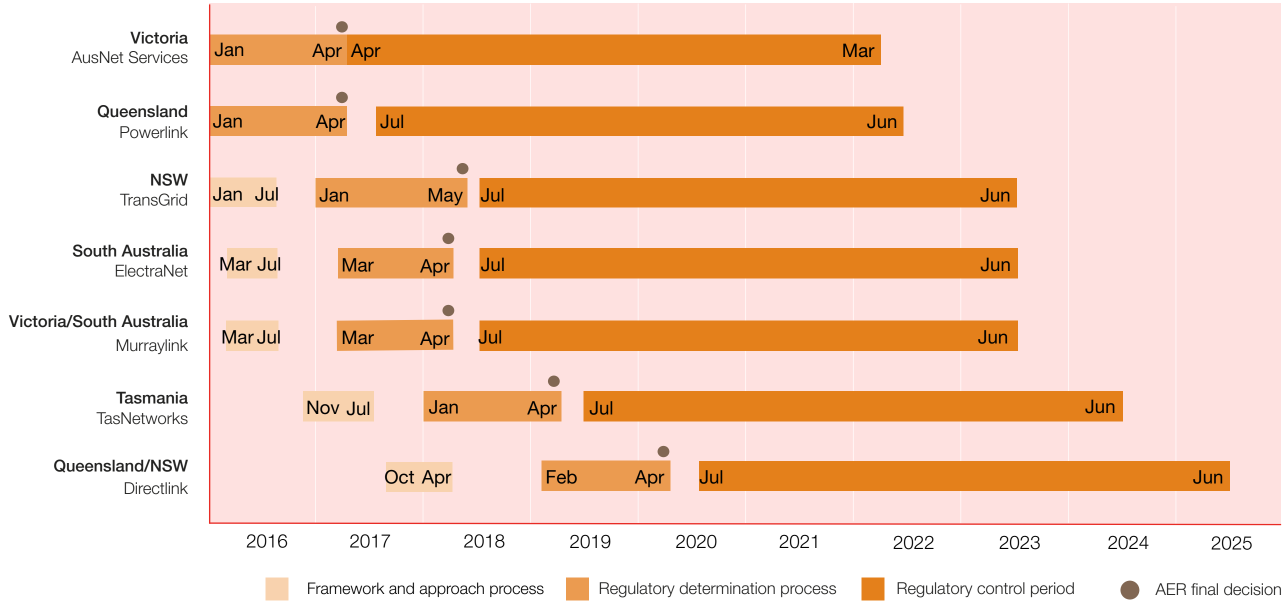
The National Electricity Law and National Electricity Rules set the regulatory framework and process, which is lengthy and highly consultative. It begins around three years before a new regulatory period, when the AER conducts early engagement with stakeholders and works with them on a framework and approach for the review. The next step is for a network business to submit a proposal setting out the revenue needed to cover its efficient costs and investment forecasts.

The AER has 15 months to formally review a revenue proposal before releasing a final decision. It consults widely with energy customers, network businesses and other stakeholders, including through issues papers and draft decisions. It conducts public forums and consult with consumer representatives, network businesses, government and investment groups. The timing of reviews is staggered to avoid bunching (figures 3.4 and 3.5).

On completing a review, the AER publishes a decision setting the maximum revenue a network can earn from its customers through network charges.[4] While the decision sets network revenues rather than prices, the two are closely related. Network businesses set their prices by allocating their allowed revenues across the customer base.[5] The AER assesses tariff structure statements on a network's pricing policies as part of the regulatory process (section 3.7.1), and conducts annual reviews to ensure

4 In transmission, the AER determines a cap on the maximum revenue a network can earn during a regulatory period. In distribution, revenue caps apply in all states except the ACT, where an average revenue cap links revenue to volumes of electricity sold.
5 Traditionally, each customer paid a fixed charge per day plus a use charge based on actual energy use. These arrangements are evolving under new pricing structures encouraging customers to factor in how their energy use impacts network costs. Energy demand at peak times (such as to run an airconditioner on a hot day), for example, puts more strain on a network than off-peak demand. Pricing reforms to address this issue form part of the Power of Choice program (section 3.7.1).

Figure 3.4
AER decision timelines—electricity transmission networks



Note: Timelines for AER decisions effective from 2017 or later. The latest information is available at www.aer.gov.au/networks-pipelines/determinations-access-arrangements.
Source: AER.

prices are consistent with the revenue decision and reflect efficient costs.

3.5 Recent AER revenue decisions

The AER in 2018 made final revenue decisions for electricity transmission networks in South Australia (ElectraNet) and NSW networks (TransGrid), and the Murraylink interconnector between Victoria and South Australia. The decisions cover the five year regulatory period 1 July 2018 to 30 June 2023 (table 3.3).

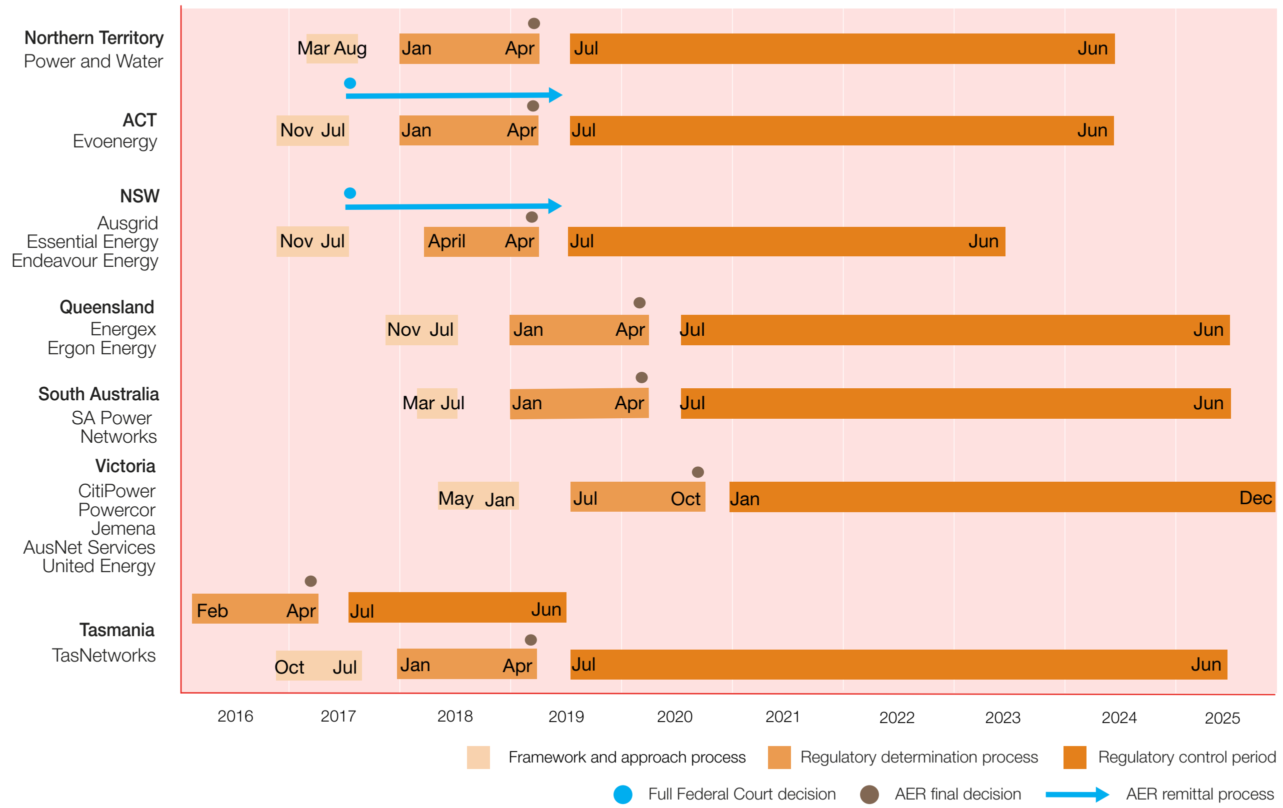
In 2018 the AER also remade revenue decisions for NSW and ACT electricity distribution networks for the regulatory period 2014–19, following orders from the Full Federal Court (section 3.5.2). And it released draft decisions on new revenue proposals for electricity networks in Tasmania, NSW and the ACT, and its first draft assessment for the Northern Territory.

The AER's transmission decisions reduced revenues for ElectraNet by 8.4 per cent and TransGrid by 6.3 per cent (in real terms), compared with revenues in the previous regulatory period. The reductions reflect the network's lower financing costs and less need for new investment due to subdued electricity demand. But the AER's Murraylink decision allowed a revenue increase of 9.4 per cent because higher returns to investors were required to fund major capital investments.

The AER accepted much of ElectraNet's proposal as reasonable, including its operating and capital expenditure forecasts. It also found ElectraNet had engaged constructively with its customers during the review process. Overall, the decision will marginally reduce average transmission charges in South Australia, although the impact on retail customer bills is negligible (partly because transmission charges only comprise 7 per cent of a typical customer bill).

The AER scaled back TransGrid's revised revenue proposal by 1.5 per cent and its capital expenditure forecast by around 20 per cent (though capital expenditure is still likely to be higher than in the previous regulatory period). Despite this, transmission charges in NSW and the ACT will rise because a phased refund to consumers of previously over-recovered revenues will end in 2018. The AER estimated a typical residential electricity bill will be around 0.5 per cent

Figure 3.5
AER decision timelines—electricity distribution networks



Note: Timelines for AER decisions effective from 2017 or later. The latest information is available at www.aer.gov.au/networks-pipelines/determinations-access-arrangements.
Source: AER.

higher in NSW in the new regulatory period than in 2017–18 (in nominal terms).

All three networks forecast the need for major new investment projects in the upcoming period (section 3.11.1). The AER approved some projects outright, but others only on a contingent basis.

3.5.1 Legal reviews of AER decisions

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

From 2008–16 network businesses and other parties applied for limited merits review of 22 of the AER's 35 electricity decisions. Consumers and governments were invariably unsuccessful in arguing that network revenues should be decreased.[6] But network businesses often succeeded in having their rates of return and revenues increased.

From 2008–14, Tribunal decisions added $3.2 billion to network revenues. In later decisions, network businesses sought another $6 billion in revenues above what the AER had determined.[7]

Concerned by the impacts of these appeals on energy customers, the Australian Government in October 2017 abolished limited merits review of AER revenue decisions. Network businesses can no longer dispute discrete elements of an AER decision before the Tribunal. Following the abolition, the AER noted its commitment to a more

6 AER, *Review of the limited merits review framework*, AER submission to COAG Energy Council, October 2016.
7 ACCC, *Retail Electricity Pricing Inquiry—Final Report*, June 2018, p. 114.

Table 3.3 **Recent AER revenue decisions—key outcomes**

REGION		DECISION DATE	% CHANGE FROM PREVIOUS PERIOD REVENUE	OPERATING EXPENDITURE	CAPITAL EXPENDITURE	RATE OF RETURN (%)[1]	RETAIL BILL IMPACT (%)[2]
TRANSMISSION NETWORKS							
NSW	TransGrid	18 May 2018	-6.3	4.6	8.5	6.5	0.5
South Australia	ElectraNet	30 April 2018	-8.4	4.4	-38.3	5.7	<0.1
Vic–SA interconnector	Murraylink[3]	30 April 2018	9.4	0.2	0.8	5.7	<0.1

1 Rates of return is 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 change in average annual customer bill compared with customer bill in final year of previous period, adjusted for inflation, assuming retailers pass through outcomes of the decision.

3 Murraylink revenue is collected from customers in South Australia and Victoria, and is a small part of the overall transmission charges in those states.

Source: AER estimates.

collaborative approach to network regulation, driven by customers' best interests (section 3.6.2).

While limited merits review is no longer available, various legal proceedings initiated under the regime continued during 2017 and into 2018:

- In May 2017 the Full Federal Court dismissed elements of an appeal by the AER against an earlier ruling by the Tribunal. The Tribunal had found the AER made errors relating to operating expenditure and return on debt in its revenue decisions for five energy networks in NSW and the ACT. The AER's work to remake those decisions continued throughout 2018 (section 3.5.2).
- In October 2017 the Tribunal affirmed the AER's revenue decisions for five Victorian electricity distribution networks and ACT gas distribution pipelines. The Tribunal rejected all grounds of review sought by the businesses to recover an additional $197 million revenue from customers. The AER's original decisions to reduce the revenue the six businesses can recover from consumers therefore stands.
- In January 2018 the Full Federal Court dismissed an appeal by SA Power Networks against an earlier ruling by the Tribunal to affirm the AER's revenue decision for the network. The AER found the network required $3.8 billion to deliver safe, secure and reliable power to South Australian households and businesses. The business sought $4.5 billion.

  Areas of disagreement between the regulator and the network included the rate of return, tax issues and labour cost forecasts. The ruling meant South Australian consumers received the full savings from the AER's 2015 decision, which reduced the network component of consumer bills by around 10 per cent.

The Full Federal Court's ruling on SA Power Networks was the final matter settled under the limited merits review regime.[8]

Many applicants for limited merits review also filed applications with the Federal Court for judicial review of the same AER decisions. Network businesses withdrew all applications following the abolition of limited merits review in October 2017.

3.5.2 Remaking the NSW and ACT revenue decisions

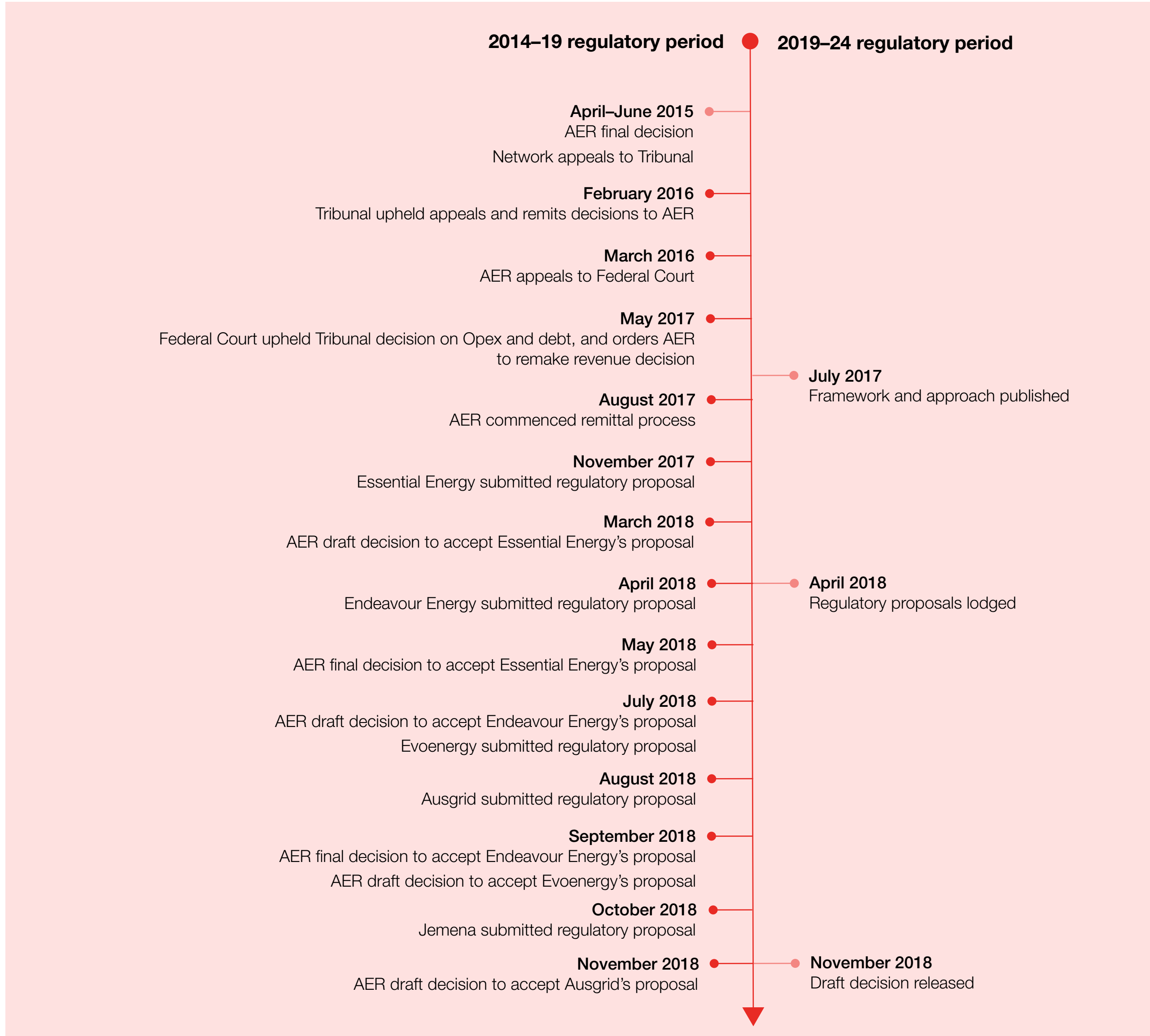
One of the longest running appeal processes (with ongoing ramifications in 2018) related to AER's 2015 revenue decisions for five NSW and ACT energy networks (figure 3.6). The decisions covered three NSW electricity distributors (Essential Energy, Endeavour Energy and Ausgrid), the ACT electricity distributor (Evoenergy, formerly ActewAGL), and the NSW gas distribution network (Jemena Gas Networks), for the regulatory period 1 July 2014 to 30 June 2019.

The AER found the five networks were operating less efficiently than comparable networks, and their owners had proposed excessive rates of return and tax allowances. The five businesses sought review of the AER's decisions, seeking to recover around $5 billion in additional revenue from consumers.

The Tribunal in February 2016 found in favour of the businesses in areas relating to operating expenses, taxation costs and debt costs—and directed the AER to remake its revenue decisions. The AER then appealed to the Federal Court for a judicial review of the Tribunal's decisions.

8 AER, *Consumers win as Full Federal Court confirms AER revenue decision for SA Power Networks*, media release, 18 January 2018.

Figure 3.6
Timeline of AER revenue decisions for NSW and ACT



In 2017 the Full Federal Court upheld the Tribunal's findings in relation to the networks' operating expenses and debt costs, and ordered the AER to remake the five revenue decisions. The Productivity Commission reported the Tribunal's decision would allow the businesses to recover about $2.5 billion in additional revenue above what the AER had determined was efficient.[9]

The lengthy legal process posed unique challenges—in particular that the 2014–19 regulatory period to which the decisions applied was far advanced at the time

9 Productivity Commission, *Energy, shifting the dial: 5 year productivity review*, Supporting Paper no. 11, Canberra, August 2017, p. 76. The report quotes an estimate by Winestock, G and McDonald-Smith, A, 'Ausgrid, Endeavour, AGL, Jemena score win in $5b NSW case', *Australian Financial Review*, 26 May 2017.

of the remittal. Additionally, the AER's remaking of the 2014–19 decisions overlapped the early stages of the next regulatory reset for the five networks (which take effect on 1 July 2019).

The prolonged legal process led to significant over-recovery of revenue by the five networks during 2014–19. To manage price uncertainty for energy consumers, the AER accepted enforceable undertakings from the five businesses covering the three years to 30 June 2019, limiting rises in distribution charges to changes in the CPI.

The AER also worked with the Australian Energy Market Commission (AEMC) on a rule change allowing revenue impacts arising from the remittals to be 'smoothed' and recovered from customers over both the current regulatory period and the next period starting 1 July 2019.

In August 2017 the AER convened a stakeholder meeting to discuss resolving the remittal matters in a manner consistent with the long term interests of consumers. It also published consultation papers on its approach to remaking the operating expenses and debt costs in the decisions.

By August 2018 all four electricity businesses submitted new regulatory proposals addressing outstanding issues for the 2014–19 period. The AER made final decisions on the Essential Energy and Endeavour Energy proposals in May and September 2018 respectively. Each business developed its proposal in close consultation with key stakeholders, including Energy Consumers Australia, Energy Users Association of Australia, Public Interest Advocacy Centre, and the AER's *Consumer Challenge Panel*. The AER published a draft decision on the revised Ausgrid proposal in November 2018.

The proposals largely adopted the AER's original 2015 decision, plus up to $110 million in additional revenue. Any revenues recovered above the approved amounts will be returned to customers through lower charges in the next regulatory period (2019–24).

The AER found the proposals were consistent with its forecasts of operating expenditure and debt costs in light of the information before it in 2018. Since the original decisions, each business embarked on reforms to reduce their operating costs to levels consistent with those decisions, without compromising the quality, safety, reliability and security of supply on their networks. Previously contentious legal issues relating to financing costs and determining the cost of debt had also been clarified by recent legal cases.

The 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 allowed a timely resolution of an unusually lengthy process, and so provided certainty and price stability to consumers.

The AER in September 2018 published a draft decision to accept Evoenergy's new proposal for 2014–19 for the ACT distribution network. The AER found Evoenergy had consulted constructively with stakeholders and its proposal was consistent with the AER's cost forecasts. The draft decision would allow Evoenergy to earn revenues up to $26 million above the level approved in the AER's original 2015 decision. These additional revenues mostly cover efficient redundancy costs that Evoenergy has incurred since the 2015 decision to meet operating expenditure targets.

3.6 Refining the regulatory approach

The AER in 2011 proposed reforms to the energy rules to ensure customers pay no more than necessary for a safe, reliable supply of energy. The AEMC in November 2012 implemented several reforms—allowing wider use of benchmarking to assess network costs and introducing new incentives for network efficiency. The reforms also require network businesses to engage more closely with their customers to develop revenue proposals that better meet their needs.

The AER developed guidelines and schemes to apply the reforms. Due to the length of the regulatory cycle and the need for extensive consultation on implementation guidelines, the reforms first applied to decisions taking effect in 2015. They have been progressively applied to each network as it comes up for review, and by 2020 will apply to all networks.

Regulatory reform is ongoing. The AER continues to streamline its approach to benchmarking network businesses. In late 2017 it launched a review of operating environment factors unique to particular networks that may impact their measured efficiency data. Then in 2018, it reviewed the approach to setting rates of return for network businesses, and whether the approach to setting taxation allowances for network businesses needs reform (section 3.12.2 and box 3.2).

A critical focus in 2018 was on the quality of engagement by network operators with their customers and the AER (section 3.6.2). There is also ongoing work to improve incentive schemes and guidelines, such as new demand management incentives launched in late 2017 (section 3.11.5).

More generally, the AER is pursuing opportunities to remove contestable services—such as metering—from economic regulation to support the development of competitive markets. Its work in this area included new ring-fencing guidelines to enforce the separation of regulated service delivery from the supply of contestable services (section 3.7.1).

Box 3.2 Review of regulatory taxation

In 2018 the AER investigated whether some energy network businesses are being overcompensated for their corporate tax liabilities, resulting in consumers paying more than necessary for energy services.

We set revenues so energy networks can recover their expected costs, including their tax costs. In calculating expected tax costs, we have regard to expected taxable revenue, tax expenses (depreciation, interest, operating expenses) and the corporate tax rate. We use an incentive approach—a network that keeps its actual tax costs below expected costs can retain part of the benefit for the remainder of the regulatory period. But if actual tax paid is above the expected amount, the network bears the loss.

We estimated that regulated energy networks would pay around $5 billion in tax across the five year period from 2012–17 (in 2017 dollars). But the Australian Taxation Office (ATO) notified that privately owned energy networks have been paying less tax, and government owned networks paying more tax, than estimated by our modelling.[10] The ATO noted this discrepancy may relate to differences in ownership structure, gearing (debt) and depreciation methods. We are exploring whether changes to the regulatory model or the energy rules themselves are needed to address this issue, as part of our review of regulatory tax.

In our November 2018 discussion paper, we found a material difference between our regulatory forecast of tax costs and actual tax payments made. We found some aspects of our regulatory approach may not reflect current efficient tax management practices and identified possible changes to incorporate these practices.[11]

10 Australian Taxation Office, *Note to Australian Energy Regulator, Indicative comparative analysis of the AER electricity distribution tax allowance and tax payable*, 10 April 2018.

11 AER, *Review of regulatory tax approach, Discussion paper*, November 2018.

3.6.1 Aligning business and consumer interests

The regulatory process is complex and often adversarial. In this environment, consumers find it challenging to have their perspectives heard, and difficult to assess whether a network proposal reflects their interests. To help consumers engage in the regulatory process, the AER publishes documents—including factsheets that simplify technical language—and holds public forums.

To engage more effectively with stakeholders, the AER established a *Consumer Challenge Panel* in 2013 to ensure consumer perspectives are properly voiced and considered. In September 2016 the AER appointed a new panel of experienced and highly qualified individuals with consumer, regulatory and/or energy expertise to continue to bring strong consumer perspectives to its decision making processes.[12]

Reforms launched in 2013 also sharpened focus on how effectively network businesses engage with their customers in shaping their revenue proposals. Powerlink and TasNetworks were among the first networks to start focusing on this issue.

The AER's 2017 revenue decisions for those networks found each business had developed their regulatory proposals in close consultation with their customers. This consultative work laid foundations for the AER to accept major elements of the proposals, including capital and operating expenditure forecasts. In 2018 the AER made similar findings of constructive engagement by ElectraNet with its customers.

Evidence of constructive engagement also enabled the AER to adopt a relatively expedited process for its 2018 draft decisions on the remittal processes for Essential Energy and Endeavour Energy. Stakeholders endorsed the efforts and goodwill shown by each business to develop proposals aligning their interests with those of customers.

SA Power Networks followed a similar path to develop a new regulatory proposal in 2018. It conducted research to understand customer sentiment and priorities, before engaging with its customers on price, reliability and resilience, and the network's evolution. Engagement methods included workshops, focus groups, and online engagement. In 2018 this engagement explored topics through 'deep dive' workshops. SA Power Networks

12 The panel's composition is published on the AER website at www.aer.gov.au/about-us/consumer-challenge-panel.

indicated it would seek further feedback ahead of lodging its regulatory proposal with the AER in January 2019.[13]

3.6.2 Early engagement models

Following the developments noted above, a number of businesses are experimenting with early engagement models to better reflect consumer interests and perspectives in framing their regulatory proposals. Early engagement offers potential to expedite the regulatory process, reducing costs for businesses and consumers. The AER is trialling one such approach—the New Reg—in partnership with Energy Networks Australia and Energy Consumers Australia (box 3.3).[14]

The New Reg involves a network business establishing an independent customer forum to collect consumers' views through research and engagement. The forum can negotiate agreement with the business on elements of its revenue proposal, and must justify positions it negotiates in a public report.

The AER participates from an early stage by approving engagement plans and processes, and ensuring the customer forum is equipped to navigate the complexities of a regulatory proposal. Additionally, the AER may advise on which issues are within scope for agreement. Matters such as the rate of return (which in future will be subject to a binding guideline (section 3.12.2) and reliability standards (which jurisdictions mandate) may fall outside the scope for negotiation, for example.

If early engagement achieves agreement between the business and its customers on key areas, and a regulatory proposal reflects that agreement, the AER would put significant weight on these outcomes in its decision making. The AER may expedite its regulatory assessment by undertaking a less detailed examination of areas upon which agreement was reached.

The AER is exploring innovative approaches to engagement across its work program. Recent examples include engagement on tariff structure reviews in NSW and in the development of new rate of return guidelines for network businesses.

13 AER, *Preliminary framework and approach—SA Power Networks, Regulatory control period commencing 1 July 2020*, March 2018.
14 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 and Approach Papers, March 2018.

Box 3.3 Trialling the New Reg model

AusNet Services, one of Victoria's five electricity distributors, launched an active trial of the New Reg model in 2018 to develop its upcoming revenue proposal for the regulatory period 2021–25.[15] In consultation with the AER and Energy Consumers Australia, AusNet Services established a customer forum consisting of a former state government minister, a former senior finance executive and board member at Yarra Valley Water, a consumer advocate, and a market and social researcher. Its first step was undertaking comprehensive engagement to understand its customers' concerns and preferences.

AusNet Services planned to release a draft for public consultation in 2018, including on issues agreed with the forum. It will continue to engage with its customer forum and the AER in shaping its revenue proposal until its formal lodgement in July 2019.

The AusNet Services trial and our consultation on it will inform our assessment of the New Reg model's effectiveness in enabling consumers' preferences to drive network decision making. The results will inform discussions about possible future changes to the energy rules. Broader consultation on the New Reg model will also continue throughout the AusNet Services trial. Learnings from the trial will inform the model's development.

3.7 Power of Choice reforms

Innovations in network and communications 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 customers make choices to voluntarily reduce their energy use in peak periods, it potentially delays the need for costly network investment.

Power of Choice reforms are being progressively rolled out to unlock the potential benefits of these changes. The reforms, many of which came into effect in 2017, include a market led rollout of 'smart' meters, supported by more cost reflective network pricing (section 3.7.1), and incentivising demand management as a lower cost alternative to network investment (section 3.11.5).

15 AusNet Services, www.ausnetservices.com.au/en/Misc-Pages/Links/About-Us/Charges-and-revenues/Electricity-distribution-network/Customer-Forum, accessed 19 June 2018.

3.7.1 Tariff structure reforms

Under traditional network tariff (price) structures, households and small businesses pay the same tariffs regardless of how and when they use energy. Some customers—such as those with airconditioners or solar PV systems—do not pay their full network costs under these structures, while other customers pay *more* than they should.

Reforms introduced in December 2017 require distribution businesses to move energy customers onto network tariffs more closely reflecting the efficient costs of providing the services they use. Distributors are phasing in the new structures. For the initial pricing period, most networks adopted a form of demand tariff. The NSW distribution businesses Ausgrid and Endeavour Energy introduced another form of cost reflective tariff (time-of-use tariffs).[16]

Retailers pay the new network charges initially, then decide whether to pass on those costs to customers and in what form. Most networks are offering the new cost reflective structures on an opt-in basis (that is, a customer may choose to adopt the new pricing, but otherwise stays on the old flat price structure). But some networks are making the tariffs mandatory for new customers, or those with smart meters.

Around 12 per cent of small customers in 2018 were on new tariff structures,[17] with most of these on time-of-use tariffs. In those networks with opt-in arrangements, very few small customers have elected to move voluntarily to a new tariff structure.

Distributors are required to progress towards full cost reflective pricing through their tariff structure statements, which the AER examines within the revenue determination process. This progress may include:

- simplifying tariff offerings
- designing tariffs that more closely reflect how customer use affects the network's costs
- applying an opt-out approach requiring customers to move to a new tariff unless they elect not to
- integrating network pricing with broader management policies (such as network planning and demand management).

Limited penetration of smart meters for residential and small business customers is a barrier to implementing cost reflective network tariffs outside Victoria. Smart meters measure electricity use in half hour blocks, allowing energy customers to monitor their energy use.

At June 2018 30 per cent of customers in the NEM had metering capable of supporting cost reflective tariffs. While over 97 per cent of Victorian customers had access to a smart meter, penetration in other regions was around 5 per cent of customers. Another 6 per cent of customers in these regions (mostly in NSW) had access to an interval meter providing half hourly reading of consumption but without remote reading and connection capabilities.[18]

Network businesses traditionally provided electricity meters on residential premises. But this arrangement limits competition and consumer choice. It may also discourage investment in metering technology to support the uptake of new and innovative energy products. Changes promoting competition in the provision of metering services took effect in December 2017 to address this barrier.

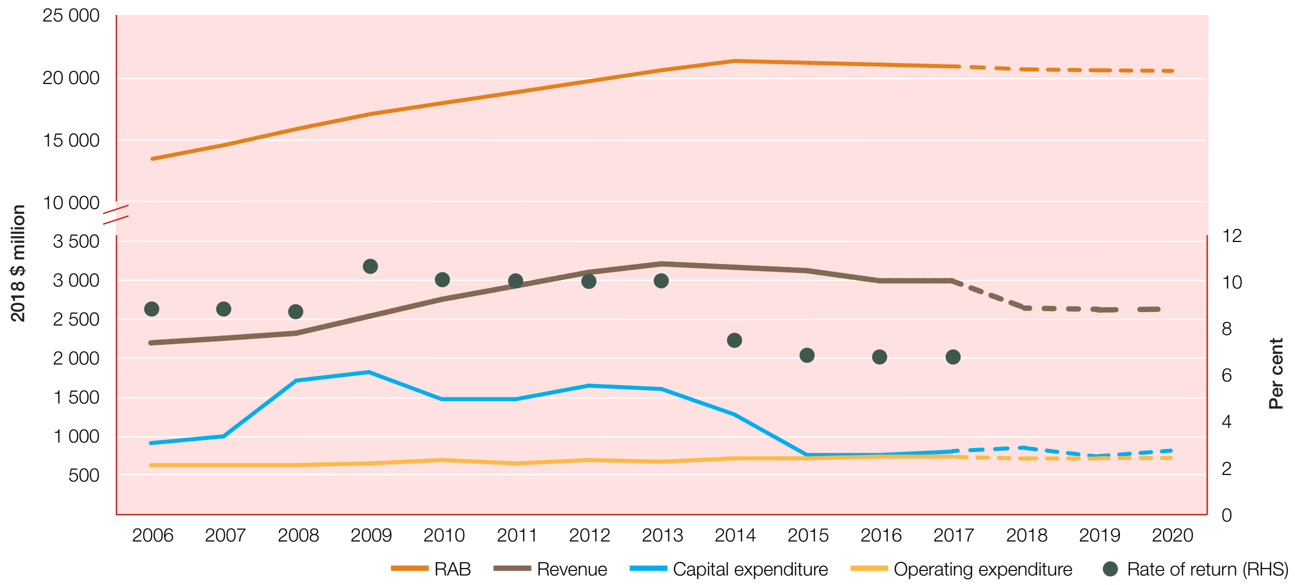
Where a network business offers metering or other services in a contestable market, robust ring-fencing must be in place to ensure the business competes fairly with other providers. The AER launched new ring-fencing guidelines requiring distribution networks to separate their regulated network services (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, and prohibit a regulated business from engaging in a potentially contestable activity.[19]

Distribution networks were required to comply with the ring-fencing rules by January 2018. But during the first six months of operation, the AER raised numerous compliance concerns with network businesses. In most cases, these concerns related to the businesses failing to properly train staff or implement appropriate systems.[20]

16 Demand tariffs charge a customer based on their maximum point-in-time demand during pre-defined periods linked to peak system demand. These charges can be applied in addition to usage and supply charges. Time-of-use tariffs apply different pricing to electricity usage in peak and off-peak times. Both tariffs are designed to encourage customers to minimise their usage at peak times.
17 ACCC, *Retail Electricity Pricing Inquiry—Final Report*, p. 177.
18 AER estimates based on information gathered through the ACCC Retail Electricity Pricing Inquiry.
19 The ring-fencing reforms also apply to demand management incentives (section 3.11.5).
20 AER, *Quarterly Compliance Report. National Electricity and Gas Laws*, 1 April–30 June 2018.

Figure 3.7
Transmission revenues and key drivers



RAB, regulatory asset base.

Note: Revenue, capital expenditure, operating expenditure and RAB data are actual outcomes to 2017, and forecasts for 2018, 2019 and 2020. RAB is actual closing data at end of relevant year. Data is shown for relevant regulatory years on an end of year basis. Networks report on a 1 July to 30 June basis, except in Victoria, where they report from 1 April–31 March basis. All data is CPI adjusted to June 2018 dollars. Rates of return are WACC forecasts in AER revenue decision and Australian Competition Tribunal decisions for transmission networks.

Source: AER estimates derived from economic benchmarking RIN responses, AER revenue decisions, Australian Competition Tribunal decisions and AER modelling.

3.8 Headline trends in AER decisions

AER revenue decisions over the past 12 years show two distinct trends—rapid revenue and investment growth for several years, following by a significant downturn in both. Similar trends are apparent across transmission and distribution, although transmission revenues peaked earlier (2013) than distribution (2015), and the decline in transmission revenues was more gradual (figures 3.7 and 3.8).

AER forecasts indicate network revenues will plateau over the period 2018–20. An increase in forecast capital expenditure will raise the regulatory asset base (RAB) and generate slightly positive revenue growth in the distribution sector.

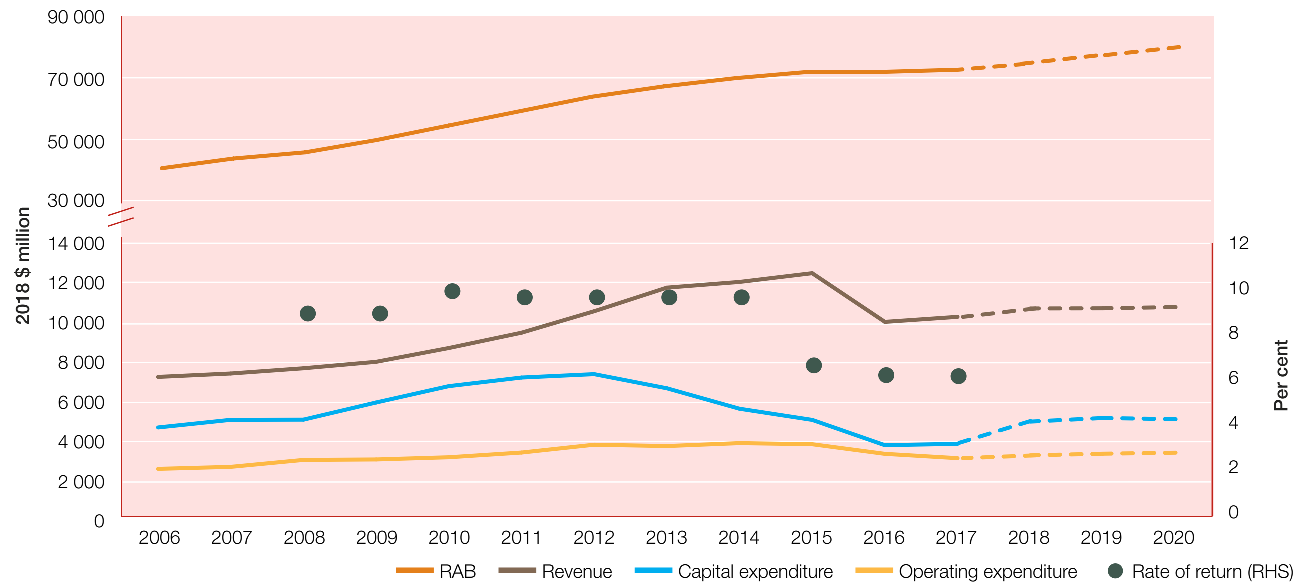
Changes in rates of return have significantly driven these revenue trends. Rates of return set in Tribunal decisions peaked at over 10 per cent in 2011, following a period of financial market instability. By 2017 they were running at just over 5 per cent.

A surge in network investment from 2006–12 also added to the RAB. But weaker electricity demand caused network businesses to delay or postpone capital projects after 2012, stemming further rapid growth in the RAB (especially in transmission, where the asset base shrank after 2014).

Despite a shift to more moderate operating conditions from around 2012, the five year regulatory cycle meant lower investment and rates of return only flowed through to revenue after a significant lag. Returns will also continue to be paid on assets added in those peak years for the duration of their economic life, which may run to decades.

Operating expenditure correlates less closely with market conditions than other drivers, and shows relatively stable trends. Capital expenditure almost trebled operating expenditure in 2009, but the two were almost comparable in scale by 2015. Since then, operating expenditure has also eased, as network businesses (especially distributors) implement efficiency programs. Reforms to the regulatory framework also began to impact outcomes from 2015 (section 3.6).

Figure 3.8
Distribution revenues and key drivers



RAB, regulatory asset base.

Note: Revenue, capital expenditure, operating expenditure and RAB data are actual outcomes to 2017, and forecasts for 2018, 2019 and 2020. RAB is actual closing data at end of relevant year. Data is shown for relevant regulatory years on an end of year basis. Networks report on a 1 July to 30 June basis, except in Victoria, where they report on a calendar year basis. All data is CPI adjusted to June 2018 dollars. Rates of return are WACC forecasts in AER revenue decision and Australian Competition Tribunal decisions, for distribution networks.

Source: AER estimates derived from economic benchmarking RIN responses, AER revenue determinations, Australian Competition Tribunal decisions and AER modelling.

The following sections more closely examine trends in network revenues and the factors driving them.

3.9 Electricity network revenues

Electricity networks in the NEM earned just under $13 billion in 2017, a 2 per cent rise on the previous year.[21] But revenues were significantly lower than the peaks recorded a few years earlier (figure 3.9):

- Transmission businesses earned $2.9 billion in 2017, which was 7 per cent less than when revenues peaked in 2013.
- Distribution businesses earned $9.9 billion in 2017, which was 18 per cent less than when revenues peaked in 2015.

21 Data refers to actual outcomes for the 2017 regulatory year adjusted to 2018 dollars. The assumptions are explained in more detail in the notes to figures 3.7 and 3.8.

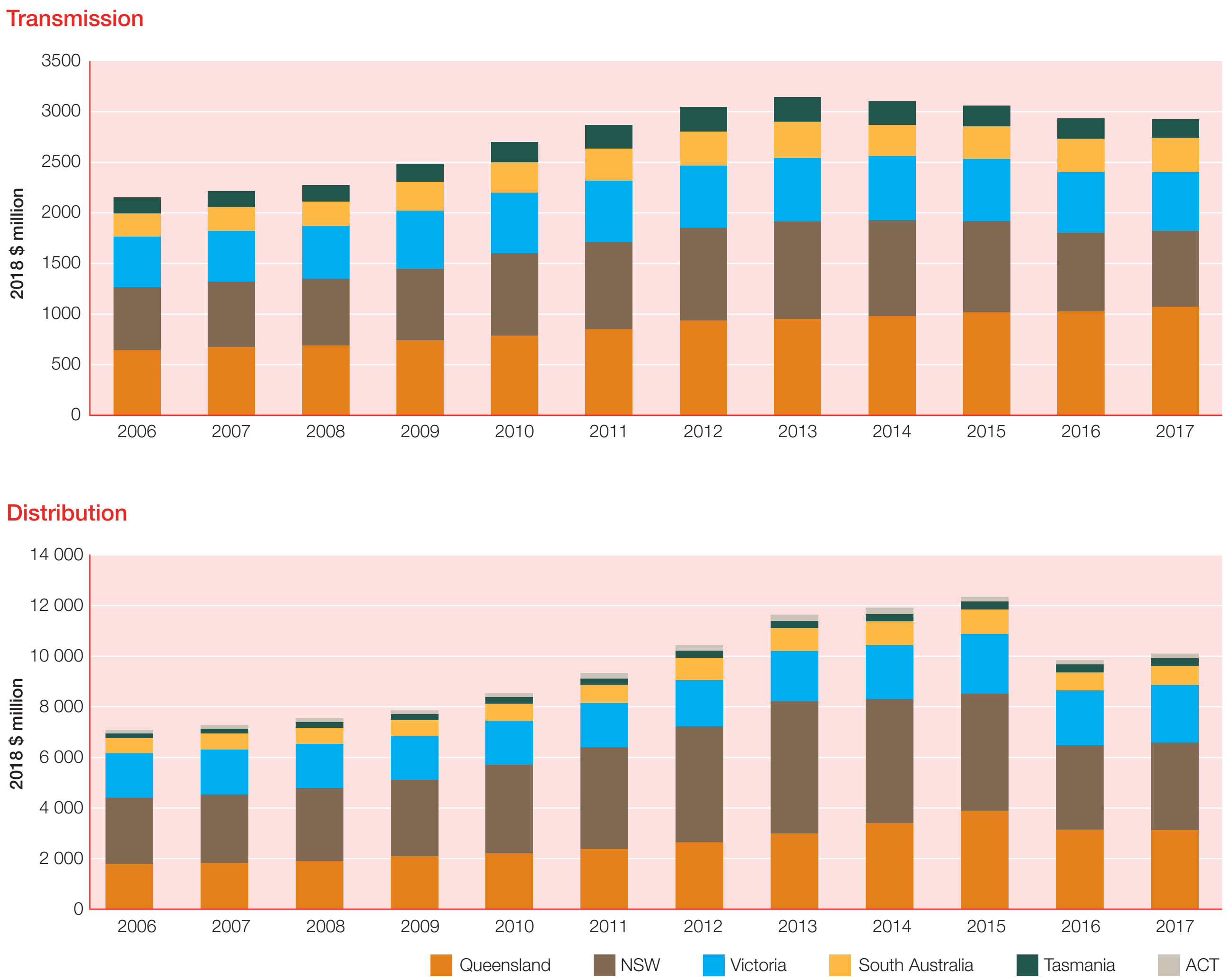
3.9.1 Recent outcomes

All AER decisions in 2017 and 2018 approved lower revenues than in previous regulatory periods (figure 3.10). Network revenues are forecast to be around 16 per cent lower on average in current regulatory periods (at 1 July 2018) than in previous regulatory periods. Lower revenues are forecast for every transmission network in the NEM and for every distribution network outside Victoria.

Lower commercial rates of return have been a key driver of lower network revenues. Weaker electricity demand has also eased network investment, stemming the previously rapid growth in network assets and associated capital costs (depreciation and returns on assets). Additionally, networks are implementing efficiencies to better control their operating costs. Lags in the regulatory cycle and lengthy legal appeals for some networks mean the trend towards lower revenues has varied between jurisdictions.

This trend of weakening network revenues, combined with growing customer numbers, is translating into lower network

Figure 3.9
Electricity network revenues



Note: Actual outcomes, CPI adjusted to June 2018 dollars. Assumptions set out in notes to figures 3.7 and 3.8.
Source: Economic benchmarking RIN responses, AER regulatory decisions and regulatory proposals from businesses.

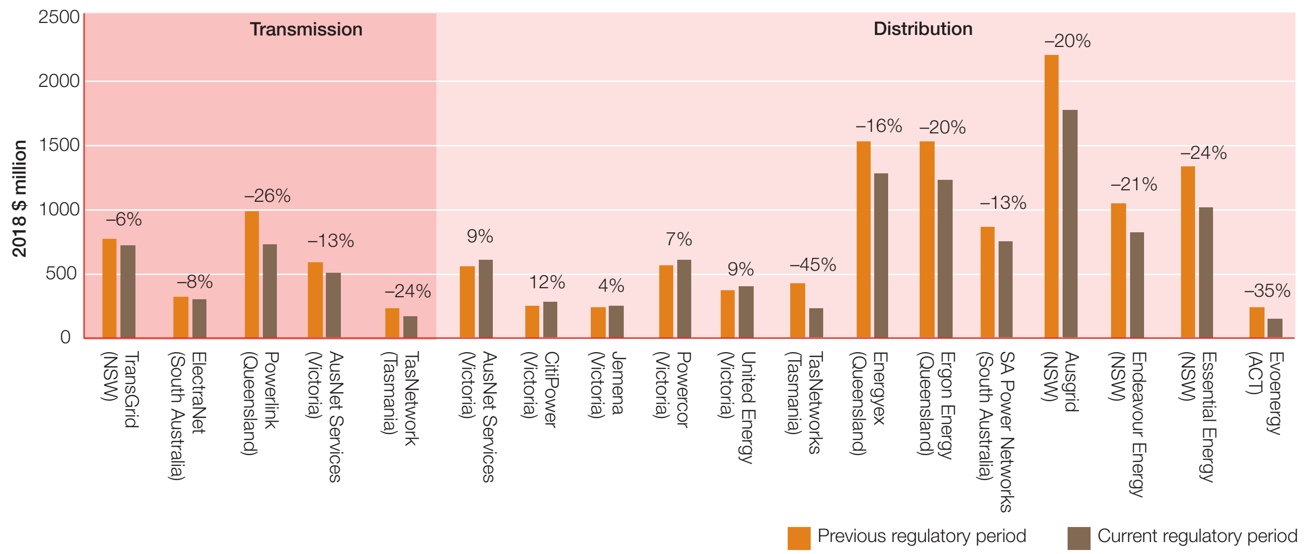
charges in retail energy bills for most networks (figure 3.11). This reduction is helping mitigate some of the upward pressure on retail energy bills in recent years from rising wholesale electricity costs.

Victoria's distribution networks differ from the industry trend, with revenues in the current period forecast at 4–12 per cent higher than in the previous period. Increases were driven by forecasts of rising operating costs and replacement expenditure (sections 3.11 and 3.13). These outcomes partly reflect that the Victorian networks achieved a number of operating efficiencies earlier than networks elsewhere, as well as pipeline investment in new housing estate projects.

3.9.2 Longer term trends

The longer term saw a steep rise in network revenues from 2006 until around 2015. Changes to the energy rules in 2006 led to rapid growth in network investment at a time of globally high interest rates, compounding the impact on revenues. Operating expenditure also rose, with 45 per cent

Figure 3.10
Network revenues—change from previous period



Note: Revenues are smoothed annual averages. Actual outcomes for previous regulatory period, and forecasts for current period. Percentages represent the revenue change between regulatory periods. Forecast updates may result in some outcomes varying from those previously reported.
Current regulatory periods at 1 July 2018 (see table 3.1 for transmission and table 3.2 for distribution). Determinations in each sector appear in chronological order of the decision dates (listed in tables 3.1 and 3.2).
Source: AER economic benchmarking RINs; AER regulatory determinations and AER modelling.

real growth from 2006–2014, putting further pressure on revenues.[22]

- At the peak of this growth, network revenues rose by over 9 per cent each year in real terms between 2009 and 2013. This growth was the main cause of escalating retail electricity prices over this period, with network charges making up 43 per cent of retail customers' bills.

Many AER decisions also faced legal challenges in this period (section 3.5.1), often resulting in the Tribunal or Full Federal Court further increasing network revenues (of the 38 appeals in this period, none reduced revenues).

Revenues rose higher in Queensland and NSW than elsewhere. In Queensland, revenues more than doubled between 2006 and 2015. In NSW, revenues rose by 90 per cent from 2006–13. Revenue growth was less dramatic in Victoria, at 32 per cent from 2006–15.[23] A key cost driver in Queensland and NSW was stricter reliability standards imposed by state governments, which required new investment and operating expenditure to meet targets.

Some of the cost pressures facing network businesses began to ease when electricity demand from the grid began to decline, causing new investment to be scaled back from 2013. The changing demand outlook coincided with government moves to allow network businesses greater flexibility in meeting reliability requirements.

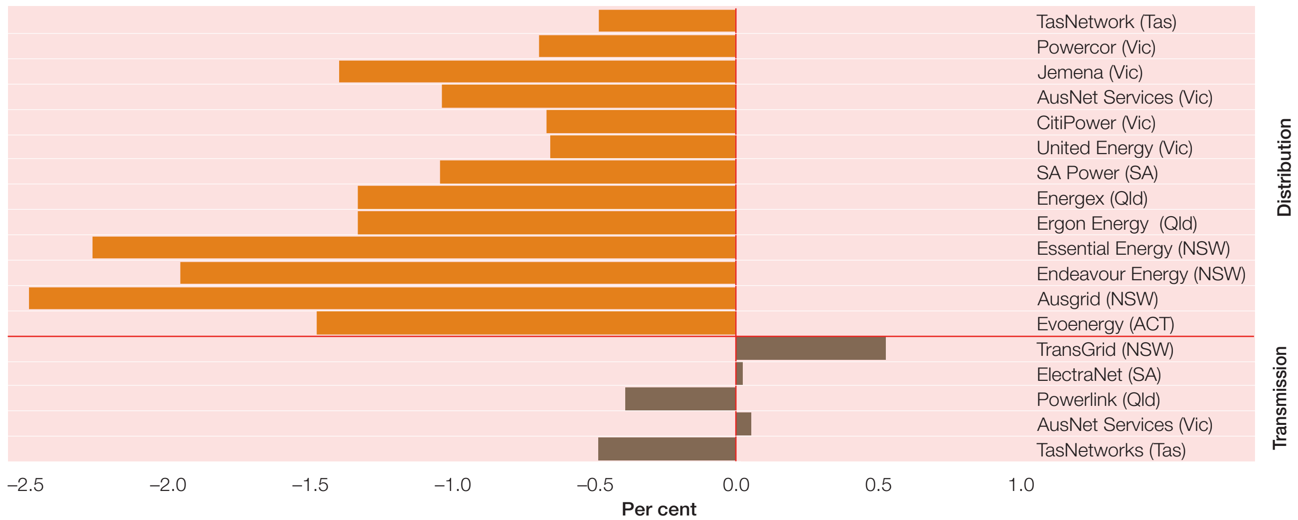
The financial environment also improved from 2013, easing borrowing and equity costs. In combination, these factors reduced the revenue needs of network businesses, with the impact flowing through to customers on a lagged basis as new regulatory cycles took effect. However, legal appeals on some AER decisions delayed the benefit of this shift to customers.

Reforms to the energy rules phased in from 2015 also began to impact network revenues. The reforms, which more explicitly linked network costs to efficiency factors, encouraged many network businesses to rationalise their operating costs.

While network revenues are generally moving lower, network costs will continue to reflect over-investment from 2006–13 for the economic lives of those assets—which can 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.[24] The Australian Competition

22 ACCC, *Retail Electricity Pricing Inquiry—Final Report*, June 2018 p. 64
23 ACCC, *Retail Electricity Pricing Inquiry—Final Report*, June 2018, p. 61 and figure 2.33.
24 Grattan Institute, *Down to the wire—A sustainable electricity network for Australia*, March 2018.

Figure 3.11
How AER decisions affect customer bills



Note: Estimated impact of latest AER decision on network component of a residential electricity bill for a customer using 6500 kilowatt hours of electricity per year. Revenue impacts are nominal and averaged over the life of the current decision. The data only accounts for changes in network charges. Changes in other bill components are not reflected. Outcomes will vary among customers, depending on energy use and network tariff structures. The outcomes for NSW and ACT reflect the AER's original 2015 decisions, which were later varied by the Australian Competition Tribunal and Full Federal Court.

Source: AER revenue decisions and additional AER modelling.

and Consumer Commission (ACCC) supported this position, particularly for government owned networks in Queensland, NSW and Tasmania.[25]

Consumer groups and some industry observers remain concerned the regulatory framework enables network businesses to earn excessive profits, given the low market risks they face. To help evaluate this argument, the AER in 2018 began publishing new profitability data that allows stakeholders to compare the returns earned by each business (section 3.12.1).

3.10 How network charges impact electricity bills

Electricity network charges make up around 43 per cent of a residential customer's energy bill (figure 1.x). Most of these charges are distribution network costs.

3.10.1 Distribution charges

Current AER decisions reduced distribution charges in residential energy bills by around 1–2.5 per cent per year in all states and territories (figure 3.11). The falls mostly accrue in the first or second years of a regulatory period, followed by stable prices or small price movements (occasionally, small increases) in later years.

The reduction in network charges reflects a combination of factors noted previously—lower finance costs, weaker electricity demand requiring less 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.

The significant savings of up to 2.5 per cent per year for NSW and ACT energy customers reflect outcomes in the AER's 2015 decision for those networks. But those savings were partly set aside by the Tribunal. During the lengthy legal and remittal processes that followed, the AER accepted enforceable undertakings on network prices covering the three years to June 2019. The undertakings indexed network charges to the CPI (section 3.5.2).

3.10.2 Transmission charges

Current AER decisions reduced network charges in Queensland and Tasmania, but allowed increases in NSW, Victoria and South Australia. The Queensland and South Australian networks were among the first businesses in the NEM to develop regulatory proposals in close consultation with their customers (section 3.6.1).

25 ACCC, *Retail Electricity Pricing Inquiry—Final Report*, June 2018.

The TransGrid (NSW) decision in 2018 followed a more adversarial process in which the AER required significant changes to the network's proposals. The decision is expected to raise residential energy bills by around 0.5 per cent—the highest for any current revenue decision. This outcome partly reflects over-investment by TransGrid in previous regulatory periods, which raised the network's asset base, upon which depreciation costs and returns to investors continue to be calculated.

3.11 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 between networks and depend on a network's age and technology, load characteristics, the demand for new connections, and reliability and safety requirements. Some investment is needed to replace old equipment as it wears out or becomes technically obsolete. Other investment may be made to augment (expand) a network's capability in response to changes in electricity demand.

As part of the revenue determination process, the AER forecasts a network's efficient investment requirements over the upcoming period. This approved investment gets added to the network's regulated asset base.[26] As the RAB grows, the returns paid to shareholders and lenders who fund those assets also rises—this cost is passed on to customers. As some network assets have an asset life of up to 50 years, network investment will impact on retail energy bills long after the investment is made.

Network operators receive a guaranteed return on their RAB and so may have incentives to over-invest or 'gold plate' the networks to maximise those returns, particularly where their allowed rate of return is higher than their actual financing costs. Previous versions of the energy rules allowed for significant over-investment in network assets, which partly drove the sharp rise in network revenues from 2006–15 (section 3.9.2).

But reforms to the energy rules introduced incentives for efficient investment. Under the reforms, which have progressively applied since 2015, the AER can remove inefficient investment from a network's asset base where a network over-spends its allowance, so consumers do not have to pay for it.

The AER also launched a *capital expenditure sharing scheme* (CESS), which first applied in 2015. If a network business manages its investment program efficiently and under-spends against its forecast, it can 'keep the difference' between its forecast and actual capital costs[27] for the remainder of the regulatory period. However, it must bear the difference as lower profits if it over-invests. In the following regulatory period, a network business must share efficiency savings with its customers by passing on 70 per cent of savings as lower network charges. The business may retain the remaining 30 per cent of savings.

The scheme poses risks that require careful management. It encourages businesses to inflate their original investment forecasts. To manage this, the AER closely scrutinises whether proposed investments are efficient at the time of each reset. Additionally, it may incentivise a network business to earn a bonus by deferring critical investment needed to maintain the network's safe and reliable operation. The scheme is balanced by a separate incentive scheme to maintain service quality in ways that customers value (section 3.15.5).

3.11.1 Investment activity in electricity networks

Electricity networks in the NEM invested $4.5 billion in network assets in 2017, a 2.5 per cent rise on the previous year.[28] Around 83 per cent of that investment was made by distribution networks, with transmission networks investing the remaining 17 per cent.

While investment rose slightly in 2017, it was significantly below the peaks recorded a few years earlier (figures 3.7 and 3.8):

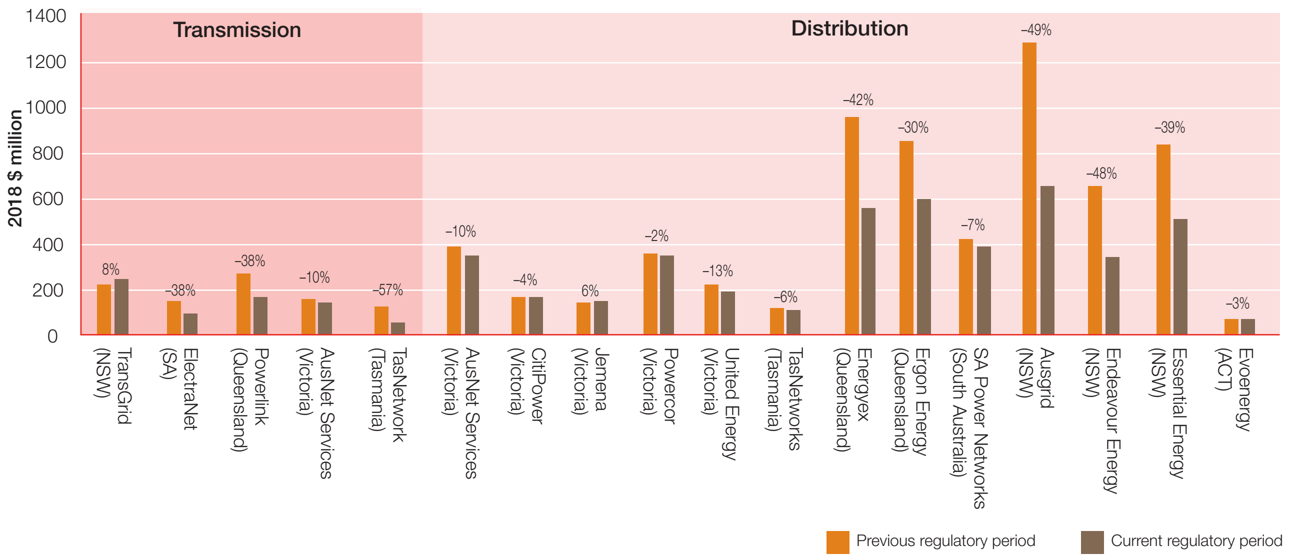
- Transmission businesses invested over $760 million in network assets in 2017—56 per cent lower than in 2009, when transmission investment peaked.
- Distribution businesses invested $3.7 billion in network assets in 2017—48 per cent lower than in 2012, when distribution investment peaked.

26 For example, if a network has an opening asset of $48 billion, and approved investment during the year of $5 billion, the asset base at the end of the year rises to $53 billion. If depreciation of assets due to old age and technical obsolescence is $3 billion, this is then subtracted to give a closing asset base of $50 billion.

27 The capital costs factored into a network's forecast revenue are: the return on capital needed to fund assets; and asset depreciation costs. If a network invests below forecast, these capital costs are reduced. The incentive scheme allows the business to retain these savings for the remainder of the regulatory period.

28 The assumptions underpinning data in this chapter are explained in the notes to figures 3.7 and 3.8. Unless otherwise stated, data refers to actual outcomes adjusted to 2017 dollars.

Figure 3.12
Network investment—change from previous period



Note: Smoothed annual averages, 2018 dollars. Actual outcomes for previous regulatory period, and forecasts for current period. Percentages represent the change between regulatory periods. Revisions may result in some outcomes varying from those previously reported.

Current regulatory periods at 1 July 2018 (see table 3.1 for transmission and table 3.2 for distribution). Determinations in each sector appear in chronological order of the decision dates (listed in tables 3.1 and 3.2).

Source: AER economic benchmarking RINs; AER regulatory determinations and AER modelling.

Current decisions

AER decisions in place at 1 July 2018 forecast network investment being 31 per cent lower on average than in the previous regulatory periods (figure 3.12). Across the NEM, only two of 18 current decisions approved higher investment than in the previous period.[29]

In distribution, the largest cuts were for government owned networks in Queensland (where investment is forecast to fall by 30–42 per cent) and NSW (falls of 39–49 per cent). Only one network (Jemena in Victoria) is forecast to increase investment.

The pattern is more varied in transmission, with the government owned Powerlink (Queensland) and TasNetworks recording substantial reductions. The privately owned ElectraNet (South Australia) also recorded a substantial fall, with the AER in 2018 approving some of its investment proposals only on a contingent basis (subject to future trigger events). TransGrid (NSW) is the only transmission network forecast to increase its investment in the current regulatory period (see figure 3.12).

29 Excludes decisions on transmission interconnectors.

Investment decisions in 2018

The AER in 2018 made final revenue decisions on three transmission networks—ElectraNet in South Australia, TransGrid in NSW and the Murraylink interconnector between Victoria and South Australia. The decisions cover the five year regulatory period 1 July 2018 to 30 June 2023. All three networks forecast the need for major new investment projects in the upcoming period.

ElectraNet's proposal was its first since a 'black system' event in South Australia on 28 September 2016 resulted in a state wide loss of electricity. While the AER lowered investment by 38 per cent compared with the previous regulatory period, it did accept a 13 per cent rise in investment in projects to enhance the network's security and resilience to extreme weather events.

The AER's TransGrid decision scaled back the network's proposed investment by around 20 per cent. Despite this, approved investment was still 8.5 per cent higher than in the previous period, partly to finance TransGrid's proposed 'Powering Sydney's Future' project. While the AER's draft decision rejected that proposal, its final decision accepted a revised proposal with lower costs, on condition that independent project oversight ensures it benefits consumers.

The Murraylink decision approved a $25 million upgrade to replace an aging control system to enable a safe and secure electricity supply to South Australia. This represents the first major capital expenditure for the interconnector in some time.

Additionally, the AER approved a number of major projects on a contingent basis, after finding their need, cost and scope was uncertain. The quantum of these projects is substantial—almost $5 billion across the three networks, which almost tripled the $1.7 billion of approved investment.

The networks can ask the AER to reassess whether these projects are prudent and efficient if certain trigger events occur. TransGrid proposed nine contingent projects, totally around $4 billion of investment. The projects include connecting large scale renewable generation such as Snowy 2.0 to the network, and a new transmission interconnector between NSW and South Australia. ElectraNet's contingent projects include a $950 million proposal to address power system security and reliability.

Longer term investment trends

The longer term saw a rapid escalation in network investment from 2006 until around 2012, which often outpaced forecasts (figure 3.13).

Changes to the energy rules in 2006 spurred much of this growth.[30] Governments and the AEMC changed the rules to incentivise investment, to address concerns that network investment was not keeping pace with projected growth in electricity demand at the time. More stringent reliability standards imposed by state governments in NSW and Queensland also contributed to this growth by requiring new investment to meet the stricter targets.

But weakening electricity demand began to reverse this trend from 2013. Many projects were postponed or abandoned when it became clear 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.

Investment levels further eased from 2015 when AER reforms protecting consumers from funding inefficient network projects began to apply. Additionally, the CESS scheme offered financial incentives for network businesses to invest below forecast levels.

30 ACCC, *Retail Electricity Pricing Inquiry—Final Report*, June 2018, p. 111; Reeves, A, Consumer involvement in energy regulation, speech, 23 May 2013; Productivity Commission, *Electricity Network Regulatory Framework*, Inquiry report, 9 April 2013.

These trends are also evident on a per customer basis. Distribution network investment per customer peaked in 2012, then sharply declined. Transmission network investment per customer peaked in 2009—three years earlier than in distribution. Overall investment fell sharply from 2013–16, before recovering slightly in 2017. By 2017 per customer investment was 49 per cent below the peak for distribution businesses, and 56 per cent below the peak for transmission businesses.

Impacts on the asset base

Capital investment increases a business's regulatory asset base, upon which it earns returns. Escalating investment from 2006 inflated RABs in the network sector, with a 70 per cent rise in real terms over the nine years to 30 June 2015 (figure 3.14).

Weaker investment is reflected in reduced RAB growth per customer in distribution (from 2015) and transmission (from 2014), stemming a decade of continuous rapid growth. From 2015 to 2017, RAB per customer in the NEM fell 1–2 per cent per year (figure 3.15).

3.11.2 The changing composition of investment

While annual investment in electricity networks has been declining for several years, the *composition* of that investment has changed markedly.

A network business's capital expenditure program mostly relates to:

1. 'growth' (augmentation) expenditure to expand capacity to cope with forecast rising demand
2. replacement expenditure for aging or technologically obsolete assets that have reached the end of their economic life.

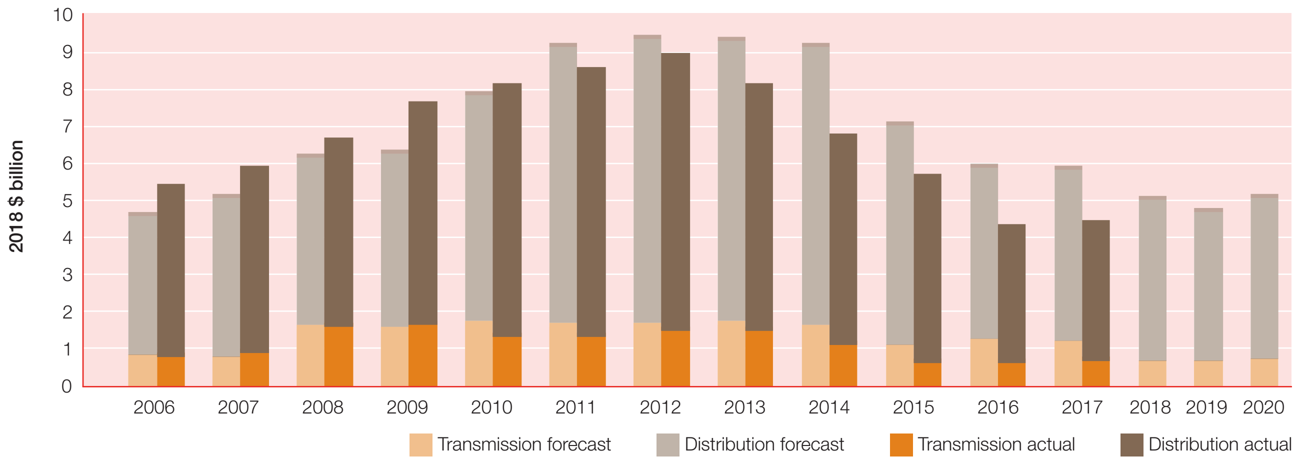
Other categories of capital expenditure include investment supporting new connections (such as new substations), non-network assets (such as motor vehicles) and capitalised overheads such as IT.

For most network businesses, growth expenditure was traditionally the main component of investment. In 2009, it accounted for 63 per cent of all transmission investment and 42 per cent of distribution investment.

But weakening electricity demand along with less stringent reliability obligations led many network owners to shelve or delay growth plans over the following years. By 2017 growth investment had shrunk to 9 per cent of transmission investment and 26 per cent of distribution investment. In

Figure 3.13

Network investment—forecast and actual



Note: Actual outcomes for relevant year on an end of year basis, 2018 dollars. Assumptions set out in notes to figures 3.7 and 3.8.

Source: AER estimates derived from Economic benchmarking RIN responses, AER revenue determinations, and AER modelling.

dollar terms, growth investment declined from over $3 billion in 2009 to just over $1 billion in 2017 (figure 3.16).[31]

In contrast, replacement expenditure has remained relatively steady at around $1.5 billion. But as a proportion of the shrinking total investment pool, replacement investment has risen strongly. In transmission, replacement investment rose from 27 to 69 per cent of the investment pool from 2009 to 2017. In distribution, it rose from 24 to 38 per cent of investment over the same period.

3.11.3 Regulatory tests for efficient investment

The AER assesses a network's efficient investment requirements as part of the revenue reset process. Additionally, a network business must conduct a cost–benefit analysis (a regulatory investment test) for each project to ensure it is efficient. The analysis must include an evaluation of the investment proposal against viable alternatives, including non-network options such as electricity generation. The business must give due consideration to alternatives, before identifying the best way to address the needs on their network. Public consultation is required as part of the assessment.

The AER monitors businesses' compliance with the tests. It also resolves disputes over whether a network business has properly applied a test. At 1 March 2018 the AER had reviewed or monitored 18 applications of the Regulatory Investment Test for Transmission (RIT–T), 17 applications of the Regulatory Investment Test for Distribution (RIT–D) and resolved one RIT–D dispute, since the tests were introduced.[32]

The Energy Users Association of Australia (EUAA) notified a dispute in July 2018 over Ausgrid's application of a RIT–D test to an investment proposal in the Sydney Central Business District. The dispute concerned Ausgrid's estimated value of customer reliability (VCR), which EUAA claimed was significantly higher than an estimate TransGrid recently applied in a cost–benefit analysis for a similar project. The AER found the choice of VCR estimate would not materially impact the ranking of project options, but was critical of Ausgrid's cost–benefit analysis and the lack of transparency in its consultation process.[33]

Until 2017 the regulatory investment tests only applied to growth investment, which in recent years accounted for the bulk of network investment. But the composition of network investment is evolving, with replacement expenditure overtaking growth investment in most networks (section 3.11.2). Recognising this shift, the AER in June 2016 proposed widening the scope of regulatory investment tests to also include replacement investment—including asset refurbishment and de-rating decisions.

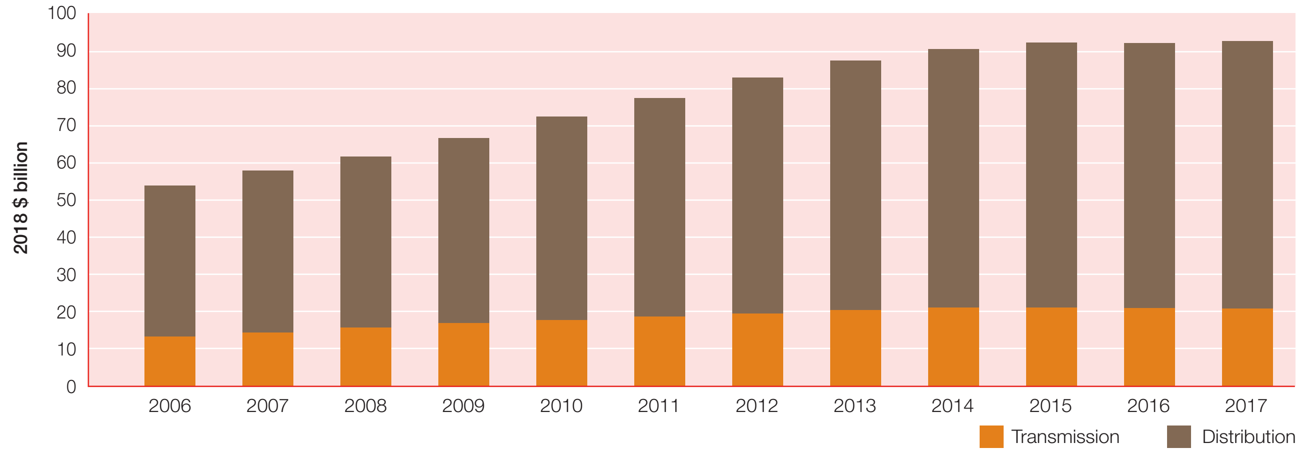
31 Measured in real (2017) dollars.

32 Some of those processes were ongoing. Details of how RIT–T and RIT–D tests are applied to particular projects can be found in AER, *Review of the application guidelines for the regulatory investment tests*, Issues Paper, February 2018. The RIT–T was introduced in 2010 and the RIT–D in 2014.

33 AER, *AER releases determination on Sydney CBD RIT–D dispute*, media release, 25 October 2018.

Figure 3.14

Value of network assets



Note: Closing RABs for electricity networks in the NEM, June 2018 dollars. Assumptions set out in notes to figures 3.7 and 3.8.

Source: Economic benchmarking RIN responses and AER modelling.

The AEMC widened the regulatory tests in July 2017,[34] and the AER amended its guidelines to implement the change.[35] The amended test imposes new reporting requirements on network businesses to justify asset retirement decisions and allow interested parties to propose alternatives to asset replacement.

Separately, the AER in 2018 completed a review of the RIT–T to ensure it adequately considers system security, emissions reduction goals, and events with a low probability of occurring but high impact. The review also explored how to better align the RIT–T with the RIT–D and how the tests can work jointly with AEMO's integrated system plan (ISP) for optimising transmission investment.[36] In particular, the RIT–T needs to complement the ISP's approach to identifying which transmission upgrades and interconnectors are in the long-term interest of consumers. The AER released draft application guidelines in July 2018, with a view to finalising the review in late 2018.[37]

The COAG Energy Council also asked the AEMC to explore whether the AER should have greater oversight over the RIT–T process, and whether civil penalty provisions should be introduced. The AEMC in December 2017 recommended that breaches of regulatory test processes be subject to civil penalty provisions.[38]

3.11.4 Annual planning reports

The regulatory test framework does not operate in isolation. Other mechanisms complement the framework, and the AER has recently applied measures to improve their effectiveness.

Network businesses must publish *annual planning reports* to identify new investment that may be needed to efficiently deliver network services. The reports provide public information on emerging network constraints, including potential 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.

In light of the AEMC's July 2017 rule change on the regulatory investment tests, network businesses will be required to expand their planning reports to include network asset retirement and de-rating information. In 2017 the AER also published a template to improve the consistency and usability of distribution planning reports. In 2018 it began consulting on similar guidelines for transmission networks.[39]

34 AEMC, *Replacement expenditure planning arrangements rule*, factsheet, 18 July 2017.

35 AER, *RIT–T and RIT–D application guidelines (minor amendments) 2017*.

36 AEMO, *Integrated system plan for the National Electricity Market*, July 2018.

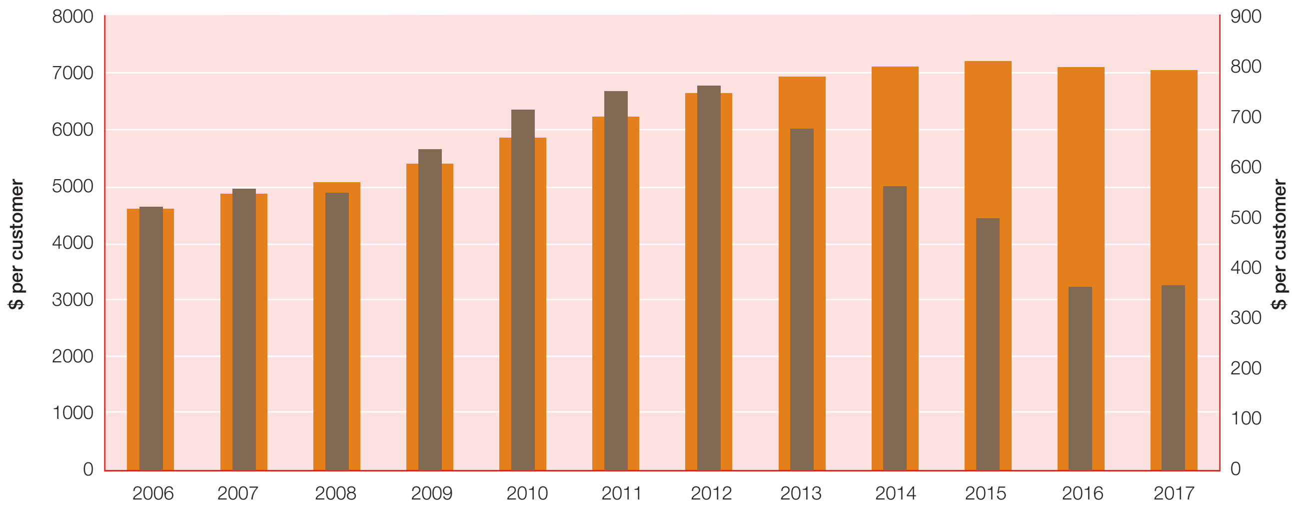
37 AER, *Review of the application guidelines for the regulatory investment tests for transmission and distribution*.

38 AEMC, *Rule determination: National Electricity Amendment (Contestability of energy services) Rule 2017*, December 2017, p. 130.

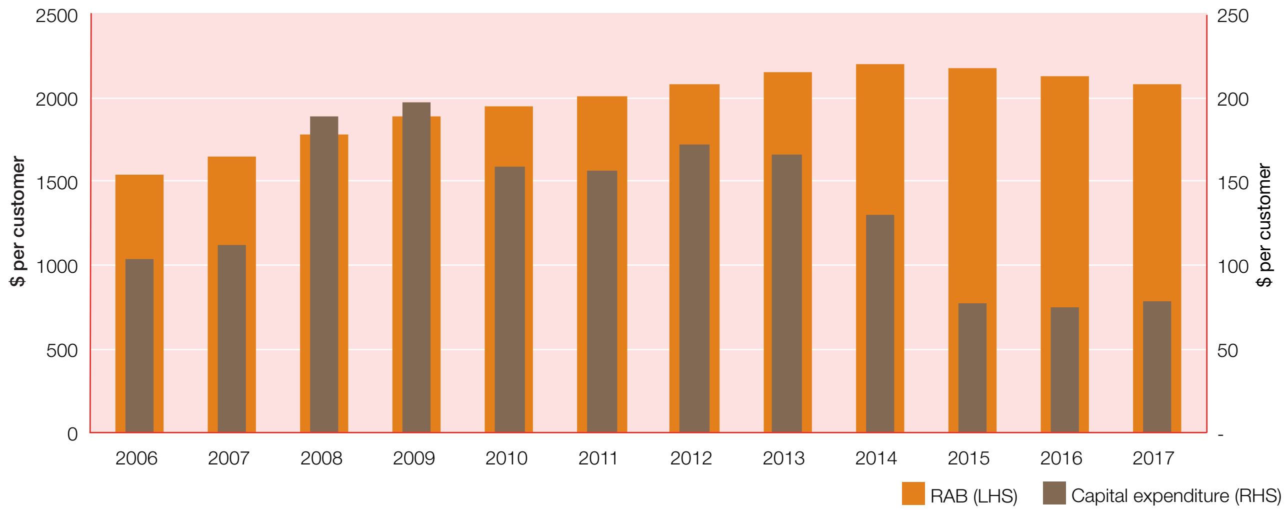
39 AER, *Transmission Annual Planning Report Guideline, Consultation paper*, April 2018.

Figure 3.15
Network investment and asset base per customer

Distribution



Transmission

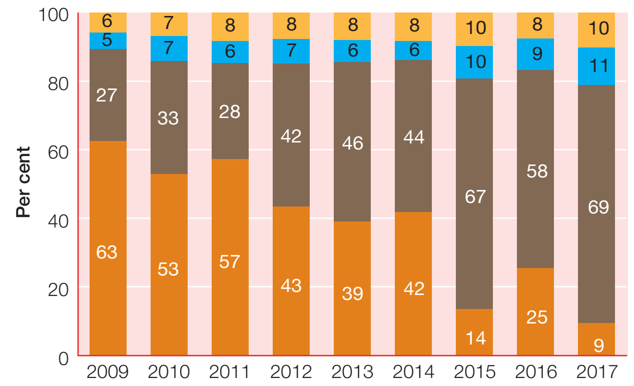


Note: Closing RABs, June 2018 dollars. Investment is actual outcomes on an end of year basis, 2018 dollars. Assumptions set out in notes to figures 3.7 and 3.8.

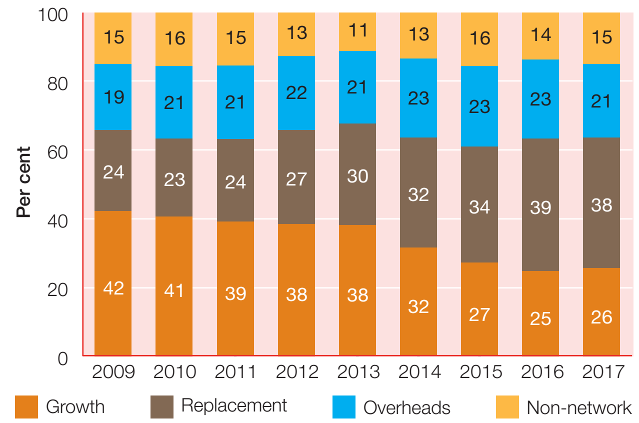
Source: Economic benchmarking RIN responses and AER modelling.

Figure 3.16
Network expenditure by driver

Transmission



Distribution



Source: AER economic benchmarking RINs and AER modelling.

3.11.5 Demand management

The AER in December 2017 launched new initiatives encouraging network businesses to find lower cost alternatives to new investment to help cope with changing demands on the network and manage system constraints. An enhanced *demand management incentive scheme* 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 expanded its *demand management innovation allowance*. This is a research and development fund to help distribution businesses develop new ways of using demand management to keep network costs down in the longer term. The new allowance provides funding to expand research and development by around 30 per cent from previous levels. To provide accountability, project eligibility criteria were tightened and reporting requirements clarified to emphasise sharing of project learnings across the industry and with consumers.

The incentive scheme and updated innovation allowance apply in regulatory periods commencing from 1 July 2019. To enable greater uptake, the AEMC in 2018 approved an AER rule change request to allow early application of the new scheme. By October 2018 three distributors—AusNet Services, Energex and Ergon Energy—had applied to bring forward new demand management projects.

Funded projects under earlier versions of the schemes included trials of innovative tariffs and customer payments designed to incentivise customers to reduce (or shift) their use at peak demand times.

Energex, for example, introduced demand based electricity tariffs in 2016 to test whether it incentivised customers to adopt technologies such as battery storage, and whether educational and promotional materials would encourage the adoption of more cost reflective tariffs. United Energy's 'summer saver' program trialled bonus payments ('critical peak rebates') to customers for reducing their demand at peak times.

Other funded projects focused on technology solutions, including load control devices and storage (batteries), and improving network system controls and information. Battery storage trials, either at grid scale or at the residential level, were undertaken in all regions and accounted for over one third of all innovation allowance expenditure (figure 3.17).

In addition to managing network constraints, demand response provided by network businesses can help manage wholesale electricity supply during extreme peaks. The Australian Renewable Energy Agency (ARENA) and AEMO in 2017 announced a three year trial of demand response technologies and services to deliver 200 megawatts of capacity in the NEM by 2020. Among the ten selected projects was a United Energy proposal to install voltage control devices at substations to better manage voltage issues and electricity use during peak demand surges.

Network businesses varied in their appetite to use funding available under the previous demand management innovation allowance. Of the 13 distributors, only AusNet Services, SA Power Networks and TasNetworks had spent (or were on track to spend) their full funding allocation by mid-2017.[40]

3.12 Rates of return for network businesses

The shareholders and lenders who finance the assets operated by a network business must be paid a commercial return on their investment. The dollar returns paid to investors each year is calculated by multiplying the asset base by the *rate of return*.[41] Given electricity networks are capital intensive, this return typically accounts for around 50 per cent of a network' revenue.

The rate of return estimates the cost of funds a network business requires to make investments. It combines the returns needed to attract two sources of investment funding—*equity* (funding provided by the network owner or shareholders) and debt (funding borrowed from banks and other lenders). The *return on equity* is the return required by shareholders of the business for them to continue to invest. The *return on debt* is the interest rate the network business needs to pay when it borrows money to invest. For this reason, the allowed rate of return is sometimes called the weighted average cost of capital.

If the rate is set too low, the networks may not be able to attract sufficient funds to be make required investments to maintain reliability and safety of supply. But if the rate is set too high, the networks are incentivised to over-invest, and consumers pay for a 'gold plated' network they do not need.

Estimation of the rate of return is complex, and a significant driver of network revenue. A small rise in the rate of return will significantly impact revenues (and energy bills for customers). A 1 percentage point increase in the allowed rate of return for TransGrid's NSW transmission network would increase its forecast revenues from 2018–23 by around 10 per cent, for example. For this reason, the rate of return is often the most contentious part of a revenue decision.

Conditions in financial markets are a key determinant of the allowed rate of return. AER decisions from 2009–12 occurred 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 was as high as 10 per cent in decisions in 2008–10 (figure 3.18). Additionally, the Tribunal increased some rates of return following appeals by the network businesses.

The financial environment improved from 2012, and borrowing and equity costs eased accordingly. AER decisions since 2015 also adopted a new approach to determining rates of return, with the cost of capital updated annually to reflect changes in debt costs. Stable financial market conditions resulted in an average allowed rate of return of around 6 per cent in decisions from 2016–18, compared with over 10 per cent in decisions from 2009–11. These lower rates of return have been a key driver of lower network revenues and charges over the past few years (figures 3.7 and 3.8).

3.12.1 Profitability reporting

In response to calls for greater transparency around the actual returns achieved by the businesses, the AER in September 2018 began publishing information about network businesses' profitability. Some observers are concerned networks may be earning excessive profits, given the market risks they face. In the first phase of this initiative return on assets data for each network business was published. More comprehensive reporting will follow in 2019.

Figure 3.19 compares approved rates of return for network businesses in 2016–17 with the returns actually earned by each business in that year (excluding bonuses earned under regulatory incentive schemes). While the data indicates several businesses earned above their regulated rates of return, it represents the first stage of developing profitability reporting and should be interpreted with caution.[42]

3.12.2 Review of the rate of return

In the past, the AER set a separate rate of return for each network as part of its revenue determination. The AER published non-binding guidelines on its approach in 2013, following extensive consultation with businesses. Despite this, the process of applying the guideline has been adversarial, with businesses frequently making a case to deviate from it in their revenue proposals. Over the past five years, many network businesses argued for a different approach or different parameters. The AER's decisions—which were consistent with the guidelines—were often challenged. Legal battles were long, costly and added to uncertainty for the businesses, consumers and investors. Some decisions originally made in 2015 were still being remade in 2018 (section 3.5.2).

To provide certainty and predictability for stakeholders, the COAG Energy Council in 2017 agreed to make the AER's rate of return guideline binding on both the AER and energy networks. From December 2018 a new binding guideline will apply to revenue decisions made over the next four years.

To ensure an open and transparent review, the AER set up comprehensive consultation and engagement processes, including:

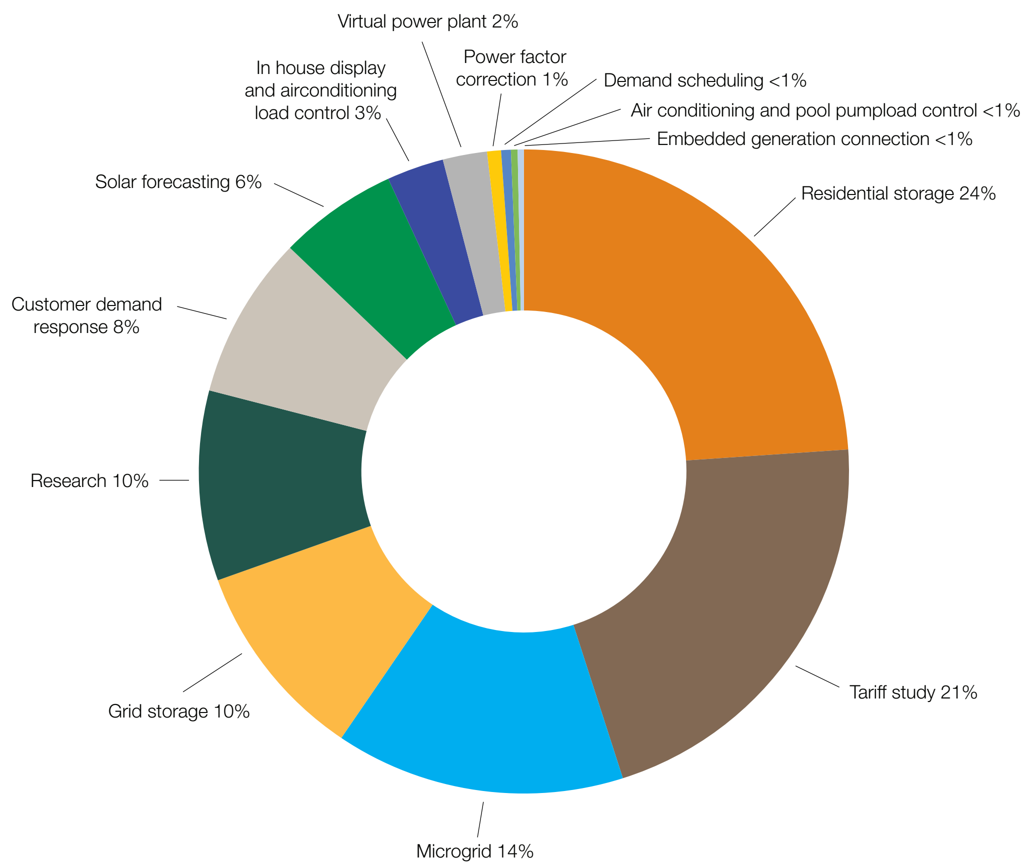
- a consumer reference group comprising academics, energy consumer associations, community and advocacy groups, to provide ongoing feedback throughout the review
- a dedicated consumer challenge sub-panel
- an investor reference group, to provide direct feedback from investors
- expert evidence 'hot-tubbing' sessions, to allow the AER Board to explore areas of agreement/disagreement between finance experts
- an independent panel to review the AER's draft guideline and report back before its final decision.

40 AER, *Approval of Demand Management Innovation Allowance (DMIA) expenditures by distributors in 2016–17 and 2017*, July 2018.

41 If the rate of return is 5 per cent, and the RAB is $50 billion, for example, 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.

42 Time series data is published on the AER website at www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/profitability-measures-for-electricity-and-gas-network-businesses.

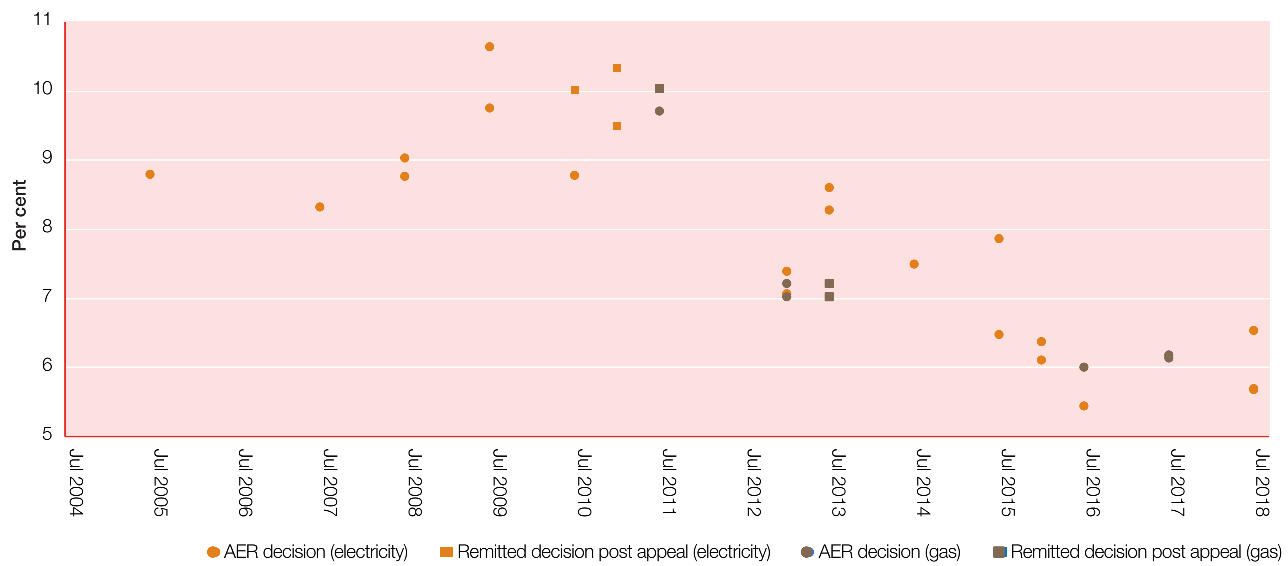
Figure 3.17
Demand management innovations funded in 2016–17



Note: per cent of total funding applied under the scheme. 2016–17 data (2017 for Victoria).

Source: AER, *Approval of Demand Management Innovation Allowance expenditures by distributors*, July 2018.

Figure 3.18
Rates of return for energy networks



Note: Nominal vanilla WACC.

Source: AER decisions on electricity network revenue proposals and gas pipeline access arrangements; AER decisions following remittals by the Tribunal/Full Federal Court.

The AER's draft decision published in July 2018 would, if implemented, reduce a typical residential electricity bill by around $30–40 per year.[43]

3.13 Electricity network operating costs

Electricity network businesses face various operating and maintenance costs in supplying electricity to consumers. These costs absorb around 30 per cent of a network's annual revenues.

Businesses present their cost forecasts to the AER as part of their revenue proposals. The AER then assesses whether those forecasts reasonably reflect the efficient costs of supplying power to customers. In making this assessment it forecasts various cost drivers such as electricity demand, productivity improvements, changes in labour and materials costs, and changes in the regulatory environment. If the AER does not consider a business's cost forecasts to be reasonable, it may replace them with its own cost forecasts.

Additionally, the AER runs an *efficiency benefit sharing scheme* (EBSS), offering incentives for network businesses to keep their operating and maintenance spending to efficient levels. The scheme allows business to retain efficiency gains for up to five years—but they must also bear efficiency losses. In the longer term, network businesses must share efficiency gains with customers, passing on 70 per cent of the gains as lower network charges.

3.13.1 Operating cost expenditure

Electricity networks in the NEM spent $3.7 billion on operating and maintenance costs in 2017, a 2.8 per cent decrease on the previous year (figure 3.20):

- Distribution businesses spent $3 billion in operating costs in 2017—16 per cent lower than in 2012, when those costs peaked in the sector.
- Transmission businesses spent $720 million in operating costs in 2017—less than 1 per cent lower than 2016, when those costs peaked in the sector.[44]

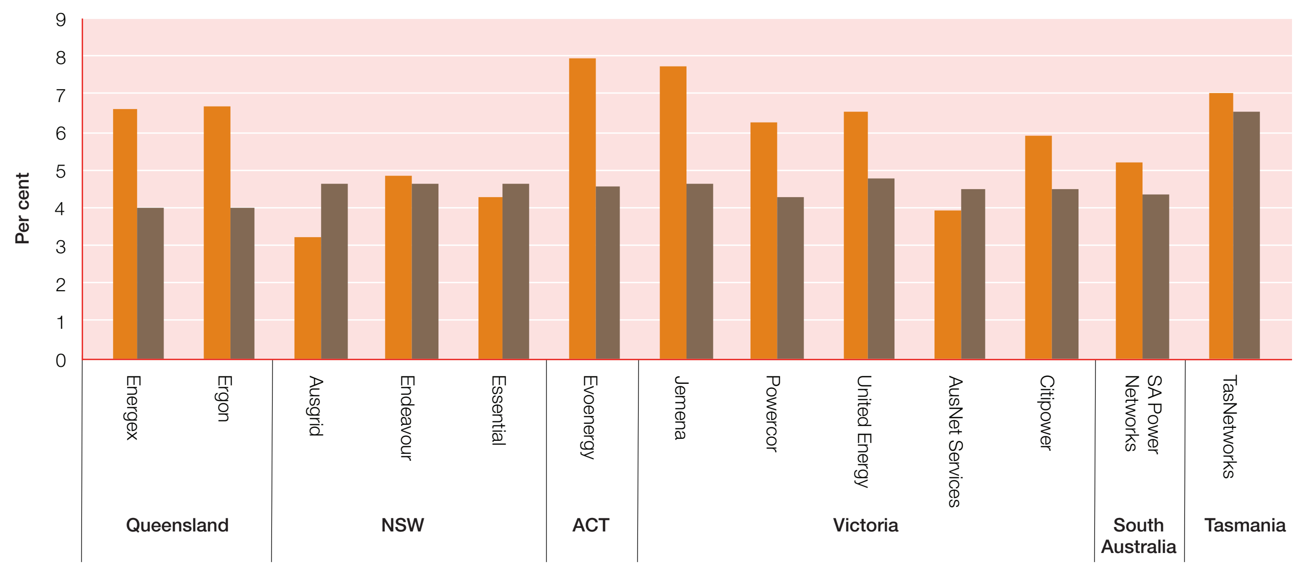
There was a sustained escalation in operating costs from 2006–2012, followed by a four year plateau, with a shift to lower costs in 2016 and 2017. Actual costs tended to

43 AER, *AER releases draft decision on new Rate of Return Guideline*, media release, 10 July 2018.

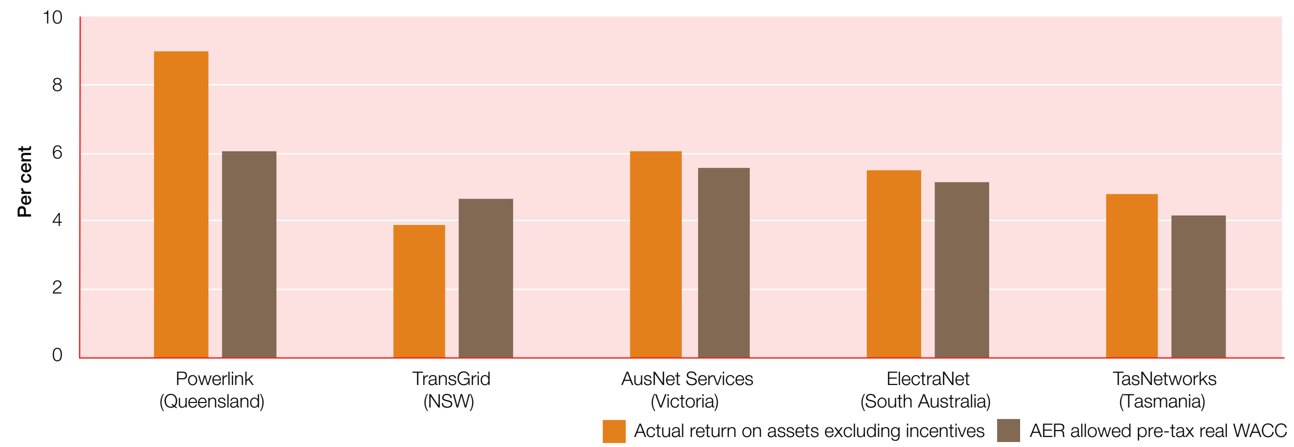
44 The assumptions underpinning data in this chapter are explained in the notes to figures 3.7 and 3.8. Unless otherwise stated, data refers to actual outcomes adjusted to 2017 dollars.

Figure 3.19
Rates of return for network businesses, 2016–17

Distribution



Transmission



WACC, weighted average cost of capital.

Note: Rates of return for 2016–17. Outcomes for NSW and ACT electricity distributors were affected by transitional arrangements pending the outcome of legal appeals.

Source: AER, *Profitability measures for electricity and gas network businesses*, September 2018.

outpace forecasts in most years, though they were slightly below forecast in 2017.

While operating expenditure has eased since 2012, the reduction is less marked than for capital expenditure. Operating and maintenance costs are largely independent of electricity use. This means operating costs do not decline significantly with falling electricity demand., and long term trends shift gradually. This is especially the case for transmission, where operating costs grew fairly steadily from 2006–16, before easing slightly in 2017. Shifts in costs for distribution networks tend to be more pronounced. The 20 per cent reduction in operating costs for that sector since 2014 reflects significant efficiencies being achieved in some networks.

3.13.2 Recent operating cost outcomes

AER decisions in place at 1 July 2018 forecast network operating costs being 4.9 per cent lower on average than in the previous round of AER assessments (figure 3.21). However, outcomes varied. In distribution, operating costs were forecast to rise for the Victorian and South Australian networks, but to fall significantly in Queensland, NSW, ACT and Tasmania.

A number of networks have implemented efficiencies in managing their operating costs since 2015, when the AER widened its use of benchmarking to identify operating inefficiencies in some networks. The AER's EBSS also incentivises network businesses to spend efficiently.

In current decisions, a combination of AER incentives and network driven efficiencies drove significant cost reductions, especially among government owned (or recently privatised) distribution networks in NSW, Queensland and Tasmania, and the part government owned ACT network. The largest cuts were for distribution networks in Queensland (where operating costs are forecast to fall by 23–34 per cent), NSW (falls of 15–28 per cent) and Tasmania (a fall of 21 per cent).

Operating costs were forecast to rise for the privately owned Victorian and South Australian distribution networks. The AER found some of these businesses had been improving efficiency for some time, so their base levels of expenditure were already leaner than for networks elsewhere. New regulatory obligations—including new regulatory information reporting processes, changes to the connections charging framework, and Power of Choice requirements—were also forecast to raise operating costs in some areas.

Outcomes tended to be steadier in transmission than distribution. Current AER decisions allow for higher transmission operating costs in Victoria, NSW and South Australia, but lower costs in Queensland and Tasmania.

The AER in 2018 made final revenue decisions on three transmission networks—ElectraNet in South Australia, TransGrid in NSW and the Murraylink interconnector. Its decisions for ElectraNet and TransGrid allowed 4–5 per cent increases in operating expenditure over the previous regulatory period. This partly reflects new obligations on the businesses arising from recent market reviews, rule changes, and revised licence conditions. ElectraNet identified additional obligations relating to frequency control and fault management, connection and planning arrangements, and generator licensing arrangements. TransGrid identified revised licence conditions and additional network support costs associated with its Powering Sydney's Future project.

3.14 Electricity network productivity

The AER's benchmarking work tracks the relative efficiency of electricity networks over time. The AER applies a *multilateral total factor productivity* approach to benchmark how effectively a network uses its inputs (assets and operating expenditure) to produce outputs. Indicators include maximum electricity demand, electricity delivered, reliability of supply, customer numbers (only for distribution networks), line length and the voltage of transmission connection points.

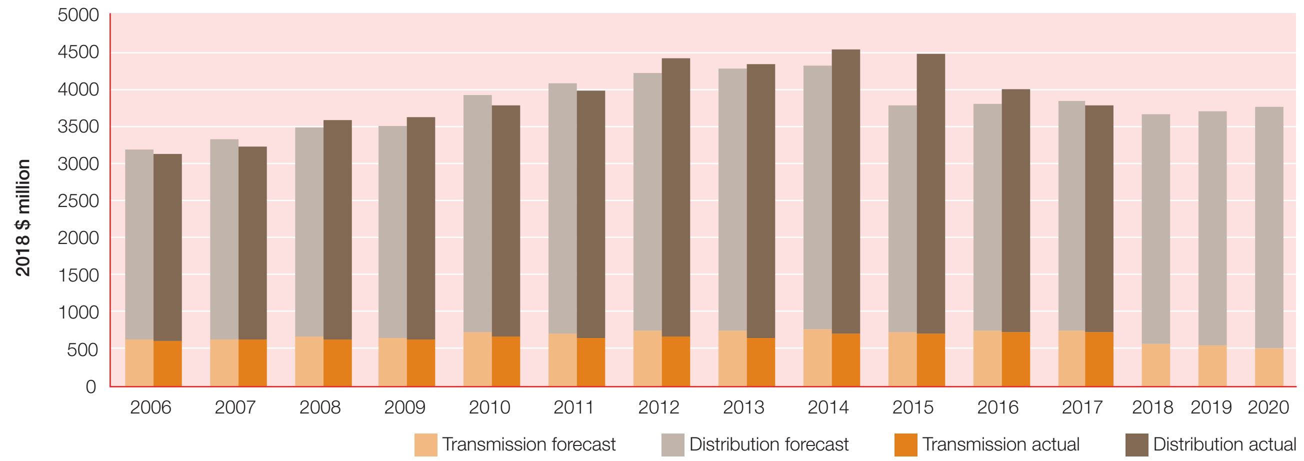
The AER considers benchmarking a useful tool for comparing the performance of different networks. But there may be operating environment factors not fully captured in its model that drive apparent differences in estimated productivity and operating efficiency across networks in the NEM. The benchmarking models do not directly account for differences in legislative or regulatory obligations, climate and geography, for example. The AER in October 2018 published research into the impact of operating environment factors on distribution networks, which will be used as part of its continuous refinement of benchmarking techniques.[45]

Productivity will rise if the resources used to maintain, replace and augment energy networks rise faster than the demand drivers for network services.[46] Some productivity

45 AER, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, Simon Orme, Dr. James Swansson, Geoff Glazier, Ben Kearney, Dr Howard Zhang, October 2018.

46 The AER uses a multilateral total factor productivity approach to measures networks' relative productivity performance over time. The approach assesses the volume of inputs needed to produce specified outputs.

Figure 3.20
Annual network operating costs—forecast and actual



Note: Actual outcomes for relevant year on an end of year basis, 2018 dollars. Assumptions set out in notes to figures 3.7 and 3.8.
Source: Economic benchmarking RIN responses; AER revenue determinations; AER modelling.

drivers are beyond the control of network businesses—for example reliability standards set by government bodies.

Productivity in most networks declined from 2006–15, especially in the distribution sector. Over this period, the privately owned networks in Victoria and South Australia tended to operate more efficiently than government owned (or recently privatised) networks in Queensland, NSW, the ACT and Tasmania.[47]

But this trend has reversed since 2015. Productivity in distribution networks rose by 5 per cent over the two years to 31 December 2017, the most positive outcome in over a decade. Transmission networks also improved their productivity in 2017, averaging a 6 per cent rise over in the year.[48]

3.14.1 Transmission network productivity

The electricity transmission sector achieved an overall productivity gain of 5.8 per cent over the two years to 31 December 2017. The gain in each year was higher than for any other year since 2006. Powerlink (Queensland) was the only network not to make productivity gains in 2017.

47 Queensland Government, *Independent Review Panel on Network Costs, Electricity Network Costs Review, Final Report*, June 2014, p. 102. Quoted in ACCC, *Retail Electricity Pricing Inquiry—Final Report*, June 2018 p. 108

48 AER, *Annual benchmarking report: electricity transmission network service providers*, November 2018; AER, *Annual benchmarking report: electricity distribution network service providers*, November 2018.

Improved network reliability contributed around 70 per cent of productivity improvements in NSW, Victoria and South Australia. Other factors included reductions in overhead line length in Queensland and NSW, and growth in energy throughput in all networks outside Victoria. Gains in Tasmania were largely driven by lower operating costs.[49]

The Victorian and Tasmanian networks ranked highest by productivity score in 2017. The South Australian and NSW networks ranked mid-range, while the Queensland network ranked lowest.

Regulatory incentives may be contributing to improved outcomes. In particular, the AER allows network businesses to retain efficiency gains for up to five years. Additionally, it may remove inefficient investment from the regulatory asset base.

Recent outcomes reversed a trend of poor industry performance (figure 3.22). Transmission network productivity in NSW, Queensland and South Australia declined by 20 per cent over the 11 years to 2017. Over that period, productivity improved only in the Victorian and Tasmanian networks (by around 10 per cent).[50]

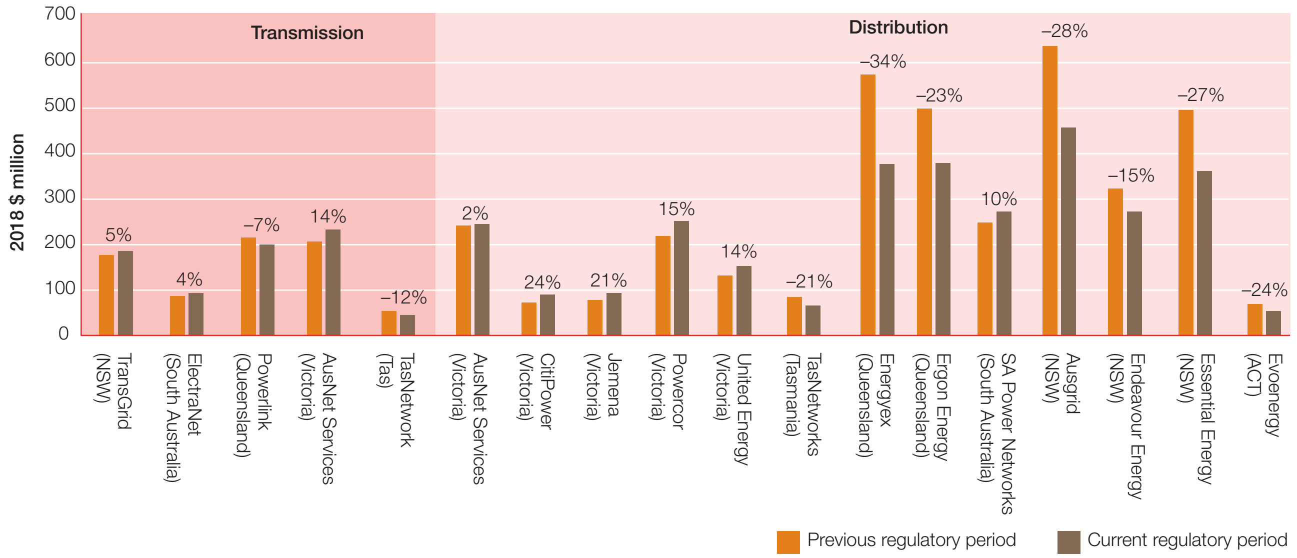
Rising capital investment (inputs) at a time when electricity demand (output) had plateaued or was declining drove

49 AER, *Annual Benchmarking Report, Electricity distribution network service providers*, December 2018.

50 In this section, industry wide data are based on Total Factor Productivity measures. Outcomes for particular networks and comparisons across networks are based on Multilateral Total Factor Productivity or Multilateral Partial Factor Productivity. See AER, *Annual Benchmarking Report, Electricity transmission network service providers*, November 2017.

Figure 3.21

Network operating expenditures—change from previous period



Note: Smoothed annual averages, 2018 dollars. Actual outcomes for previous regulatory period, and forecasts for current period. Percentages represent the forecast change from the previous regulatory period. Revisions may result in some outcomes varying from those previously reported.

Current regulatory periods at 1 July 2018 (see table 3.1 for transmission and table 3.2 for distribution). Determinations in each sector appear in chronological order of the decision dates (listed in tables 3.1 and 3.2).

Source: AER economic benchmarking RINs; AER regulatory determinations; AER modelling.

weaker productivity outcomes in many networks. Only Victoria recorded relatively stable productivity relating to capital inputs over the decade. For most networks, operating cost inputs also drove weaker productivity (only Tasmania achieved higher productivity in this area). Deteriorating network reliability also reduced productivity.

3.14.2 Distribution network productivity

The electricity distribution sector achieved an overall productivity gain of 5 per cent over the two years to 31 December 2017, comprising a 2.7 per cent rise in 2016 (the most positive outcome in over a decade) and a further 2.2 per cent in 2017.

Driving these gains were reductions in operating expenditure over both years, and in 2017, growth in customer numbers and a reduction in the number of minutes off supply. Network businesses lowered their operating expenditure through efficiency drives, including through workforce restructuring and redundancies. Savings in operating expenditure were greater than suggested by the benchmarking results, due to one-off costs associated with restructuring programs. Removing the cost of redundancy programs from the 2016 data would see the reported 2.7 per cent increase rise to 5.1 per cent, for example.

Regulatory incentives may be contributing to improved outcomes (section 3.13).

The productivity of 10 of the NEM's 13 distribution networks improved over the two years to December 2017. Powercor (Victoria), Energex and Ergon Energy (Queensland), Essential Energy and Ausgrid (NSW), and Evoenergy (ACT) each improved their productivity by over 5 per cent.

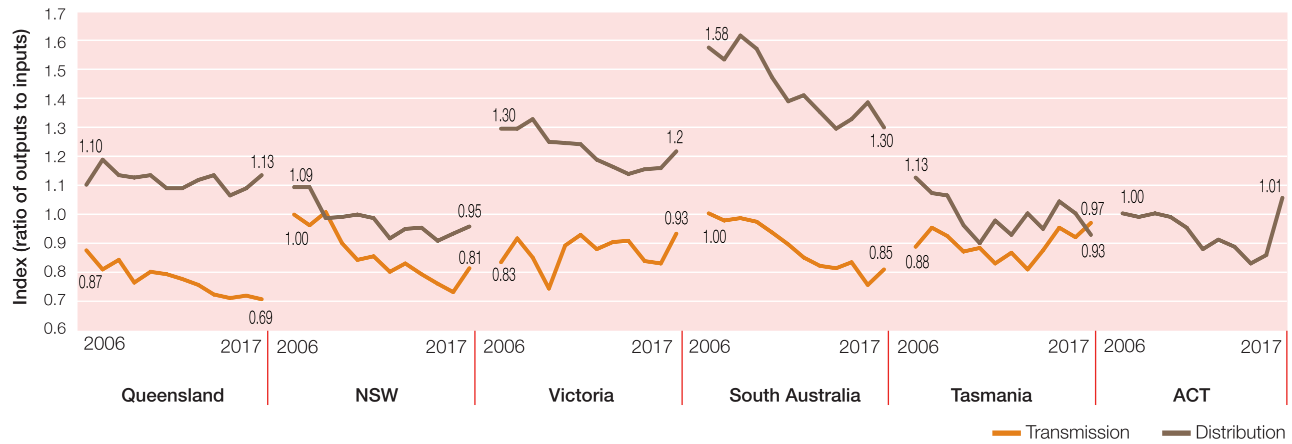
The only networks to record declining productivity were Jemena (Victoria), SA Power Networks (South Australia) and TasNetworks (Tasmania). The outcome for SA Power Networks mainly reflected increased operating expenditure to manage severe weather events. Similarly, TasNetworks faced higher operating costs due to bushfire and asset related risks.

CitiPower (Victoria) was the best performing network in 2017, followed by SA Power Networks (South Australia), United Energy and Powercor (Victoria). These four networks were consistently the best performers over the past 12 years. The AER's 2015 regulatory decision to scale back SA Power Network's operating expenditure contributed to improved outcomes for that network.

Government owned networks have improved their operating expenditure efficiency in recent years through efficiency

Figure 3.22

Electricity network productivity



Note: Index of multilateral total factor productivity relative to the 2006 performance of ElectraNet (South Australia). Distribution outcomes are averaged for jurisdictions with multiple networks (Victoria, NSW and Queensland). Data is not comparable to that published in *State of the energy market 2017* due to methodology changes (see AER, *Annual benchmarking report: electricity transmission network service providers*, November 2017, page 6). The ACT does not have a transmission network.

Source: AER, Annual benchmarking reports for electricity transmission and distribution networks.

reforms and restructuring, including by significantly reducing their workforce. While Ausgrid and Essential Energy (NSW) recorded among the poorest productivity outcomes in 2017, both are implementing reform programs to better manage their operating expenditure, as reflected in the AER's remade 2014–19 revenue decisions, and draft 2019–24 revenue decisions for those networks.

Recent improved outcomes come after a period of poor industry performance (figure 3.22). Distribution network productivity declined on average by 1.3 per cent annually over the nine years to 2015. Rising capital and operating expenditure (inputs) at a time of weakening electricity demand (output) drove these outcomes. Expenditure rose in part to meet stricter reliability standards in NSW and Queensland, and regulatory changes following bushfires in Victoria. The privately operated networks in South Australia and Victoria consistently recorded higher productivity scores over this period than government owned or recently privatised networks.

The decline in productivity plateaued from 2012 as the NSW and Queensland governments relaxed reliability standards, and new energy rules allowed the AER to scale back investment and cost proposals by some networks. In Tasmania, a merger between the transmission and distribution networks created opportunities to adopt new operational efficiencies. Similarly, the Queensland Government in 2016 merged its state owned electricity distributors to form a single parent company.

3.14.3 Investment disconnect

A key contributor to the poor productivity performance among electricity networks over the past decade was sustained investment growth at a time when electricity use was falling (figure 3.23). Investment rose almost continuously from 2006–12 in both transmission and distribution. But electricity transmitted peaked in 2008 in transmission and 2010 in distribution, before sharply declining in both sectors. The decline began earlier in transmission due to the losses of a number of industrial loads.

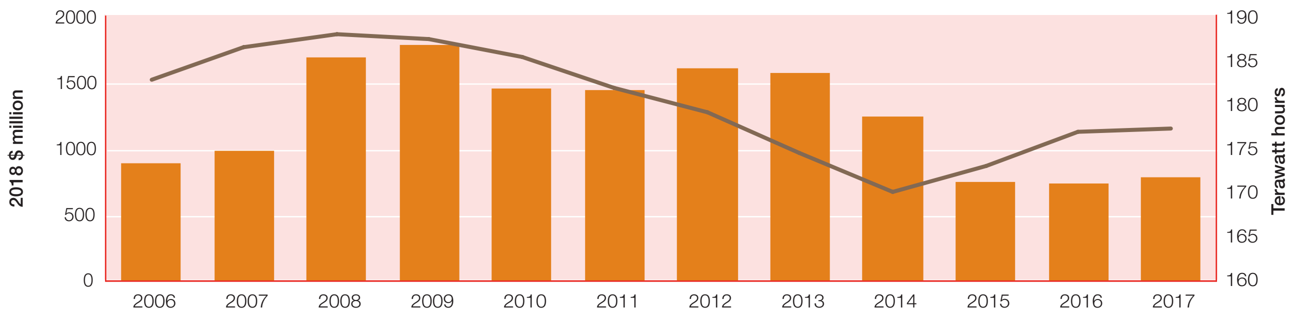
There were two key drivers of this mismatch between electricity use and new investment—a growing divide between maximum network demand and total electricity generated, and inaccurate forecasts of growth in maximum demand.

Network productivity is dependent on overall use of assets to meet a range of outcomes, including reliability. But capital expenditure was, to a large extent, driven by the need to meet the maximum level of demand on the network. As network demand becomes 'peakier', assets installed to meet maximum demand may sit idle (or be underused) for long periods. While total energy delivered fell over the period 2006–17 by 2.5 per cent, maximum demand increased on all networks by an average of 1 per cent each year.

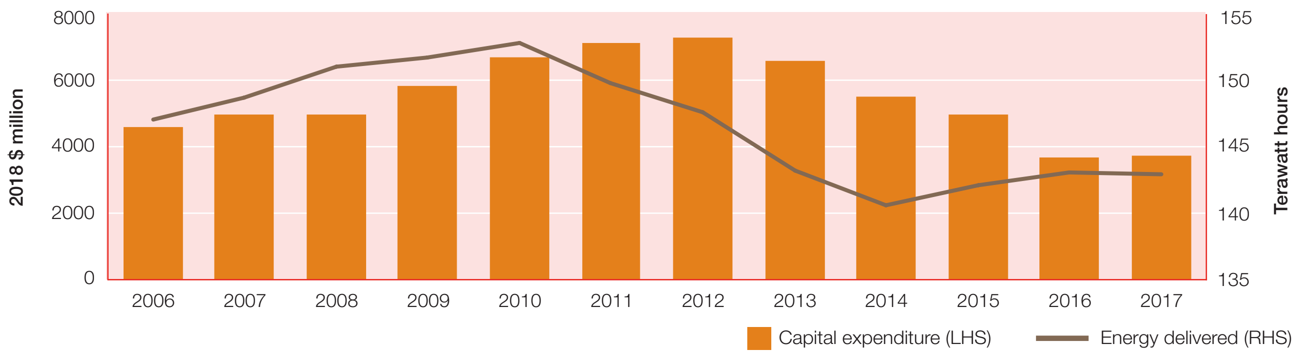
Demand response allows networks to meet short term peaks in demand without the need for investment in long lived assets (section 3.11.5).

Figure 3.23
Investment and energy delivered

Transmission



Distribution



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

Source: AER, Annual Benchmarking Reports 2018; RINs submitted by network businesses.

Forecasts by planning authorities and market participants consistently failed to capture a step change decline in electricity use and the flatlining of maximum demand that began around 2006. This is when customers began adopting energy efficiency measures and self-generating electricity with rooftop solar PV systems. A contraction in electricity use in the manufacturing sector also proved to be long term rather than cyclical.[51]

These inaccurate forecasts raised concerns the predicted growth in electricity demand could outstrip supply. In response, the energy rules were redrafted in 2006 to encourage new investment to meet demand growth that never eventuated. But that investment inflated the regulatory asset bases of electricity networks, which customers continue to pay for.

This over-investment contributed to poor productivity outcomes. The AER reported a declining trend in capital productivity for all transmission networks from 2006–17, except AusNet Services (Victoria).[52] In distribution, the AER found over-investment also drove weaker productivity, although to a lesser extent than growth in operating expenditure. Only Ergon Energy (Queensland) recorded an improvement in capital productivity over the period. But

51 AEMC, *Electricity Network Economic Regulatory Framework Review*, 18 July 2017, pp. 37–38.

52 AER, *Annual Benchmarking Report, Electricity transmission network service providers*, December 2018.

slower growth in capital inputs has contributed to improved productivity outcomes since 2012.[53]

3.14.4 Adapting to an evolving market

The AEMC found in 2018 that as the market evolves, the regulatory framework may discourage network businesses from making efficient choices between their capital and operating expenditure programs. This particularly impacts non-network (demand response) projects that can be offered by third parties. A traditional network solution to meet increasing consumer demand in an area might be to augment a zone substation, for example. But it may be more efficient to purchase services from a battery provider, or an aggregator of many small scale batteries, to reduce peak demand.

The current framework encourages businesses to favour (expensive) long lived capital expenditure solutions over cheaper operating expenditure alternatives, especially if the business' regulated rate of return is higher than current borrowing costs. AER incentive schemes seek to limit this bias. Another solution may be a more holistic approach to regulatory assessments of capital and operating expenditure programs. The AEMC will further explore these issues in 2019.

3.14.5 Network usage

Usage (or utilisation) rates are a partial productivity measure, indicating the extent to which a network's assets are being used to meet maximum demand. As noted above, network use can be improved by using demand response rather than additional network investment.

Capacity use tends to be higher in the privately owned distribution networks in Victoria and South Australia (58 per cent) than in networks that are fully or partially government owned (38 per cent). But since 2014, the partially privatised networks in NSW have improved outcomes (figure 3.24).

Usage rates declined almost continuously from 2006–15, from around 56 per cent to 45 per cent. A key factor underpinning the decline has been over-investment in new assets at a time of weakening electricity demand. Demand forecasts since 2004 consistently over-estimated the growth in maximum electricity demand. Networks investment in new assets was based on these inflated forecasts.

Usage rates improved after 2015 in NSW, South Australia and Queensland, reflecting lower levels of new investment. They also improved in Victoria in 2016, but eased in 2017. Usage rates for the ACT are more variable.

Underuse of assets raises concerns about asset stranding—where assets form part of the RAB but are no longer useful—if network businesses do not respond to changing conditions. The risk of stranded assets may become more acute as the uptake of decentralised generation transforms the industry. The electricity rules do not allow for regulatory asset bases to be adjusted to reflect asset stranding. This means network businesses have little incentive to avoid over-investment. Electricity consumers—who have to pay for stranded assets—may also have an incentive to seek ways to bypass the grid.[54]

3.15 Network reliability

Reliability refers to the continuity of electricity supply to customers. Many factors can interrupt the flow of electricity on a network. 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). A serious 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 can also overload parts of a distribution network during extreme weather. Transmission network issues rarely cause consumers to lose power, but their effect is widespread. South Australia's catastrophic network failures in September 2016 caused the entire state to be blacked out, for example.

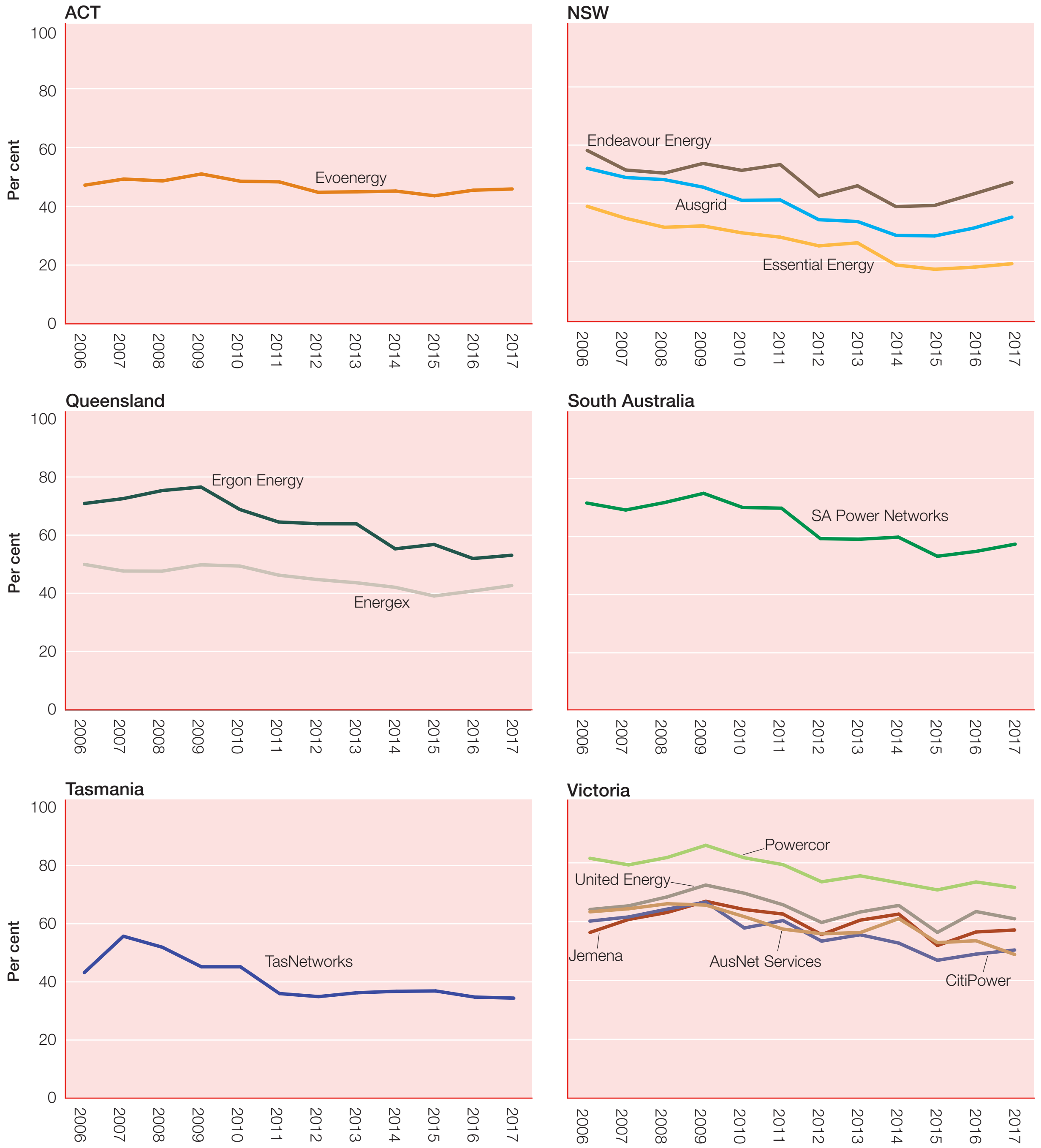
Electricity outages impose costs on consumers. Costs include financial losses resulting from lost productivity and business revenues, and intangible costs such as reduced convenience, comfort, safety and amenity.

Household and business consumers desire a reliable electricity supply that minimises these costs. But a reliable electricity supply requires investment in transmission and distribution in network assets, which is paid for by electricity consumers. These costs form a significant portion of consumer bills. There is, therefore, a trade-off between electricity reliability and affordability. It is important

53 AER, *Annual Benchmarking Report, Electricity distribution network service providers*, December 2018.

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

Figure 3.24
Distribution network capacity usage



Note: Non-coincident summated raw system annual peak demand *divided by* total zone substation transformer capacity.
Source: AER, Annual Benchmarking Reports 2018; RINs submitted by network businesses.

that reliability standards strike the right balance by considering the value customers place on different levels of network reliability.

3.15.1 Reliability standards

State and territory governments set reliability standards for electricity networks that seek to efficiently balance the costs and benefits of a reliable power supply. Approaches to setting standards vary across jurisdictions. Strict reliability standards operated for several years in NSW and Queensland, for example, requiring substantial network investment that contributed to escalating power bills from around 2006–14.

More recently, governments have moved to a more consistent national approach to reliability standards, including factoring in the value consumers place on having a reliable power supply.

3.15.2 Valuing reliability

The COAG Energy Council agreed in 2014 that reliability standards should reflect the value customers place on reliability—that is, customers' willingness to pay for a reliable electricity supply, measured in dollars per kilowatt hour. Understanding how customers value reliability is an important consideration when balancing delivery of secure and reliable electricity supplies against reasonable costs for electricity customers.

A customer's valuation of reliability depends on many factors. These factors include the customer's access to alternative energy sources, their past experience of supply interruptions, and the duration, frequency, timing and location of an interruption. In particular, many outages occur on hot summer days when the networks are under strain and at capacity.

Understanding the value customers place on reliable supply in different parts of the network can help network businesses and planners deliver the right level of investment to meet customer needs on peak summer days. Expensive overbuilds can be avoided where they are not needed, while ensuring a reliable supply where and when customers want it the most.

AEMO surveyed customer reliability values in 2014, which were later used to set transmission reliability standards in Victoria, South Australia and, from July 2018, NSW.

The AER also uses the values as an input to its regulatory assessments for network businesses.[55]

In July 2018 the AER became responsible for calculating the price customers are prepared to pay for reliable electricity supply. The AER will estimate VCRs every five years based on consumer surveys, and update these annually. The values will have wide application, especially:

- in cost–benefit assessments such as those applied in regulatory investment tests
- in regulatory assessments of a network's investment forecasts in their revenue proposals
- as an input to assessing bonuses and penalties in the STPIS scheme
- in setting transmission and distribution reliability standards and targets
- to inform market settings such as wholesale price caps.

The AER will publish its first VCR estimates by December 2019.

3.15.3 Transmission reliability

Electricity transmission networks are engineered and operated to be extremely reliable, because an interruption may require the power system operator to disconnect a large number of customers (known as load shedding). To avoid this, the networks are engineered with sufficient capacity to provide a buffer against planned and credible unplanned interruptions to the power system.

Transmission reliability can be measured by indicators such as the number of lost supply events (figure 3.25) and the cost to customers of energy not supplied (figure 3.26).

Across the NEM, total loss of supply due to transmission failures has occurred no more than 30 times per year since 2006. Recent outcomes have been lower, with 11–12 events occurring each year from 2015–17. Tasmania accounted for a significant share of outages until 2013, but has since recorded similar outcomes to other jurisdictions. South Australia and Tasmania each recorded four of the NEM's 12 loss of supply events occurring in 2017.[56]

Another measures of transmission reliability is the value to customers of energy not supplied due to network interruptions. While unsupplied energy is a very small proportion of total electricity transported (generally less than

55 The Hon Josh Frydenberg MP, *Non-controversial rule change proposal—Making the AER responsible for values of customer reliability,* 21 December 2017.
56 AER, *Electricity Transmission Network Service Provider Performance data*, April 2018.

Figure 3.25

Transmission reliability—number of lost supply events

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

Source: AER, *Electricity transmission network service provider performance report*, 4 September 2018.

0.005 per cent), the cost of a transmission outage can be high (figure 3.26).

Network congestion imposed significant costs on the Queensland market in 2007 and 2009, while network outages in Victoria associated with bushfires imposed extreme costs in 2009. After a number of years of more stable outcomes, the cost of transmission outages moved higher in 2015 and 2016 for networks in Victoria, NSW and South Australia.

Transmission network congestion

Service performance criteria differ between transmission and distribution networks. For transmission networks, service performance criteria include the efficient management of network congestion and system reliability.

All networks have capability limits. Congestion issues arise when electricity flows on a network threaten to overload the system, requiring intervention to maintain power system security. A surge in electricity demand to meet airconditioning loads on a hot day may push a network close to its secure operating limits, for example.

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 dispatched instead, for example. Congestion, therefore, raises electricity prices by displacing low cost generation with more expensive generation. At times, congestion causes perverse trade flows, such as a low priced NEM region importing electricity from a region with much higher prices.

Transmission congestion caused significant market disruption in 2006, when rising electricity demand placed strain on the networks (figure 3.27). But significant investment from 2006–14—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.

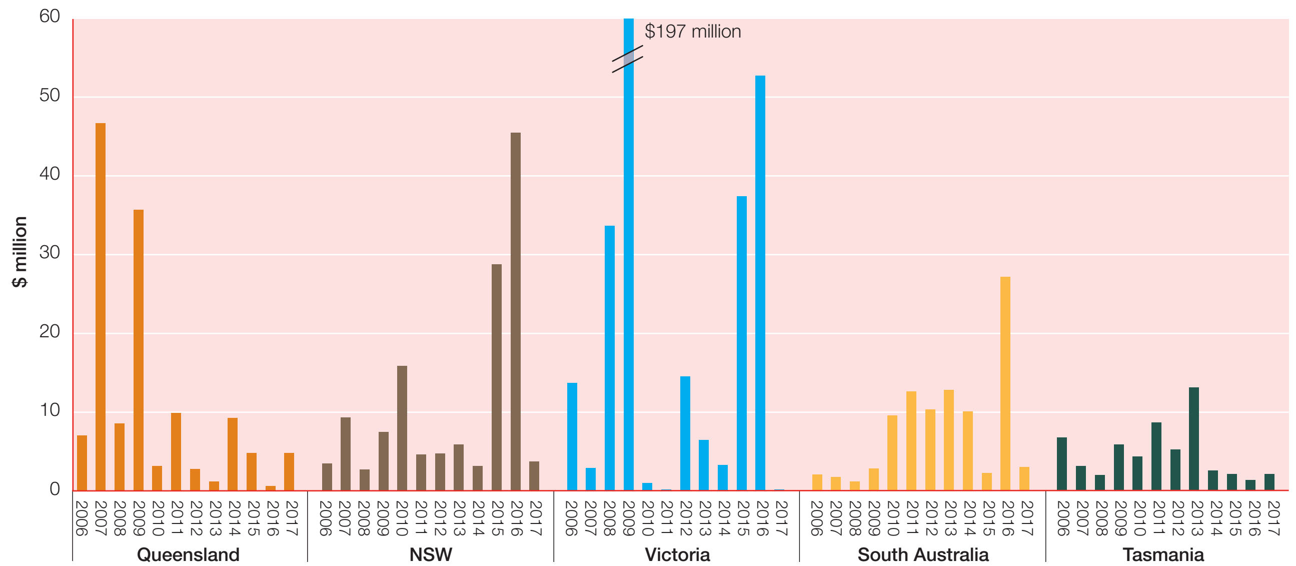
Higher congestion levels re-emerged from 2015, partly associated with outages associated with network upgrades in Queensland and on cross-border interconnectors linking Victoria with South Australia and NSW. Congestion was lower in South Australia in 2017 following completion of an interconnector upgrade.

Not all congestion is inefficient, however. Reducing congestion through investment to augment transmission networks is an expensive solution. Eliminating congestion is only efficient to the extent that the market benefits outweigh the costs of new investment.

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

Figure 3.26

Customer cost of energy not supplied due to supply interruptions



Note: Energy unsupplied includes major event days. Customer costs based on AEMO valuations of customer reliability made in 2014. Data is reported on a calendar year basis.

Source: AER, *2018 transmission network service provider benchmarking report*, p. 32; RINs submitted by network businesses.

3.15.4 Distribution reliability

In distribution, reliability—how effectively the network delivers power to its customers—is a central focus of network performance. Other aspects of network performance include complaints handling, timely notice of interruptions, promptness of new connections, call centre performance and the avoidance of wrongful disconnections.

Around 97 per cent of outages that electricity customers experience are due to issues in their local distribution network.[57] But the capital intensive nature of the networks makes it prohibitively expensive to invest in sufficient capacity to avoid all outages.

Reliability standards were historically set at high levels to protect customers from the cost and inconvenience of supply interruptions. Capital investment to ensure networks met those reliability standards drove network costs for several years. NSW and Queensland introduced more stringent reliability standards from around 2005, based on input methodologies that required significant investment. In contrast, Victoria placed more emphasis on reliability outcomes and the value customers place on reliability. A number of reviews found NSW and Queensland customers paid more than they should have due to unnecessarily high reliability standards. While Queensland and NSW began to relax reliability standards from 2014, the assets built to meet those high standards remain and customers continue to pay for them.[58]

Concerns that reliability driven investment was driving up power bills led the COAG Energy Council in 2014 to endorse a new approach to setting distribution reliability targets. The approach accounts for the value customers place on reliability, and the likelihood of interruptions.

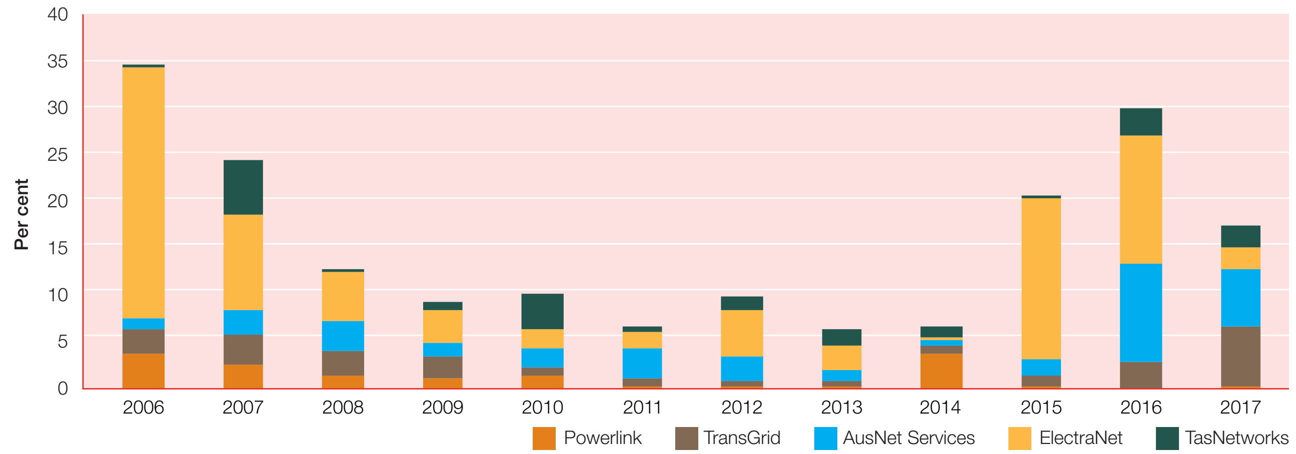
Several jurisdictions subsequently reformed their distribution reliability standards. The Queensland Government removed strict input based reliability standards in 2014. Similarly, the NSW Government removed deterministic planning obligations from network licence conditions. It introduced a new approach focusing solely on 'output' standards, to allow network businesses more discretion in determining how to meet reliability standards.

More recently, policy has focused on developing a consistent approach to estimating the value customers place on having a reliable electricity supply as a basis for setting standards (section 3.15.2).

57 Reliability Panel AEMC, *Annual market performance review 2017*, March 2018

58 ACCC, *Retail Electricity Pricing Inquiry—Final Report*, June 2018, p. 109.

Figure 3.27
Market intervals disrupted by transmission congestion



Note: Percentage of trading intervals each year where transmission network congestion impacted the NEM spot price by more than $10 per MWh. The data excludes outages caused by force majeure events and other specific exclusions.
Source: AER, *Electricity Transmission Network Service Provider Performance data*, April 2018.

The AER in 2018 examined setting up uniform distribution reliability measures across all jurisdictions to assess and compare the reliability performance of distributors. As part of this, it considered the extent to which outages beyond the control of a distributor should be excluded from the data—such as outages caused by the transmission network (which are currently usually excluded from reliability measures) and those caused by catastrophic events. It also explored new measures to capture the impact on customers most severely affected by outages.[59] The review will also inform revisions to AER incentives relating to network performance (section 3.15.5).

The AER in July 2018 also began work to estimate values of customer reliability. This work will have a range of applications, including as an input into setting reliability standards.

Distribution reliability indicators

Two widely used indicators of distribution reliability are:

- system average interruption duration index (SAIDI)
- system average interruption frequency index (SAIFI).

The SAIDI and SAIFI indicators measure the average duration and frequency respectively of unplanned outages experienced by distribution network customers. Figure 3.28 sets out data for each indicator. Comparisons across jurisdictions need to be made with care. In particular, the accuracy of businesses' information systems may vary. Environmental conditions and historical investment also differ across networks.

Across the NEM, a typical customer experiences around 250 minutes of outages per year, but outcomes vary between regions and over time. In particular, severe weather activity can affect reliability outcomes—cyclones affected a number of observations for Queensland, for example.

The average outage duration rose sharply in 2017 for South Australia, Queensland and NSW. South Australia's record outages reflect a state-wide blackout in September 2016. While the ACT has the lowest incidence of unplanned outage time in the NEM, outage duration also rose in 2017. Only Victoria and Tasmania recorded an improvement in outage duration, with Victoria recording its best performance in over a decade.

The frequency of unplanned outages generally declined over the past decade, with energy customers across the NEM typically experiencing around 1.5 outages each year. But outage frequency rose in South Australia, NSW and the ACT in 2017. The Victorian and Tasmanian networks reduced both the frequency and duration of power outages in 2017.

59 AER, *Draft distribution reliability measures guidelines, Explanatory statement*, June 2017.

Customer service by distributors

While reliability is the key service concerns for most customers, a distribution network's service performance also comprises:

- the timely notice of planned interruptions
- the quality of supply, including voltage variations
- wrongful disconnection and timeframes for reconnection
- being on time for appointments
- response time for fault calls
- the provision of fault information.

Individual jurisdictions set different service standards for these performance measures. Some jurisdictions apply guaranteed service level (GSL) schemes that require network businesses to compensate customers for inadequate performance. As reporting criteria vary by jurisdiction, performance outcomes are not directly comparable. The AER provides an annual summary for jurisdictions covered by the National Energy Retail Law (NSW, Queensland, South Australia, Tasmania and the ACT).[60] Victoria reports separately on performance.[61]

Between January 2017 and 30 November 2018, the AER issued 24 infringement notices to distribution businesses for failures to provide sufficient notice of outages to life support customers. Eight notices were issued to Energex (Queensland), six notices to Ausgrid (NSW), seven notices to TasNetworks (Tasmania), three notices to Evoenergy (ACT). The AER also accepted administrative undertakings from Energex and TasNetworks and a court enforceable undertaking from Ausgrid committing to improving their procedures and processes relating to life support customers.

3.15.5 Incentivising good performance

The AER runs incentive schemes that encourage good network performance. The schemes pay bonuses for good performance, and in some cases, apply penalties for underperformance.

Transmission incentives

The AER operates a service target performance incentive scheme (STPIS) that encourages transmission businesses to improve network performance in ways that customers value. It is designed as a counterbalance to the EBSS (section 3.13), to ensure businesses do not unreasonably cut operating and maintenance spending at the expense of service quality. The AER sets separate targets reflecting the circumstances of each network based on its past performance:

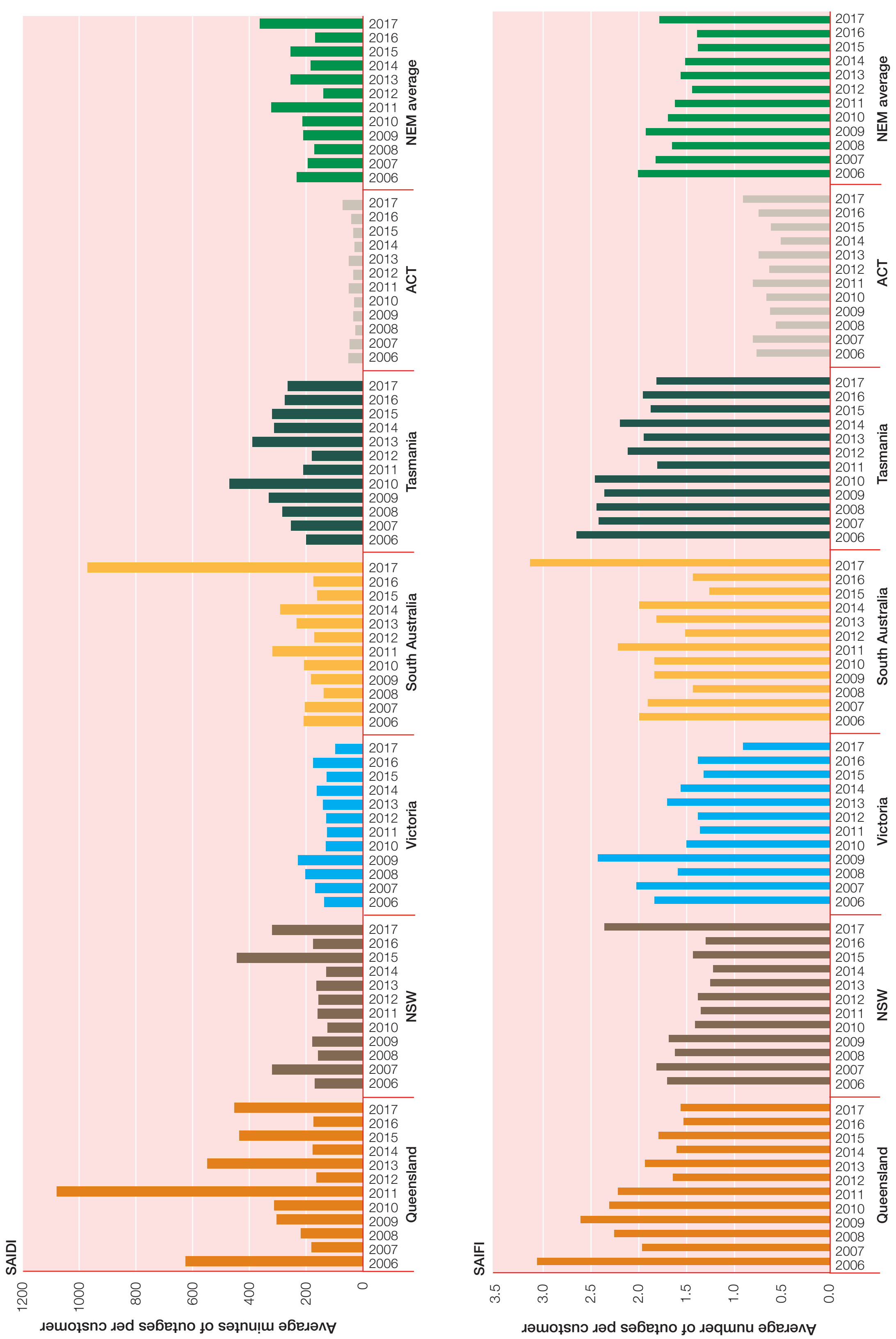
- A *service* component sets targets for the frequency of supply interruptions, outage duration, and the number of unplanned faults on the network.
- A *market impact* component encourages businesses to improve their operating practices to reduce network congestion—for example, by scheduling outages to minimise network disruption. A network business can earn bonuses/incur penalties of up to 1 per cent of its regulated revenue by eliminating outages with a market impact of over $10 per megawatt hour.
- A *network capability* component funds one-off projects to 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. AEMO helps prioritise projects that deliver best value for money to consumers, and the AER approves a project list. Network businesses can earn bonuses each year, but may face a penalty of up to 2 per cent of revenue in the final year of their regulatory period if they fail to achieve improvement targets.

The results are standardised for each network, to derive an 's factor' that can range from –1 (the maximum possible penalty) to +4.5 (the maximum possible bonus).

While performance against individual component targets varies, the networks have generally earned bonuses for above target performance.[62] The Murraylink (in 2016) and Directlink (in 2016 and 2017) interconnectors were the only networks to incur penalties for below target service performance in the past two years. Most networks performed above target on congestion management (market impact) and network capability targets. In total, the NEM's transmission networked earned around $57 million in performance bonuses in 2016, and $50 million in 2017.

60 AER, *Annual report on compliance & performance of the retail energy market 2016–17*, November 2017, appendix 3.
61 See, for example, Essential Services Commission 2017, *Victorian Energy Market Report 2016–17*, November 2017.
62 Service standards compliance reports for each network are available at www.aer.gov.au.

Figure 3.28
Electricity supply reliability



Note: The data reflects total *unplanned* outages experienced by distribution customers, including outages originating in generation and transmission networks. The data is *not* normalised for outages beyond the network operator's reasonable control. Data is for the 12 month period ending 30 June for all states except Victoria. Victorian data is for the calendar year ending in that period.
Source: AER economic benchmarking RINs.

3.16 Distribution incentives

The AER launched a STPIS for distribution networks in 2009, aimed at aligning network reliability with customers' valuations of that reliability. The STPIS sets targets for the average duration and frequency of outages based on a business's past performance, which is normalised to exclude interruptions beyond the network's reasonable control. The STPIS also accounts for customer service and faults, and call centre performance. A GSL component requires network businesses to pay customers if their performance falls below threshold levels. Performance outcomes are converted to an 's factor' reflecting deviations from targets.

The incentive scheme provides financial bonuses (and penalties) for network businesses that meet (or fail to meet) performance targets. The default bonus or penalty is 5 per cent of revenue. While the scheme aims to be nationally consistent, it has flexibility to deal with the operating environment of each network, resulting in larger bonuses or penalties in some instances. Outcomes are rewarded or penalised via the AER's annual tariff reviews for each network.

The SPTIS performance targets are adjusted every five years, based on the recent performance of each distribution business. Improvements in service performance will result in the benchmark performance targets being tightened in future years. A distributor must, therefore, maintain reliability improvements to continue benefitting under the scheme.

The STPIS has been applied to Victorian distribution networks since 2011. Among all the Victorian businesses, only Jemena has outperformed its targets every year.

Queensland networks Energex and Ergon Energy have exceeded their performance targets each year since the scheme was applied in 2012. South Australian and Tasmanian networks have also outperformed their targets in most years since the scheme commenced in 2012 and 2013 respectively. For ACT and NSW networks, the STPIS was first applied for the 2015–19 regulatory period.

The AER reviewed the scheme in 2018, examining how financial bonuses and penalties are calculated and how renewable energy and distributed generation affect the scheme's operation.

Victoria's distribution 'f factor' scheme

The AER administers a Victorian Government scheme offering incentives to Victorian distributors to lower the number of fire starts originating from their network. This 'f factor' scheme provides strong incentives to reduce the number of fire starts in high fire danger zones and times. Incentives may be as high as $1.48 million per fire start avoided in high risk areas on a code red day. But if the number of fire starts rises, the networks pay a penalty.

All businesses outperformed their benchmark targets during 2016–17.[63] Incentive payments varied from around $43 000 for the small, predominantly urban CitiPower network, to $4.6 million for the large and predominantly rural Powercor network.

Distributors will only continue to receive payments if they make sustained and continuous improvements in fire start performance. Once improvements are made, the benchmark fire start targets are tightened in future years.

63 AER, *Victoria F-factor scheme results for 2016–17 reporting period*, Media release, 29 June 2018.