Electricity network performance report

July 2023

AUSTRALIAN ENERGY REGULATOR

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne VIC 3001

Tel: 1300 585 165

Email: networkperformancereporting@aer.gov.au

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Contents

1 Overview

This is the AER's fourth annual network performance report ('the report') for electricity networks. In the report, we have identified and analysed key outcomes and trends in the operational and financial data we collect from electricity distribution and transmission network service providers (DNSPs and TNSPs, or collectively, NSPs). Since 2021, we have also prepared similar performance reports for fully regulated gas networks.

Through our network performance reports, we aim to provide accessible information that improves transparency and accountability around network performance under the regulatory regime. Comparing actual network performance against forecasts helps to identify and understand the effectiveness of the regulatory regime; thereby supporting informed engagement and data-driven debate.

We consider network regulation has improved outcomes for consumers over time. In 2021 and 2022, consumers on average paid less for electricity network services than in any other year since 2010. At the same time, outages have been less frequent and NSPs have remained profitable. While there have been clear improvements in consumer outcomes since our major regulatory reform package in 2013[1], consumers have also benefited from an external environment comprising low interest rates and inflation. However, the external environment is starting to shift, increasing the importance of the AER's commitment to monitor performance and making energy consumers better off, now and in the future.

Key findings:

- Network revenue is largely stable with only a marginal increase in 2022. Revenue in 2021 and 2022 was lower than any other year since 2010. Factors outside network's and our control (higher interest rates and inflation) will likely result in further increases in future years.
- Network reliability was high in 2022 relative to most previous years, although distribution outages in the National Electricity Market were both longer and more frequent than in 2021, when reliability was particularly high (Section 3.4).
- Networks achieved a lower return on assets in 2022 compared to 2021. This reflects lower returns to networks for their investments in assets, more closely aligning with our targeted values. The return on assets measures the returns that NSPs were able to earn from using their regulated asset base as a whole.
- Networks achieved a higher return on regulated equity in 2022 compared to 2021. A major driver of increased return on regulated equity in 2022 was increased inflation, which has changed from causing downwards pressure on returns on equity to causing upwards pressure on returns on equity (Section 4.3). The return on regulated equity

1 AER, *Better Regulation*, Accessed 24 April 2023.

measures the returns NSPs were able to earn from the part of the regulated asset base that is financed by equity. It is influenced by the financing decisions of the NSP.

- NSPs' total expenditure decreased from 2021 and was 15% below forecast. Lower than forecast expenditure was in part due to a reprofiling of expenditure on the SA-NSW interconnector (Section 3.2).
- NSPs have on average been spending less than our operating expenditure (opex) forecasts since 2018. NSPs also reported higher rewards from incentive schemes in 2022 with consumers benefiting from efficiency gains through lower prices (Section 3.1.3).
- Regulatory asset base (RAB) per customer decreased by 1% since 2021. We expect transmission network RABs per customer to grow in the future as several major projects are being developed (Section 3.3).
- In 2022, average distribution network utilisation was 42%. Since 2015, annual movements in network utilisation have mainly been driven by changes in maximum demand, with little change in zone substation transformer capacity.
- Maximum demand increased slightly in 2022 following a decrease in 2021. Increased penetration of consumer energy resources and improved energy efficiency is likely to have dampened maximum demand, with other drivers such as weather effects contributing to annual variation.
- The proportion of customers on cost reflective tariffs is increasing. Given the ubiquity of smart meters in Victoria, the proportion of Victorian customers on cost reflective tariffs is relatively low. This is partly because the early timing of the Victorian roll-out meant that 'opt-in' approaches to cost reflective tariffs applied to most Victorian customers (noting that opt-out approaches are available to new customers in Victoria).

Our analysis focuses on core regulated services, which are the main energy transport services provided by NSPs using the network assets in their RABs.[2] These services are called:

- Standard control services for electricity DNSPs
- Prescribed transmission services for electricity TNSPs.

An effective network regulatory regime contributes to consumers paying no more than is necessary for a safe and secure supply of energy. Implicit in this vision is a balance between the costs of providing network services and the outcomes arising from those costs. We have structured the report to systematically consider whether this balance is being achieved. We encourage stakeholders to read this report alongside our annual benchmarking report, which reports on NSPs' productive efficiency.[3]

2 While NSPs also provide and collect network revenue for other services, these sit outside the revenue cap and can be subject to other forms of regulation or, in some cases, unregulated.

3 AER, *Annual Benchmarking Report – Distribution and Transmission 2022*, accessed 7 June 2022.

1.1 Focus areas and export service performance reporting

Our network performance reporting balances regular high-level reporting on a core set of measures with more detailed analyses on focus areas representing emerging issues of stakeholder interest.

Our 2023 network performance report focuses exclusively on core measures. In December 2023, following our receipt of data relating to export services, we will issue an update of this report and include a chapter that meets the requirements of the inaugural export performance report.[4] Export service performance will be a new and substantial piece of analysis that will form part of our regular reporting as we develop annual export performance reports. This approach aligns with what we consulted on during our incentivising and measuring export service performance review.[5]

We aim to choose new and relevant focus areas each year to reflect important emerging issues and stakeholder interest. To best target those choices, we encourage direct feedback on future topics or emerging issues of interest. For background and to guide readers who wish to revisit any of our analysis, Table 1-1 summarises our previous focus areas.

Table 1-1 Previous focus areas

Report	Focus area	Outcome
2022	• Major events and expenditure impacts over time • Network safety development (continued) • Progress on tariff reform	• One-off analysis, although subsequent reports broaden the analysis on cost pass throughs • Subsequent reports include a safety section • Subsequent reports include smart meter and cost reflective tariff penetration
2021	• Impact of COVID on consumption and revenue • Seasonal reliability and the 19/20 summer bushfires • Network safety development • Introduction of the return on regulated equity	• One-off analysis • Segued into analysis on major events • Segued into 2022 focus area • Subsequent reports include returns on regulated equity
2020	• Impact of incentive scheme payments • Introduction of earnings before interest and tax (EBIT) per customer • Relationship between utilisation and reliability • Network investment: composition, timing, and performance relative to forecasts	• Informed incentive review[6] • Subsequent reports include EBIT per customer • One-off analysis • Introductory analysis informing incentive review and network expenditure as a core measure

Source: AER network performance reports.

1.2 Stakeholder engagement on the report

Before developing our first network performance report we undertook extensive stakeholder engagement to:

4 Export performance reports are formally referred to as "DER network service provider performance reports" under Rule 6.27A of the National Electricity Rules. These can be included within an existing AER network performance report and must be published annually, with the first report required by the end of 2023.

5 AER, *Incentivising and measuring export services performance*, accessed 7 June 2023.

6 AER, *Review of incentive schemes for regulated networks*, accessed 7 June 2023.

- Develop priorities and objectives for reporting on network performance[7], also set out in Appendix A.
- Complete our profitability measures review, which has been an important input into our network performance reports.[8]

In developing this 2023 report, we:

- Sought early input from a cross-section of consumer and industry stakeholders on focus areas to explore in this report.
- Gave NSPs an opportunity to review the accuracy of our key data sources.
- Gave NSPs, consumer representatives and other relevant stakeholders an opportunity to review and engage with our analysis.
- Engaged with state and territory safety and technical regulators on the accuracy of the safety analysis within the report.

7 AER, *Objectives and priorities for reporting on regulated electricity and gas network performance 2020*, 2020.

8 AER, *Profitability measures for electricity and gas businesses*, 2019.

2 Context for the 2023 report

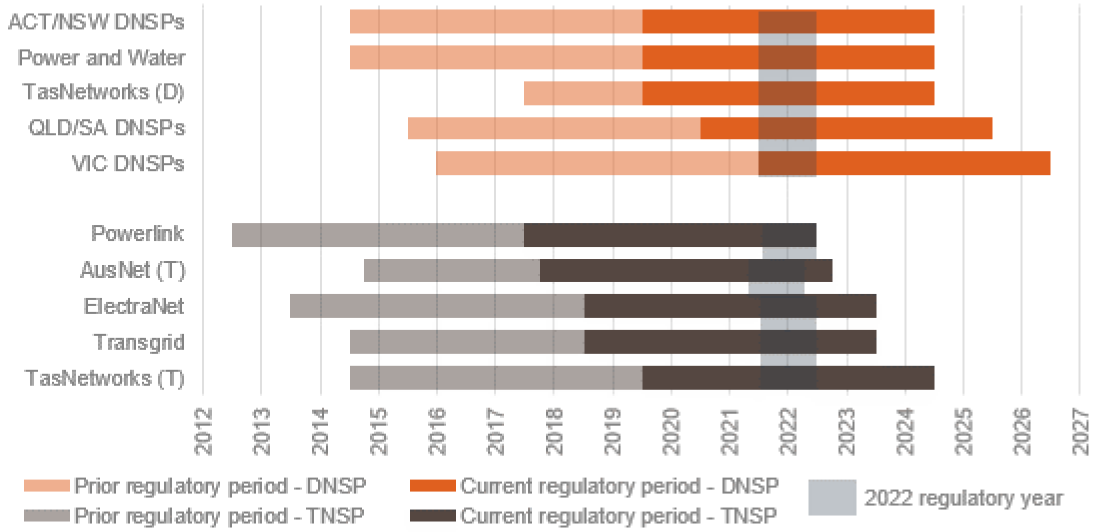
The 2023 network performance report covers network data for regulatory year 2022, which is:

- April 2021–March 2022 for AusNet (transmission) (Victoria); and
- July 2021–June 2022 for all other NSPs

Unless otherwise stated, all financial values are presented in real 30 June 2022 dollar terms to enable comparisons over time.

Generally, our regulatory determinations apply over 5 years made in a staggered cycle. Due to this, changes in regulatory approaches or market conditions affect NSPs gradually.

Figure 1 The staggered revenue decision timetable



Source: AER analysis of regulatory determination periods available on AER website.

For convenience, we think of regulatory cycles as commencing with determinations for the DNSPs in NSW, ACT, Tasmania, and the Northern Territory. These determinations affect a notable proportion of regulated NSPs and have historically been the first major decisions to incorporate substantial changes in regulatory settings (for example, 2013 better regulation reforms and the 2018 rate of return instrument).

2.1 Reporting on Northern Territory Power and Water Corporation

In 2019, we made our first determination for Power and Water Corporation (Power and Water), the Northern Territory's DNSP. Regulatory year 2022 is the third year of its first regulatory control period under an AER determination. Unless otherwise specified in the report, we have included Power and Water data in our report. Where the relevant data series is relatively simple—for example historical RAB trends—we have included historical Power and Water data in our existing data series for continuity.

3 Operational performance in 2022

This section looks at the following core performance outcomes:

- network revenue—the cost to consumers of network services (section 3.1)
- network expenditure (section 3.2)
- RAB (section 3.3)
- network service outputs related to reliability (section 3.4)
- network safety (section 3.5)
- distribution network utilisation (section 3.6)
- progress of tariff reform and enabling technology (section 3.7)

We also look at:

- how outcomes in 2022 relate to longer term trends across network performance measures
- where relevant, how those outcomes compare to forecast amounts.

This section does not directly investigate whether the relationships between network expenditure and service outputs are productively efficient. Rather, our benchmarking reports directly measure how productively efficient NSPs are delivering core regulated services over time compared with their peers. Our benchmarking reports are published in November each year.[9]

This performance report more directly explores the costs and profitability of providing core regulated services, which are consequences of NSPs' productive efficiency, capital market conditions and our regulatory settings. Regulatory settings include how we forecast expenditure and share the rewards or penalties of network performance between NSPs and consumers.

3.1 Network revenue—the cost to consumers of network services

The total revenue NSPs recover is an informative measure of how core network services are contributing to consumers' bills. However, it is complex to make general observations about the impact of network costs on specific consumer bills. One complexity is that the proportion of total revenue collected from different types of consumers varies between NSPs and over time. Another complexity is that most electricity consumers pay network costs via a retailer, where they are combined with other costs of supplying energy.

In addition to recovering the costs of core network services, DNSPs must also recover other costs from consumers, such as the costs of jurisdictional schemes, which we typically do not have a role in setting.[10] Some of these schemes, such as jurisdictional solar bonus schemes, are not included in the revenue building blocks. For this section, 'network costs' refers only to costs arising from:

9 Our benchmarking reports published last year are available at AER, *Annual benchmarking reports 2022*, November 2022.

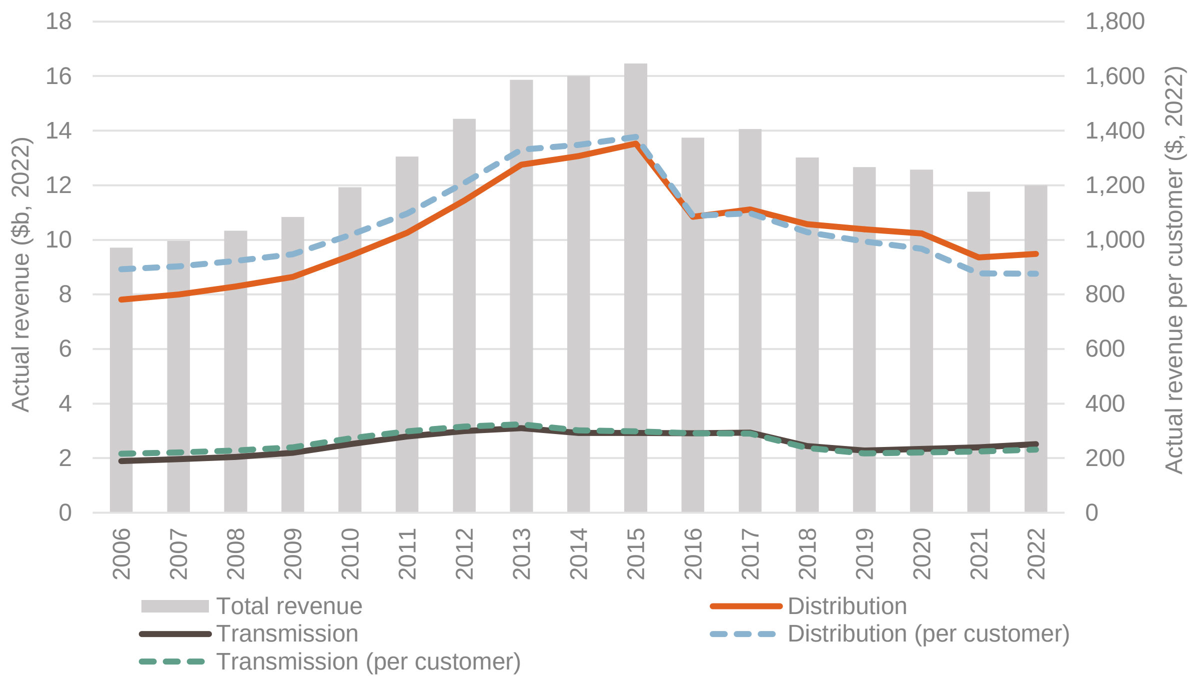
10 While we have traditionally not had a role in setting the costs to recover under jurisdictional schemes, we have recently adopted the role of determining the jurisdictional costs associated with renewable energy zones in NSW.

- DNSPs providing standard control services, and
- TNSPs providing prescribed transmission services.

3.1.1 Actual network revenue

Network revenue is largely stable with only a marginal increase in 2022. Revenue in 2021 and 2022 was lower than any other year since 2010.

Figure 2 Total core regulated network service revenue recovered from consumers - DNSPs and TNSPs



Source: Annual RIN table 8.1.1.1, 'Revenue – Standard control services' for DNSPs. For TNSPs or where Annual RIN data is not available for DNSPs, data is from Economic Benchmarking RIN table 3.1.1, 'Revenue grouping by chargeable quantity'.

Notes: AER calculation to convert to $ June 2022 values.

The overall downward trend in network revenue since 2015 means that consumers, in total, have been paying less for the network component of their bills since this time. Growth in customer numbers amplifies this effect on an individual customer basis. Consumers' bills are also made up of several other components, including wholesale market costs, retail margins and jurisdictional costs. Further information on these other bill components is set out in our State of the Energy Market report[11], and in our regular wholesale and retail reporting.[12]

11 All versions of State of the energy market are available at AER, *State of the energy market reports*, accessed 7 June 2022.

12 AER, *Performance reporting (wholesale markets)*, accessed 3 June 2022; AER, *Performance reporting (retail markets)*, accessed 7 June 2022.

3.1.2 Drivers of network revenue

All electricity NSPs are now regulated under revenue caps.[13] NSPs annually set their prices to target earning the maximum revenue allowed under the revenue cap. We set the maximum allowed revenue so NSPs can recover the costs of an efficient network providing core regulated services. These are determined as 'building blocks'. Figure 3 illustrates how these building blocks fit together, with Figure 4 highlighting trends in how each building block has contributed to revenue over time. The building blocks include:

- A return on the RAB (or return on capital, to compensate investors for the opportunity cost of funds invested in the NSP). This is the largest building block. It has also been the main driver of lower forecast revenue since 2014 when we approved our approach to setting allowed rates of return and entered an external environment with low interest rates.[14] While we continue to improve our approach to setting allowed rates of return, we are also now moving to a more challenging external environment with higher interest rates. We will closely monitor and report on the net effect of these changes in future reports.[15]
- Depreciation of the RAB (or return of capital, to return the initial investment to investors over time). This building block has been steadily increasing since 2013.
- Forecast capex incurred in providing network services, which then enters the RAB and is depreciated over the economic life of the asset.
- Forecast opex incurred providing network services. This building block declined after we introduced benchmarking to re-base the opex allowances for less efficient NSPs[16], after which it has remained steady.
- The estimated cost of corporate income tax. This building block has declined over time but has a relatively small impact on overall revenue.
- Revenue adjustments, including revenue increments or decrements resulting from applying incentive schemes. These can be positive or negative and do not show a clear trend to date.

We update the revenue targets each year to account for actual inflation, changes in the NSPs' allowed returns on debt, cost pass throughs and other factors. As well as interest rates, inflation is a factor outside NSPs' and our control that will place upwards pressure on NSPs' allowed revenue in future years.[17]

13 The last network to be moved to a revenue cap was Evoenergy at the commencement of its 2019–24 regulatory control period.

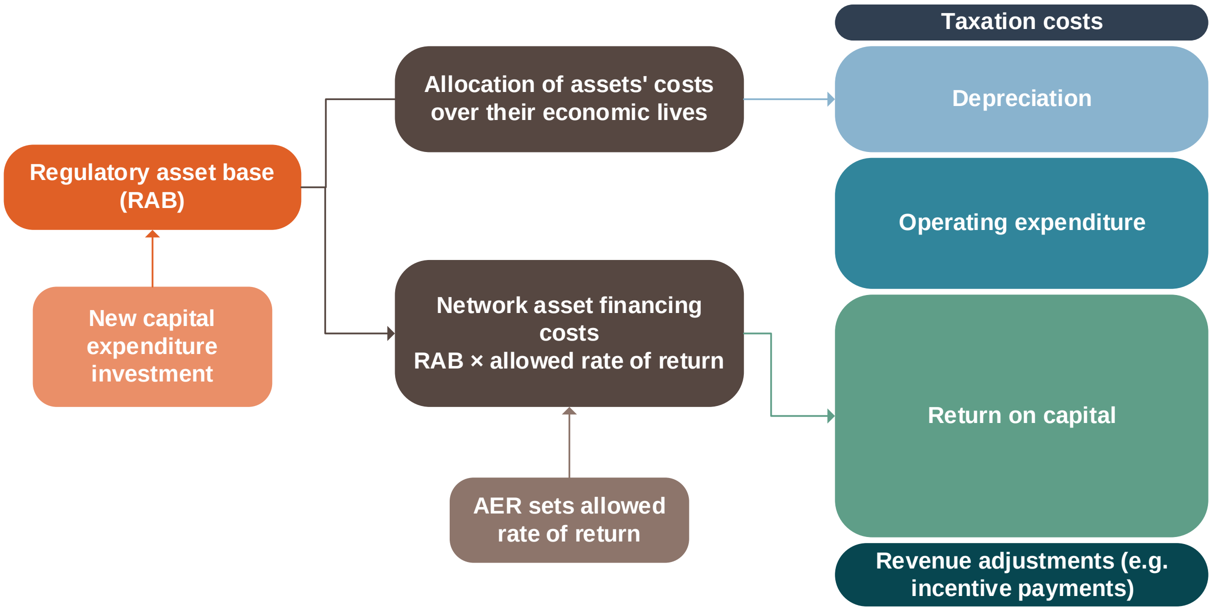
14 AER, *Better regulation: Rate of return guideline*, December 2013.

15 AER, *Rate of return instrument 2018t*, December 2018; AER, *Rate of return instrument 2022*, February 2013; AER, *Rate of return – Overview for customers*, February 2023, p. 2.

16 AER*, Expenditure forecast assessment guideline 2013*, updated 1 August 2022, accessed 24 April 2023.

17 AER, *Rate of return – Overview for customers,* February 2023, p. 2.

Figure 3 The building block model to forecast network revenue



Source: AER analysis, adapted from AER, *State of the Energy Market*, December 2018, p.138.

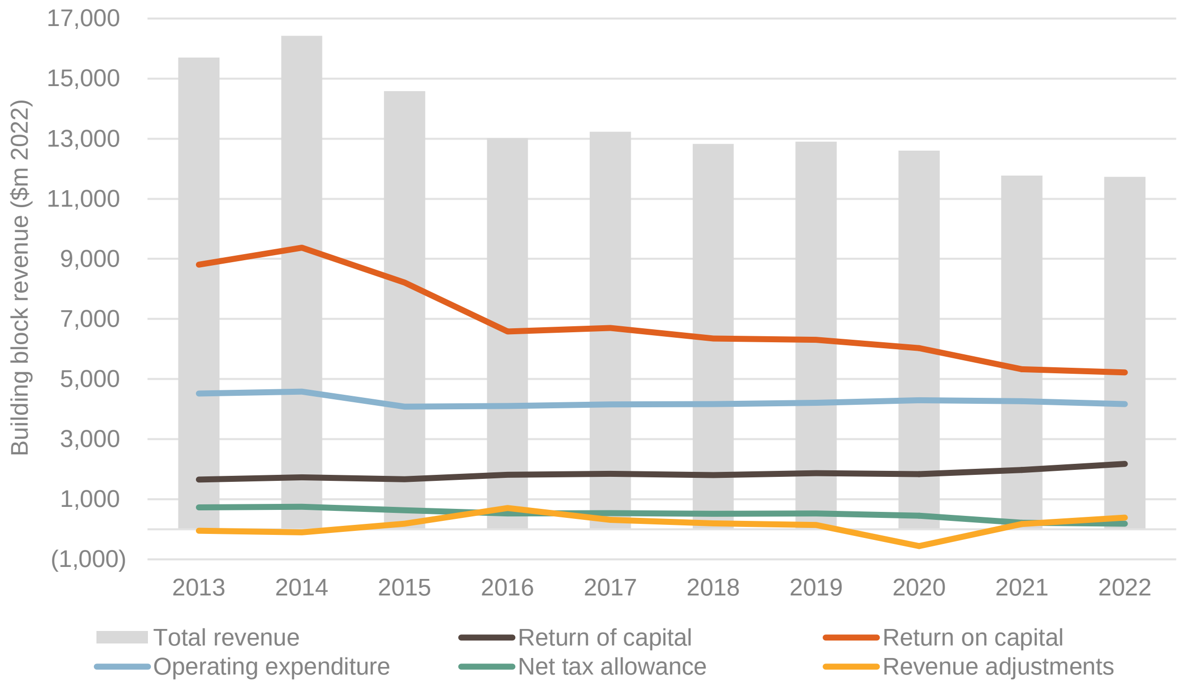
In 2022, forecast network revenue declined by 0.4%.[18] There were minimal changes in individual building blocks, with most declining slightly and return of capital (depreciation) rising slightly (Figure 4).

Figure 4 reflects the impacts of the 2018 rate of return instrument and 2019 tax review, which have been feeding into lower forecast return on capital and tax building blocks over the last few years.[19] Prevailing interest rates in debt markets also affect revenue allowances through our annual updates to the return on debt.

18 Forecast network revenue presented here is based on building block revenue from the PTRM and is "unsmoothed". This is not directly comparable to the smoothed forecast revenue that is published alongside this report.

19 The impact of allowed rates of return on NSPs was discussed in detail in AER, *2020 electricity network performance report*, 2020.

Figure 4 Forecast building block revenue components —NSPs



Source: PTRMs, 'Revenue summary – Building block components'.

Notes: AER calculation to convert to $ June 2022 values.

3.1.3 Revenue from incentive schemes

We incentivise NSPs to outperform our revenue allowances by ensuring they keep a share of profits or losses. In addition, we also apply targeted incentive schemes that encourage NSPs to improve efficiency, reliability, and other desirable outcomes, thereby delivering better outcomes for consumers.[20] To date, NSPs have received rewards or penalties under the following incentive schemes:

- efficiency benefit sharing scheme (EBSS)
- service target performance incentive scheme (STPIS)
- demand management incentive scheme (DMIS) for the DNSPs
- F-factor scheme for the Victorian DNSPs[21]
- capital expenditure sharing scheme (CESS)
- customer service incentive scheme (CSIS)[22]

We recently reviewed our incentive schemes and guidelines to ensure they remain relevant and fit-for-purpose. Following the review, the AER found 'incentive schemes have improved network

20 The revenue impact of incentive schemes was a focus area in AER, *2020 electricity network performance report*, 2020.

21 The Victorian Government introduced the 'f-factor scheme' on 23 June 2011, which incentivises DNSPs to reduce the risk of fire starts and the loss or damage they cause. This incentive scheme was implemented following the 2009 Black Saturday bushfires.

22 CSIS first applied in 2022 to AusNet Services, CitiPower, Powercor and United Energy. These DNSPs received rewards ranging from $0.8–3.8 million. AER, *Assessment of customer service incentive scheme 2021-22*, accessed 7 June 2023.

efficiency, reduced costs, and, with some refinements, stand to benefit energy consumers even further'.[23] Some of these refinements include amending the CESS to adopt tiered sharing ratios and to be applied to contingent projects at our discretion, which will apply to NSPs from the start of their first regulatory period after April 2023.[24] We also committed to review elements of the transmission STPIS and our benchmarking approach.[25]

In 2022:

- As a result of increased efficiency in expenditure to the long-term benefit of consumers, NSPs reported higher overall rewards from incentive schemes than in 2021.
- For DNSPs, higher efficiency in capital expenditure and operational expenditure resulted in higher rewards under the CESS and EBSS respectively. Although lower incentive payments were reported for meeting service performance targets through the STPIS. Consumers benefit from expenditure efficiency improvements through lower prices.[26]
- For TNSPs, improvements in operational expenditure efficiency resulted in higher rewards under the EBSS and improvements in meeting network performance targets led to higher rewards under the STPIS. While these rewards were higher than in 2021, they are modest compared to most previous years.
- NSPs are beginning to report incentive payments for improved capital expenditure efficiency under the CESS. These payments are likely to increase for networks that are improving capital expenditure efficiency as more NSPs enter new regulatory control periods.

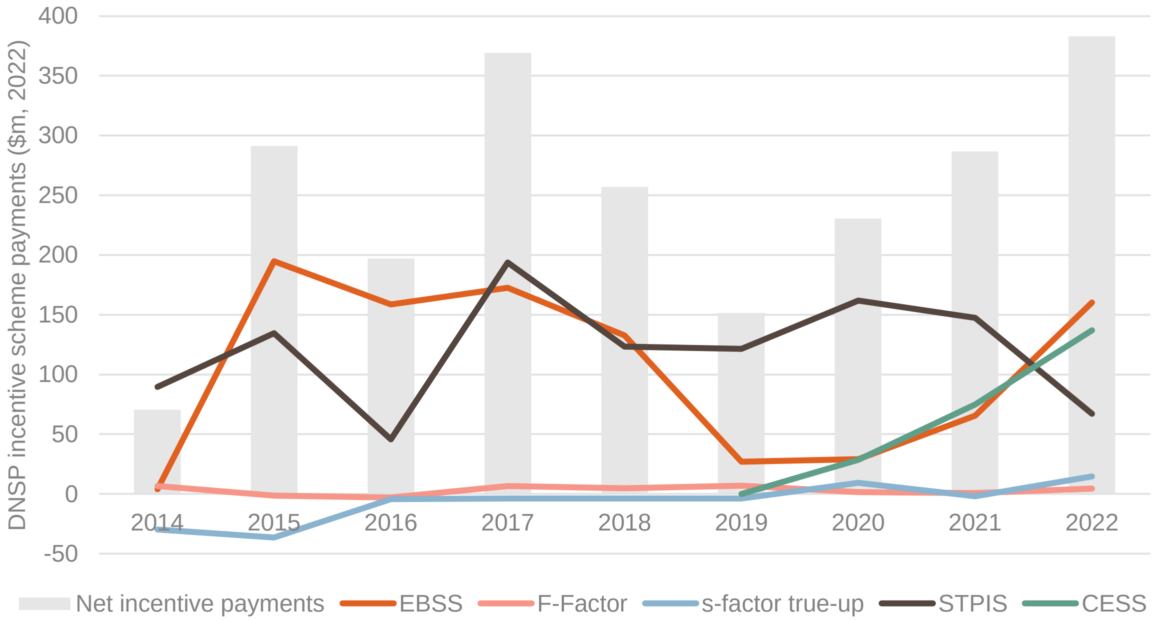
23 AER, *News release: Review finds incentive schemes drive network efficiency up and expenditure down*, 1 May 2023, accessed 7 June 2023.

24 AER, *Capital expenditure incentive scheme guidelines for electricity network service providers*, April 2023, p. 1.

25 AER, *Review of incentives schemes for networks: Final decision*, April 2023, pp. 5-6.

26 AER, *Review of incentives schemes for networks: Final decision*, April 2023, p. 4.

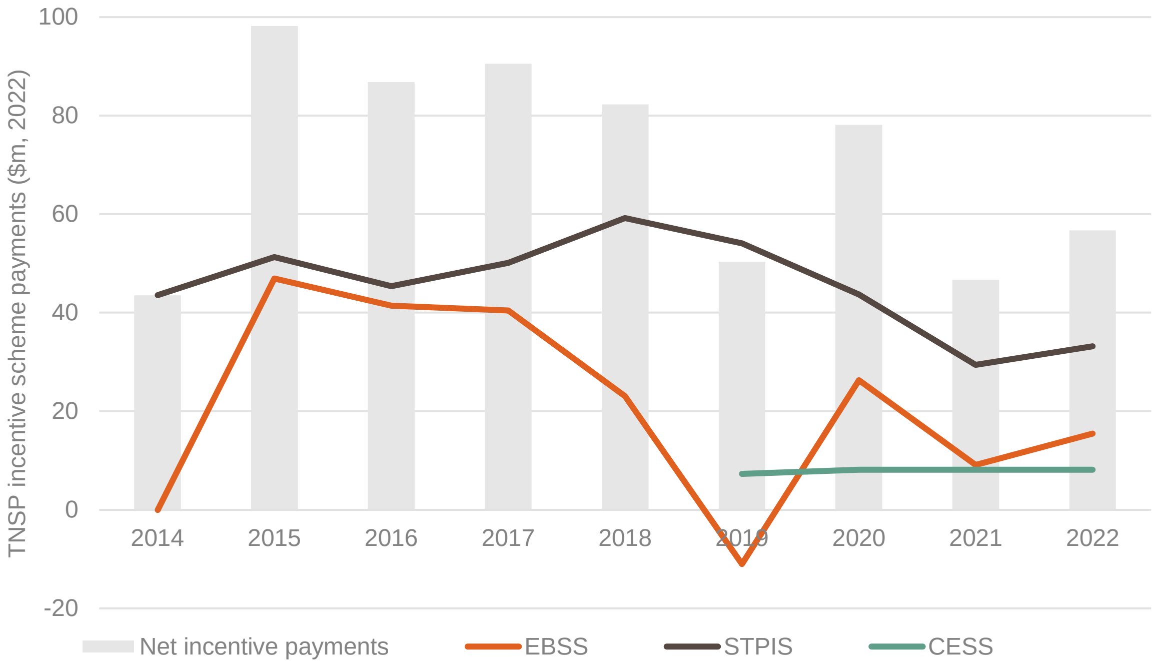
Figure 5 Reported incentive scheme payments – DNSPs



Source: Economic Benchmarking table RIN 3.1.3 excluding 'other' incentive payments. CESS is sourced from PTRM 50.11.

Note: Excludes incentive scheme payments that have a minor impact, such as the DMIS. AER calculations to convert values to $ June 2022.

Figure 6 Reported incentive scheme payments – TNSPs



Source: Economic Benchmarking table RIN 3.1.3 excluding 'other' incentive payments. CESS is sourced from PTRM 50.11.

Note: AER calculations to convert values to $ June 2022.

3.1.4 Revenue from cost pass throughs

In this section, we report revenue approved in cost pass through applications lodged before the end of the 2022 regulatory year.

In 2022:

- Nearly $50 million of costs were passed through to electricity consumers through the cost pass through mechanism.
- We received 14 cost pass through applications, which is more than what we have received in any previous year. These included 4 network support cost pass throughs – one for each of the TNSPs.[27]

Cost pass throughs are a mechanism within the regulatory framework that require us to adjust allowed building block revenues following unforeseen changes in an NSP's costs that are outside of its control.[28] Costs associated with these events must be material in the sense they exceed 1% of the allowed revenue an NSP can earn in that regulatory year. These adjustments can be positive (to increase forecast revenues) or negative (to decrease forecast revenues). NSPs recover pass through costs in different ways, including:

- Recovering more revenue from customers through adjusting the forecast revenues from the building block determination. This includes recalculating the allowances for opex, return of capital, return on capital and taxation costs. We have previously considered consumer preferences when determining over how many years the NSP should recover revenue.[29]
- Including more capex in their RAB in the same manner as other capex. This increased capex is not recovered from customers in the cost pass through application, but rather in future regulatory years though the return of capital building block. We have not included this amount in Figure 7.

Cost past through events are prescribed in the National Electricity Rules and include the event category, 'events specified in a regulatory determination'.[30] This category reflects that NSPs can nominate additional pass through events to apply for their regulatory control period. One of our considerations behind accepting nominated pass through events is whether expenditure beyond a certain point (such as eliminating, rather than managing risk) is likely to be imprudent or inefficient. For example, we have allowed natural disaster events as nominated cost pass through events. While NSPs can take steps to minimise the cost impacts of natural disasters should they occur, it

27 Under the NER, cl. 6A.7.3 a Network support cost pass through (positive or negative) applies where a network support event occurs with respect to a regulatory year. A network support event occurs when the amount of network support payments made by a TNSP for a previous regulatory year is higher or lower than the amount of network support payments (if any) that is provided for in the annual building block revenue requirement for the TNSP for that regulatory year.

28 Under NER cl 6.6.1 for DNSPs and NER cl 6A.7.3 for TNSPs.

29 For example, see AER, *Determination: Cost pass through – Essential Energy's 2019–20 bushfire natural disaster events*, 2022, p. 18; AER, *Decision: Cost pass through – AusNet Services' 2019-20 bushfire natural disaster event*, November 2020, pp. 14–15; AER, *Decision: Cost pass through - Endeavour Energy's 2019-20 bushfire natural disaster event*, February 2021, p. 15.

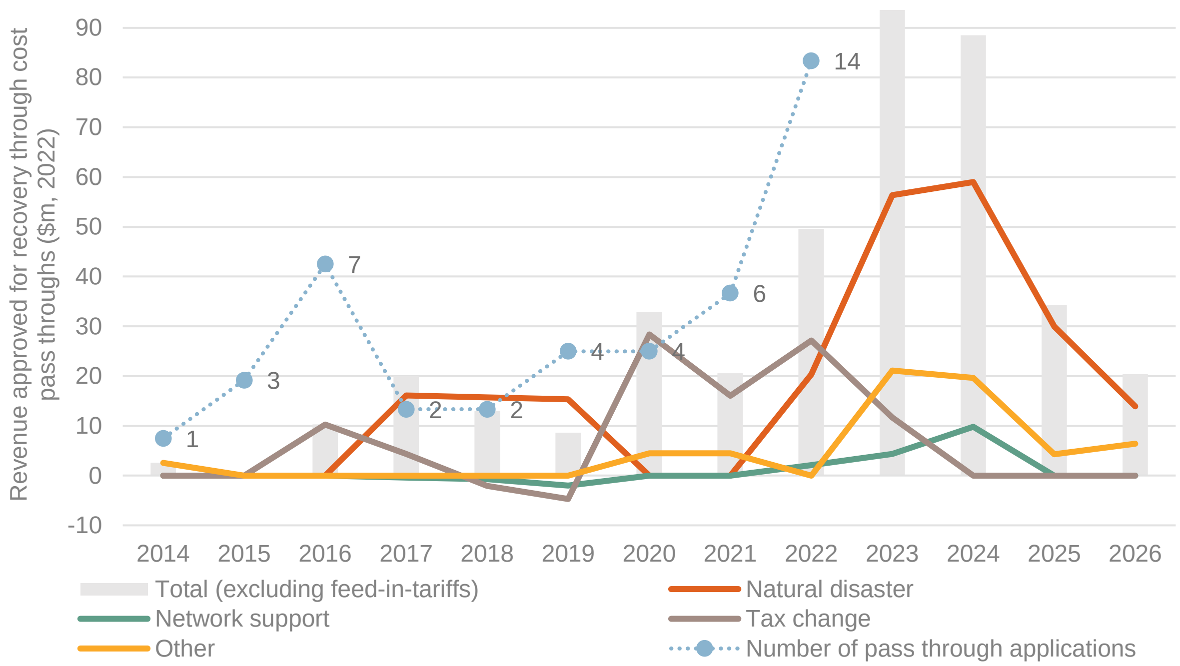
30 NER clauses 6.6.1(a1), 6A.7.3(a1) and 6A.7.2.

is often more cost effective to rapidly respond to events than to build out the network in a way that eliminates the cost impacts of all potential natural disasters, which is also unlikely to be possible to do in practice.

Figure 7 shows the revenue approved in cost pass through applications lodged before the end of the 2022 regulatory year. We also received at least 10 cost pass through applications in the 2023 regulatory year. When interpreting Figure 7, readers should note that this analysis:

- Excludes the $440 million and $384 million of feed-in-tariff costs passed through to Queensland consumers in 2016 and 2017 respectively. As these amounts were much larger than other pass through amounts, including them would make it difficult to view changes in other revenue streams.
- Reports values differently to our previous analysis on natural disaster cost pass through applications.[31] While our previous analysis reported pass through costs in terms of when the associated events occurred, Figure 7 reports when NSPs will recover these costs from consumers. For some pass throughs, NSPs recover costs over several years after the event, which is why Figure 7 includes cost pass through revenue to be recovered up to 2026.
- Excludes AER's 2022-23 contribution determination of around $130 million to be paid by NSW DNSPs to the NSW Electricity Infrastructure Fund established under the (NSW) Electricity Infrastructure Investment Act.[32]

Figure 7 Revenue from cost pass throughs



Source: AER analysis of decisions under AER, *Cost pass throughs*, accessed 4 April 2023.

Note: Calculation to convert values to $ June 2022. Excludes the feed-in-tariff costs passed through to Queensland consumers in 2016 and 2017.

31 AER, *2022 Electricity network performance report*, July 2022, pp. 60-61

32 See AER, *NSW Electricity Infrastructure Fund 2023-23 contribution determination*, Effective 28 February 2023, accessed 7 June 2023.

Figure 7 illustrates that the AER received notably more cost pass through applications (14) in 2022 than in any previous year (the previous higher number was 7 in 2016).[33] While the amount recently approved for recovery is low relative to previous feed-in-tariff pass throughs,[34] the current high quantity of applications is already starting to have a cumulative impact on forecast revenues over the affected NSPs respective regulatory periods. This impact will be more noteworthy when we include applications submitted in 2023.

3.2 Network expenditure

Under the regulatory regime, we regulate revenue not expenditure. As such, NSPs can generally spend the revenue they collect from consumers however they determine to be most efficient in providing a safe and reliable supply of electricity.

In aggregate:

- NSPs spent less in 2022 than in 2021. NSPs also underspent against their forecasts by a greater extent (expenditure was about 15% lower than forecast in 2022 compared to being 2% lower in 2021).
- NSPs have been underspending against opex forecasts since 2018.

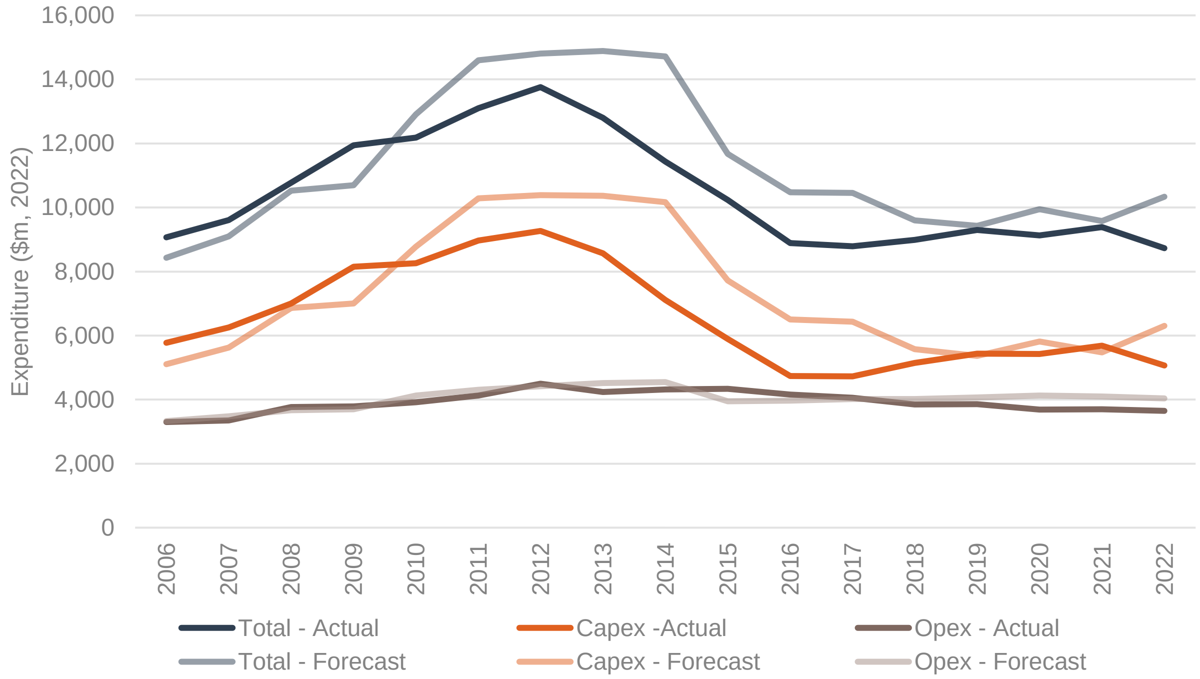
We apply revenue caps to electricity NSPs, which incentivises them to seek efficiency gains to spend less than forecast. The NSPs revealed costs inform future expenditure forecasts, so underspending contributes to lower expenditure allowances in future regulatory periods, reducing network charges faced by consumers. The trends in Figure 8 reflect with what we expect from this arrangement. For instance, NSPs have on average spent less capex than forecast since 2010, with capex forecasts then lowering substantially over 2015 to 2018.

The drivers of higher capex forecasts in 2022 differ as this mainly reflects the need for several large transmission investments to support the changing generation mix.

33 Cost pass through applications received in 2022 were comprised of natural disasters (3), network support costs (4), and insurance costs (2) and other costs (5).

34 $440 million and $384 million ($real 2022) of feed-in-tariff costs passed through to Queensland consumers in 2016 and 2017.

Figure 8 Total Expenditure - NSPs



Source: (a) Actual capex: RFM input - actual capex, actual asset disposal, actual capital contributions. Where RFM not available (i) for TNSPs, use CA: 2.1 Expenditure Summary, (ii) for DNSPs, use annual RINs: 8.2.4 Capex by asset class, 8.2.5 Capital contributions by asset class, 8.2.6 Disposals by asset class. (b) Actual opex: EB RIN - Table 3.2.2 Opex. (c) Forecast capex: PTRM Input - Forecast net capex. (d) Forecast opex: PTRM Input - Forecast operating and maintenance expenditure.

Notes: AER calculation to convert values into $ June 2022. Net capex is gross capex less capital contributions and disposals.

Some specific NSPs' expenditure outcomes materially affect these overall results, including:

- The forecast capex needs for Transgrid and ElectraNet increased in 2022 relative to 2021 by $693 million (107%) and $228 million (101%) respectively. These increases were largely due to higher allowed capex for works associated with Project EnergyConnect, which were approximately:[35]
  - $950 million in 2022 for Transgrid – compared to $232 million in 2021.[36]
  - $187 million in 2022 for ElectraNet – compared to $33 million in 2021.[37]
- Actual capex for Transgrid and ElectraNet in 2022 were lower than forecast by $856 million (64%) and $77 million (17%). A reprofiling of expenditure on Project EnergyConnect contributed to a large proportion of this underspend.
- Ausgrid spent less than its forecast opex by $142 million (29%). Ausgrid identified several drivers of opex outperformance, including cost reduction initiatives, a vegetation

35 We have reported Transgrid's forecast capex consistent with our 18 May 2018 determination. This excludes updates for the Humelink contingent project determination. In response to this update, the recent Transgrid determination (of 28 April 2023) for the costs of early works associated with the staged delivery of Humelink also increased Transgrid's forecast capex. Our final decision on the Humelink contingent project increased Transgrid's forecast gross capex from $1342.5m to $1390.8m in 2021-22 ($real 2022). For further information regarding the Humelink contingent project please refer to: *https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/contingent-projects/transgrid-humelink-contingent-project*.

36 Figures adjusted from $2018 to $2022 as found in AER, *Final decision - TransGrid contingent project - Project EnergyConnect*, 2021, Table 3.

37 Figures adjusted from $2018 to $2022 as found in AER, *Final decision – ElectraNet contingent project - Project EnergyConnect*, 2021, Table 3.

management transformation initiative, and savings in property management after selling several properties.[38] Ausgrid also spent less than its forecast net capex by $337 million (65%), which is net of asset disposals and capital contributions. This was largely driven by Ausgrid having higher than forecast asset disposals – Ausgrid did not have large gross capex underspends.

- Ergon Energy offsetting some of the magnitude of underspending by spending $281 million (58%) more capex than forecast for 2022, after having already spent $262 million and $196 million more than forecast in 2021 and 2020 respectively. This differs from most other DNSPs, which (except for Energex) underspent against their capex allowances in 2022. Ergon Energy submitted that most of this overspend was due to the 'need to address priority network safety and defect rectification programs', including defect rectifications and remediation works'[39].

It is also worth noting that in our last 2 reports we made observations about Power and Water's expenditure patterns. Specifically, we observed that Power and Water had incurred materially less capex and more opex than forecast since we commenced regulating them in 2020. In 2022, we observe that Power and Water underspent its opex allowance for the first time (7.6%) and underspent its capex allowance (18%) by less than it had in 2021 or 2020. As such, it is not clear that there is a specific pattern to monitor or understand at this current time.

3.3 Regulatory asset bases

RABs capture the total economic value of network assets that NSPs use to provide regulated network services. Over time, the RAB tends to grow as NSPs replace aging assets and expand their networks to service new customers. RAB values substantially affect NSPs' revenue requirements, and the total costs consumers ultimately pay. This is because consumers pay the costs of raising capital through the return on capital (calculated by applying the allowed rate of return to the RAB) and return of capital (loss of economic value as assets depreciate over the useful life) allowances. We also inflate the RAB each year to reflect the impacts of inflation. This increases the nominal value of the assets to maintain their real value through time.[40]

Network assets in the RAB have been accumulated over time and are at various stages of their economic lives. Some NSPs' average asset lives may be relatively old or young depending on their growth and their phase of the replacement cycle.

38 Ausgrid, *2021-22 Annual RIN Response – Consolidated,* 31 October 2022, Table 8.4.3.

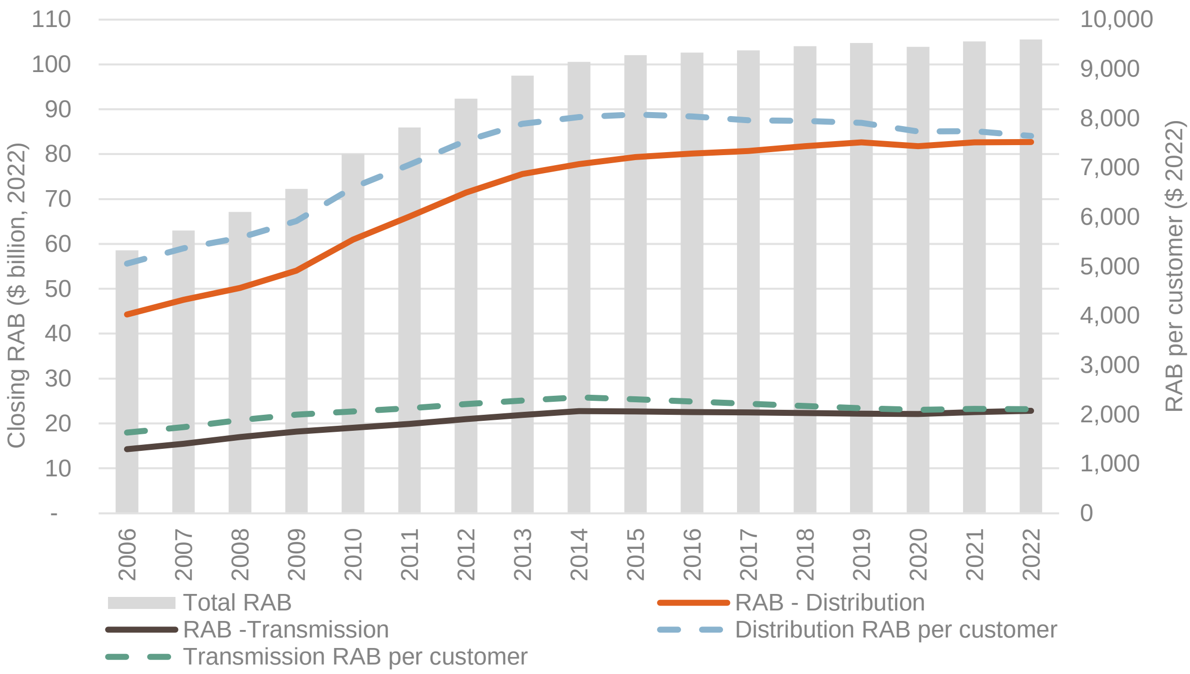
39 Ergon Energy, *2021-22 Annual RIN response – Consolidated*, 31 October 2022, Table 8.2.2.

40 The indexation of the RAB is explained on our website here.

3.3.1 Total RAB growth

- In 2022, the total real value of RABs increased on 2021 by 0.36%. We expect RAB growth rates to increase in the future, due to the greater investment into large network projects required to enable the reliable supply of low carbon energy.[41]
- RAB growth in 2022 is the combination of:
  - 0.1% growth in distribution network RABs
  - 1.2% growth in transmission network RABs, which until 2021 had been declining since 2014. We expect growth in transmission network RABs to continue as several major transmission projects are under development.
- Since 2014, RAB growth has been modest following material reductions in actual capex. In contrast, growth rates over the 2006-2014 period averaged around 7% per annum.

Figure 9 Total and per customer RABs



Source: (a) Closing RAB: RFM, 'RAB roll-forward'. (b) Customers: Economic Benchmarking RIN table 3.4.2, 'Distribution customer numbers by customer type or class'.

Note: AER calculation to convert RABs into $ June 2022 values and to calculate RAB per customer as (a) divided by (b).

41 For background into the range of large network investments required to maximise net economic benefits given the current energy transition, see AEMO, [2022 Integrated System Plan (ISP)](), accessed 7 June 2023.

Growing RABs do not necessarily result in growing capital costs per customer if either the rate of return is declining, or the customer base is growing. From 2015 to 2020, customer numbers grew faster than real RABs, resulting in a levelling and occasionally declining average RAB per customer. In 2022, network RABs per customer decreased by 1%.

3.4 Network reliability

A key network service output is to provide a reasonably reliable supply of electricity. In this context, reliability refers to the continuity of electricity supply and is typically measured by the frequency and duration of interruptions to supply. ‘Reasonably’ recognises there is a trade-off between reliability and affordability as maintaining or improving reliability may require expensive investment in network assets. Reliability standards and incentive schemes therefore target reliability levels for which most customers are willing to pay.

We collect and report data on reliability for both DNSPs and TNSPs, however, we have focussed our analysis on DNSPs as most supply interruptions originate at the distribution level. We publish TNSP reliability measures alongside this report in our operational performance data model. Our model also includes data disaggregated by each NSP, which can be informative, particularly as average outage duration can vary considerably between NSPs.

3.4.1 Outages to supply

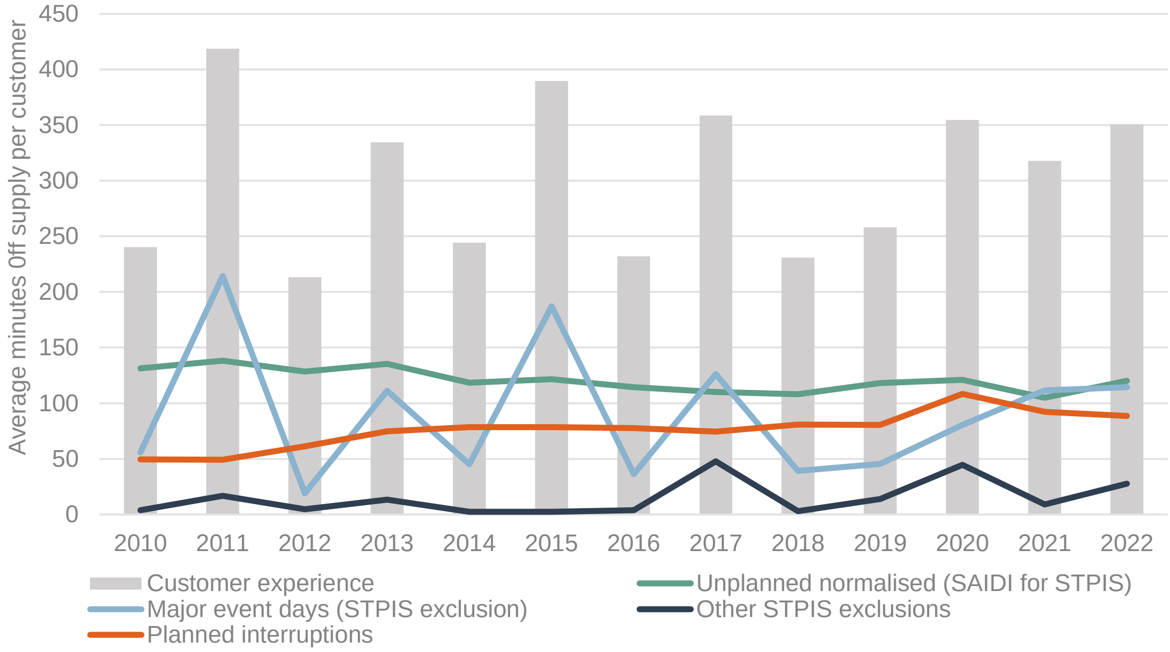
We limit this section of our report to outages that impacted customers in the National Electricity Market (NEM), that is, excluding Power and Water. Outage measures are broken down by:

- The frequency and duration of unplanned outages, which we determine under our STPIS to be within the NSP’s control given their respective funding levels. This excludes some outages, including major events that are part of the total unplanned outages. We refer to these as 'normalised' measures of reliability:
  - System Average Interruption Frequency Index (SAIFI) measures the average number of interruptions each year outside of excluded events.
  - System Average Interruption Duration Index (SAIDI) measures the average duration (minutes) of interruptions each year outside of excluded events.
- Unplanned outages excluded from SAIDI and SAIFI. These include outages that occurred on major event days as well as other defined excluded events (for example, outages due to transmission-level faults).
- Planned interruptions.

- The duration of unplanned normalised distribution outages per customer (measured by SAIDI) increased slightly in 2022. Despite observed annual variability, the longer term trend indicates the duration of unplanned (normalised) outages is declining.
- While the average frequency of unplanned normalised outages per customer (measured by SAIFI) increased by 4% in 2022, SAIFI has decreased by 2.9% per annum since

2010. For instance, there was around one normalised outage per customer in 2022, which is notably lower than the 1.4 normalised outages per customer recorded in 2010.

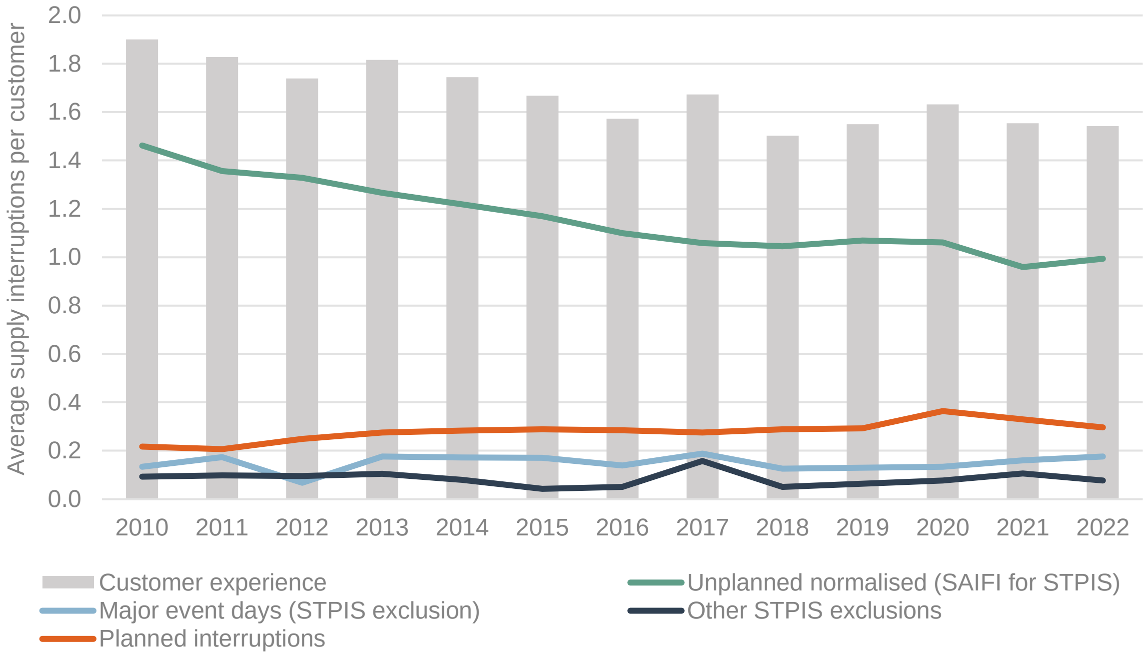
Figure 10 Duration of distribution outages – Whole of NEM



Source: Category Analysis RINs, AER analysis.

Notes: Data reflects interruptions to supply that lasted longer than 3 minutes consistent with the definition of a sustained interruption in STPIS version 2.0 (November 2018). This differs from the 1-minute threshold in STPIS version 1.0 (May 2009). Years reflect 1 July – 30 June.

Figure 11 Frequency of distribution outages – Whole of NEM



Source: Category analysis RINs, AER analysis.

Notes: Customer experience is the sum of the 4 categories of outages depicted in the line chart. Data reflects interruptions to supply that lasted longer than 3 minutes consistent with the definition of a sustained interruption in STPIS version 2.0 (November 2018). This differs from the 1-minute threshold in STPIS version 1.0 (May 2009). Years reflect 1 July – 30 June.

Over the longer time series, we observe that:

- Consumers have experienced fewer distribution network outages, which is evident in both SAIFI and when accounting for excluded unplanned outages.
- SAIDI shows a less consistent trend since 2011. There is also notable variability in excluded outages, which mainly consist of major event days. In some years, high impact supply interruptions have resulted in a material difference between normalised reliability and the duration of total unplanned outages.

Comparing the impact of excluded events on the frequency and duration of outages shows that we are excluding relatively few events, but these can have a substantial impact on the average duration of outages that consumers experience. This is consistent with the impact of major events, such as the Queensland floods (February-March 2022), the South Australian black system event (September 2016), and the summer 2019/20 bushfires affecting Victoria and NSW.

3.4.2 Average outage duration

Since 2021, we reported on the average duration of normalised customer interruptions, calculated as SAIDI over SAIFI. We observed a long-term increase in the average normalised outage duration and questioned whether DNSPs had stronger incentives to improve SAIFI at the expense of SAIDI.[42] After observing a reduction in the average normalised outage duration between 2020 and 2021, we considered this could have been connected to the re-weighting of incentives under the STPIS.[43] However, we concluded more data would be needed before we could draw such a conclusion. We also identified that interpretation would be difficult given the re-weighting coincided with a threshold change for what outages could be captured as sustained interruptions.[44]

While we will continue to monitor the relationship between frequency and duration of outages, we will no longer regularly report on this measure unless we identify a noteworthy result. Interpreting average outage duration is difficult as it is generally unclear if movements in this measure are positive or negative. While we set STPIS targets for measuring performance in terms of outage duration and frequency, we do not have a particular view on what would constitute a benchmark average outage duration. For completeness, we have observed that the average outage duration increased in 2020, reduced in 2021 and increased in 2022.

42 AER, *Electricity network performance report 2022*, July 2022, p. 18; AER, *Electricity network performance report 2021*, September 2021, p. 20.

43 STPIS incentive weights were updated from equal weights to 40:60 for SAIFI and SAIDI to reduce the apparent incentive for NSPs to improve SAIFI over SAIDI. These updates applied in NSW, ACT and Tasmania from 2020; Queensland and South Australia from 2021; and Victoria from 2022. See AER, *Explanatory statement: Final decision— Amendment to the Service Target Performance Incentive Scheme (STPIS); Establishing a new Distribution Reliability Measures Guideline (DRMG)*, November 2018.

44 We established the new threshold for a sustained interruption from at least one minute to at least 3 minutes in AER, *Electricity DNSPs: STPIS version 2.0*, November 2018, p. 25, which has been gradually taking effect as STPIS 2.0 is applied to new regulatory control periods – the NSW, ACT and NT DNSPs since the 2020 regulatory year end, and the SA and QLD DNSPs since the 2021 regulatory year end.

3.4.3 Reliability across feeder types

In 2022, we discussed how consumers on different feeder types experience different levels of reliability.[45] We have updated our analysis from 2022 and intend to illustrate feeder-type performance on an individual DNSP basis when we release our networks data dashboard in late 2023.

In future years, we intend to only present this data in dashboard form for individual DNSPs. While Figure 12 is informative of the differences in reliability experienced on different feeder types, these aggregated measures also need to be interpreted cautiously as DNSPs do not always apply definitions consistently when classifying feeders.

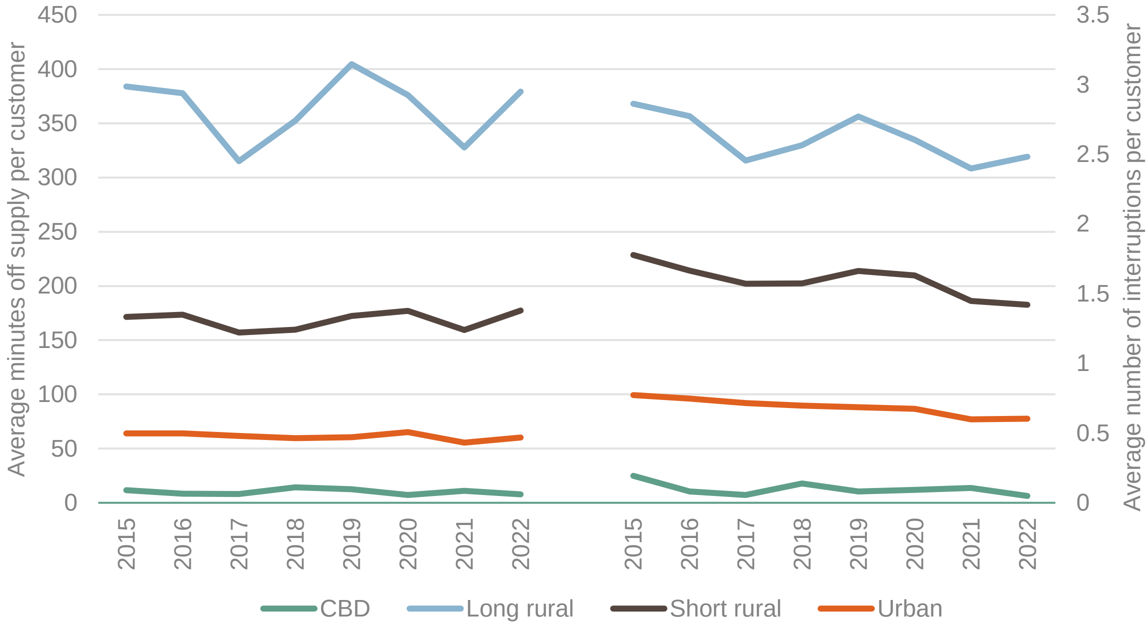
What are the feeder types?

Customers are divided into 4 feeder types.

- CBD – a feeder in one or more geographic areas that the relevant participating jurisdiction has determined as supplying electricity to predominantly commercial, high-rise buildings. These feeders are supplied by a predominantly underground distribution network containing significant interconnection and redundancy when compared to urban areas.
- Urban – a feeder that is not a CBD feeder and has a maximum demand over the feeder route length greater than 0.3 MVA/km.
- Rural short – a feeder with a total feeder route length less than 200km that is not a CBD or urban feeder.
- Rural long – a feeder with a total feeder route length greater than 200km that is not a CBD or urban feeder.

45 AER, *2022 Electricity network performance report*, July 2022, pp. 19-20.

Figure 12 Normalised reliability by feeder type – DNSPs*



Source: Annual RIN - 6.2.1 Unplanned minutes off supply (SAIDI) - total sustained minutes off supply after removing excluded evets, Annual RIN - 6.2.2 - Unplanned interruptions to supply (SAIFI) - total sustained interruptions after removing excluding events, EB RIN - 3.4.2 Customer numbers.

Note: AER calculation to weight results by DNSP customers on each feeder type.

* We have excluded data for TasNetworks as different feeder classification categories are used in Tasmania.

Figure 12 shows that on average, normalised interruptions on rural feeders are longer and more frequent than on CBD or urban feeders. This is driven by several factors such as network topology, increased response time relative to line length and the lower likelihood of having in-built redundancy on longer feeders.

3.5 Network safety

Safety forms part of the national electricity objective (NEO), which is to achieve the long-term interests of electricity consumers with respect to several outcomes, including the safety of electricity supply and national electricity system. We are currently consulting on collecting data on major and other safety incidents through a regulatory information order. We intend to include our analysis of this data in future reports as a high-level indicator of how safety outcomes move over time.

In the meantime, we have continued to summarise what safety reporting and data is available as an information resource for stakeholders. Table 3-1 summarises the sources of publicly available safety data, which are available at the jurisdictional level. Jurisdictional regulators monitor and audit NSP compliance with safety obligations as set out in the relevant legislation, licence conditions and standards. This includes monitoring whether NSPs’ Electricity Network Safety Management Systems (ENSMS) are developed to a minimum standard, including in identifying and evaluating risk control measures and treatments.

Table 3-1 Sources of publicly available network safety data

Jurisdiction	Published reports
NSW	NSPs publish annual reports of ENSMS data on their websites.[46] The Independent Pricing and Regulatory Tribunal (IPART) also publishes annual reports detailing compliance outcomes, events and treatments.[47]
ACT	The Utilities Technical Regulator (UTR) publishes annual reports on its website that detail compliance outcomes, events and treatments.[48] Reports cover Evoenergy and TransGrid.
VIC	Energy Safe Victoria (ESV) publishes annual reports detailing compliance outcomes, events, and treatments.[49] Each DNSP also submits fire-start reports to the AER under the F-factor scheme.[50]
QLD	Annual reports from Powerlink and Energy Queensland (including data on Ergon Energy and Energex).[51] Queensland's Electrical Safety Office does not publish their annual compliance reports.
SA	SA Power Networks and ElectraNet report results of audits against their Safety, Reliability, Maintenance and Technical Management Plans to the Office of the Technical Regulator (OTR). The OTR then publishes technical regulator annual reports detailing key performance indicators and compliance outcomes, events and treatments.[52]
TAS	TasNetworks (distribution and transmission) publishes annual reports, which include information on significant incidents, reportable incidents and total recordable injury frequency rates.[53] The Office of the Tasmanian Regulator's annual performance reports do not cover safety performance.
NT	Power and Water publishes annual reports, which include lost time injury frequency rates.[54] The Electricity Safety Regulator (within NT WorkSafe) publishes annual reports, although its remit excludes electrical infrastructure owned and operated by electricity entities.[55]

Source: AER analysis.

We encourage readers to refer our 2022 electricity network performance report for a comprehensive list of the safety indicators published in specific jurisdictions at the time. These indicators fall under the following categories:[56]

46 Ausgrid, *Annual ENSMS performance report*, 2022; Endeavour Energy, *Annual ENSMS performance report*, 2022; Essential Energy, *ENSMS performance & bushfire preparedness report*, October 2022; Transgrid, *Annual safety performance and bushfire preparedness report*, 2022.

47 IPART, *Annual compliance report - Energy network operator compliance during 2021-22*, October 2022.

48 Access Canberra, *Utilities Technical Regulation: Related resources*, accessed 7 June 2023.

49 Energy Safe Victoria, *Safety performance report on Victorian electricity networks*, October 2022.

50 We released fire start reports for 2021-22 in June 2022 for AusNet Services (D), CitiPower, Jemena Electricity, Powercor and United Energy. The F-factor scheme does not apply to AusNet Services (T).

51 Energy Queensland, *Annual report 2021-22*, 2022; Powerlink, *Annual report and financial statements 2021/22*, 2022.

52 Department of Energy and Mining, *Annual report of the technical regulator*, 2022.

53 TasNetworks (distribution and transmission), *Publications: Annual reports*, accessed 7 June 2023.

54 Power and Water, *Corporate reports: annual reports*, accessed 7 June 2023.

55 Department of the Attorney-General and Justice – Electricity Safety Regulator, *Annual report 2021–2022*, 2022.

56 AER, *2022 Electricity network performance report*, July 2022, pp. 67-69.

- Leading safety indicators: Proactive maintenance and inspection, vegetation management, emergency preparedness
- Potentially leading or lagging safety indicators: Asset failures, near misses
- Lagging safety indicators: Shocks and switching incidents/arc flashes, fire incidents, workplace injuries, damage to property or environment, public network contact incidents

3.6 Distribution network utilisation

Network utilisation measures the extent to which a DNSP's network assets are being used to meet maximum demand. We measure network utilisation as the ratio of reported non-coincident maximum demand (MVA) to total zone substation transformer capacity (MVA). Non-coincident maximum demand across the network adds up load at geographic points (connection points or some other spatial level) when each geographic point experienced maximum demand. This differs from network coincident maximum demand, which measures demand across whole network when it was at its highest.

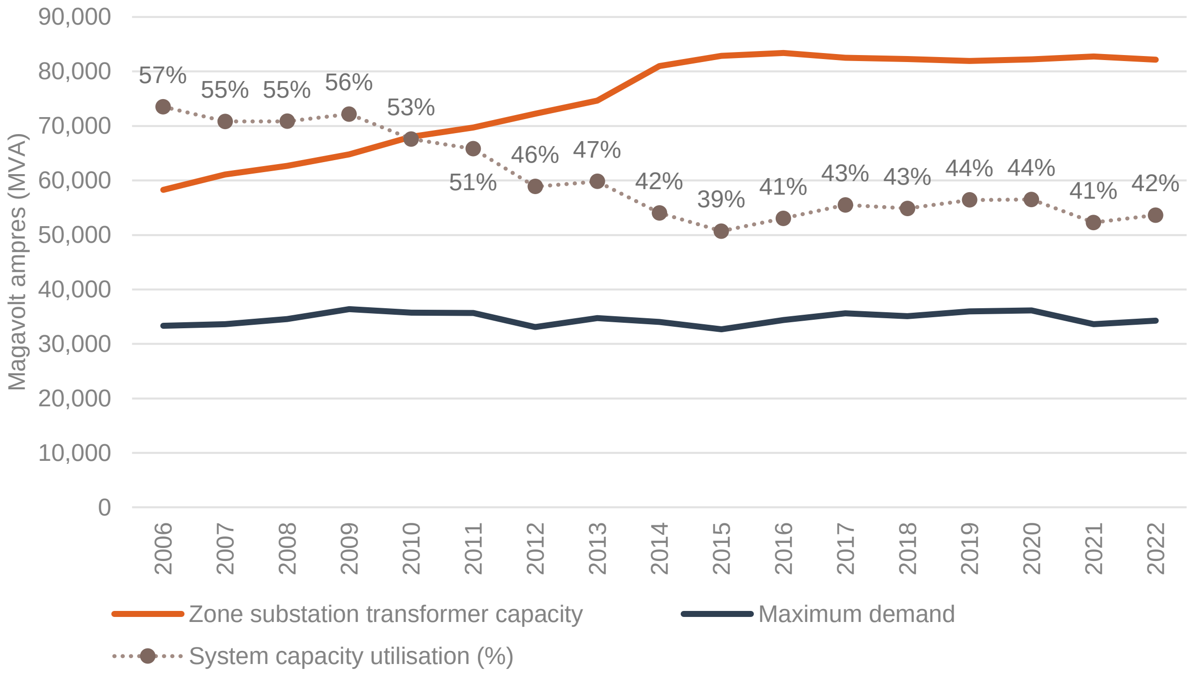
Utilisation is an informative but incomplete measure of the network assets' preparedness to respond to short term changes in demand given that low utilisation (or high spare capacity or redundancy) means the network can service large increases in demand. Some spare capacity is important to maintain the service outputs consumers expect and is also influenced by the 'lumpy' nature of investment in long-lived network assets.

However, lower utilisation in combination with relatively stable load profiles can mean consumers are paying for network assets they rarely use. If utilisation is inefficiently low, consumers will be paying more for excess capacity than the value of the benefits they gain from it. Prudent network investment is therefore important for managing network utilisation. Prudent investments maximise net economic benefits when considering all feasible options to meet that need (including non-network options, smaller and more scalable options, and deferral options). Managing variations in consumer demand by using more efficient price signals and other demand management solutions is another way to improve network utilisation.

While informative, it is worth recognising the data used to develop Figure 13 provides an aggregated network-wide measure of utilisation, which masks localised issues.

- Average distribution network utilisation increased from 41% in 2021 to 42% in 2022. Annual movements in network utilisation are mainly driven by changes in maximum demand; with zone substation transformer capacity showing little variation since 2015.
- Network utilisation reached a low of 39% in 2015 after a period of large network investment.

Figure 13 Total distribution network utilisation

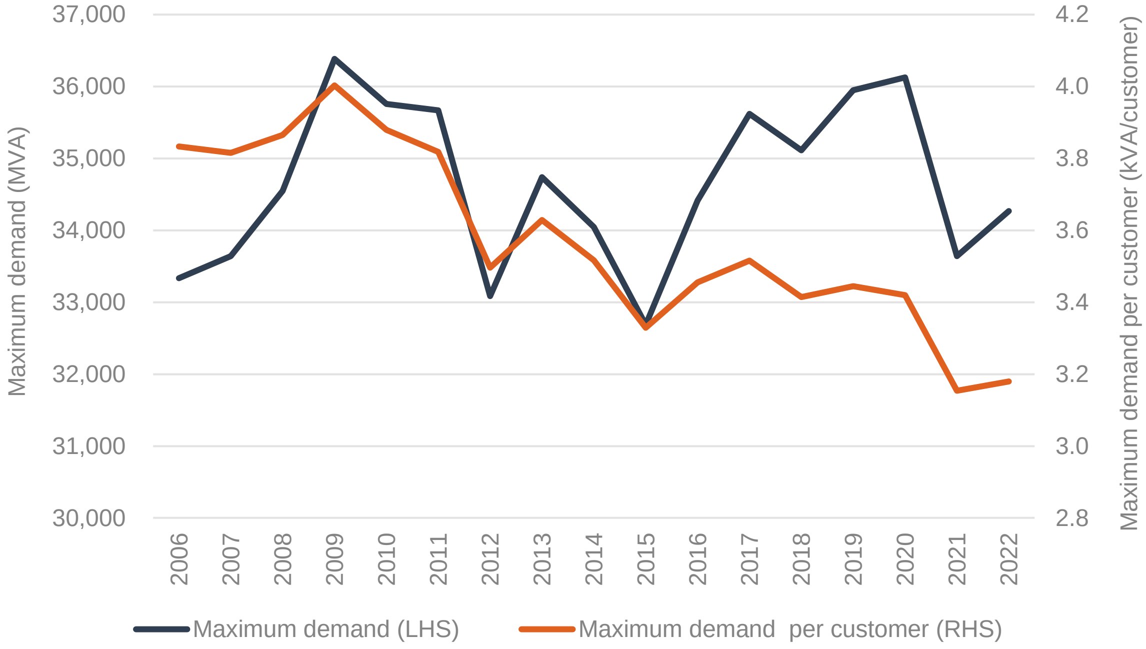


Source: (a) Non-coincident summated raw system annual maximum demand from EB RIN table 3.4.3.3 – Annual system maximum demand characteristics as the zone substation level – MVA measure. (b) Zone substation transformer capacity from EB RIN table 3.5.2.2.

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

Figure 14 shows that maximum demand per customer has been trending downwards overall, with annual variation. Improvements in energy efficiency and increasing penetration of consumer energy resources would dampen maximum daytime demand over time, with drivers such as weather effects influencing some of the annual variation.

Figure 14 Maximum demand and maximum demand per customer



Source: (a) Summated raw system annual maximum demand from EB RIN table 3.4.3.3 – Annual system maximum demand characteristics as the zone substation level – MVA measure, (b) EB RIN table 3.4.2 – Distribution customer numbers by customer type of class.

Notes: Maximum demand per customer in KVAs is an AER calculation of 1000 × (a) ÷ (b).

In future years' reporting, we may expand on this analysis to investigate the changing dynamics of maximum demand per customer. This analysis could provide useful insights into the effects of energy efficiency, demand management and consumer energy resources on maximum demand per customer. This analysis could also help us to better understand the extent that electrification and greater use of electric vehicles could impact the current downwards trend.

3.7 Progress of tariff reform and enabling technology

Last year, we reported on tariff reform (proportion of cost reflective tariffs) and enabling technology (smart meter penetration rates) as part of a focus area. This year, we are including this information as a core measure given its continued importance while tariff reform and enabling technology are still being rolled out.

3.7.1 Enabling technology – Smart meters

Coordinating and installing smart meters outside of Victoria is not the responsibility of DNSPs. As such, smart meter penetration does not reflect network performance. However, smart meter penetration provides important contextual information as this technology is required for DNSPs to assign customers to cost reflective network tariffs. Given the importance of smart meters, the AEMC has been undertaking a review into options for accelerating their deployment in the NEM.[57]

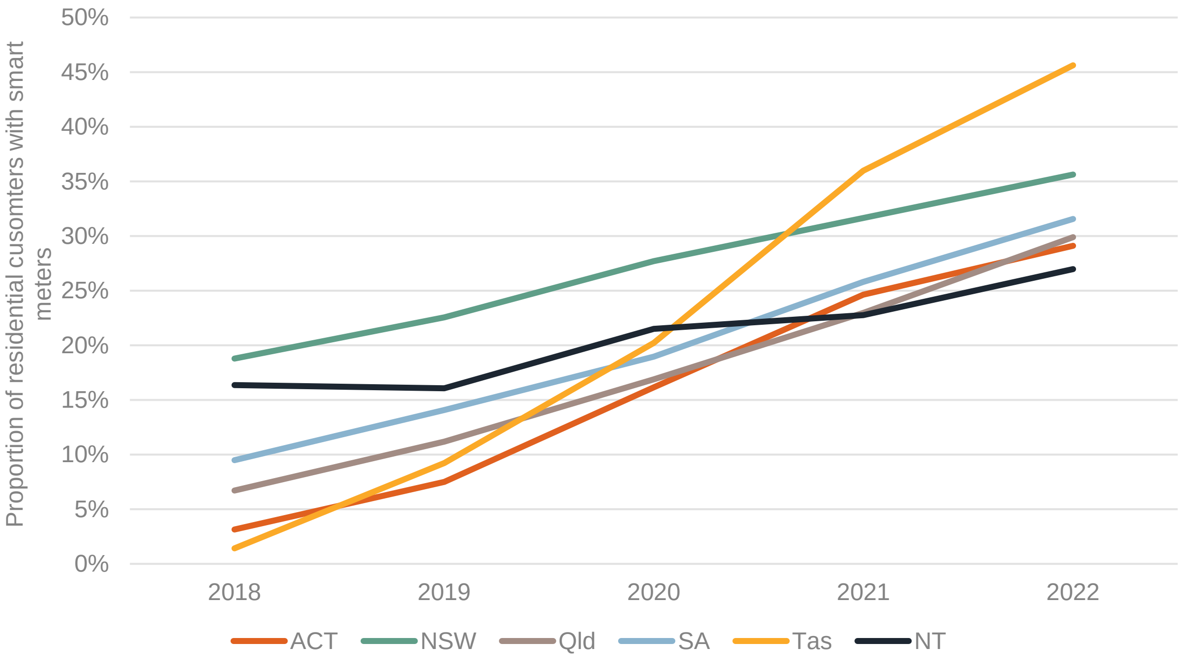
[57] AEMC, Review of the regulatory framework for metering services, accessed 7 June 2023.

We report 'smart meters' as the sum of Type 4 and Type 5 meters.[58] These do not include accumulation meters, which are still the predominant type of meter used outside Victoria. Accumulation meters measure how much energy is consumed over a period, but not the time of day. Smart meter installations are currently triggered by upgrades from single to 3 phase connections, solar PV installations, replacements of old accumulation meters and new connections. Type 5 meters are more limited than type 4 meters only allowing time of use pricing.

The rate of smart meter deployment for different customer types varies across jurisdictions as shown in Figure 15 and Figure 16. The proportion of customers on smart meters also varies between individual DNSPs, with this information also provided in our operational performance data published alongside this report.

We have excluded smart meter deployment rates in Victoria in Figure 15 and Figure 16. This is because smart meters have been nearly ubiquitous in Victoria since the DNSP-led roll out was nearly complete at the end of 2015.[59]

Figure 15 Proportion of residential customers outside of Victoria with a smart meter

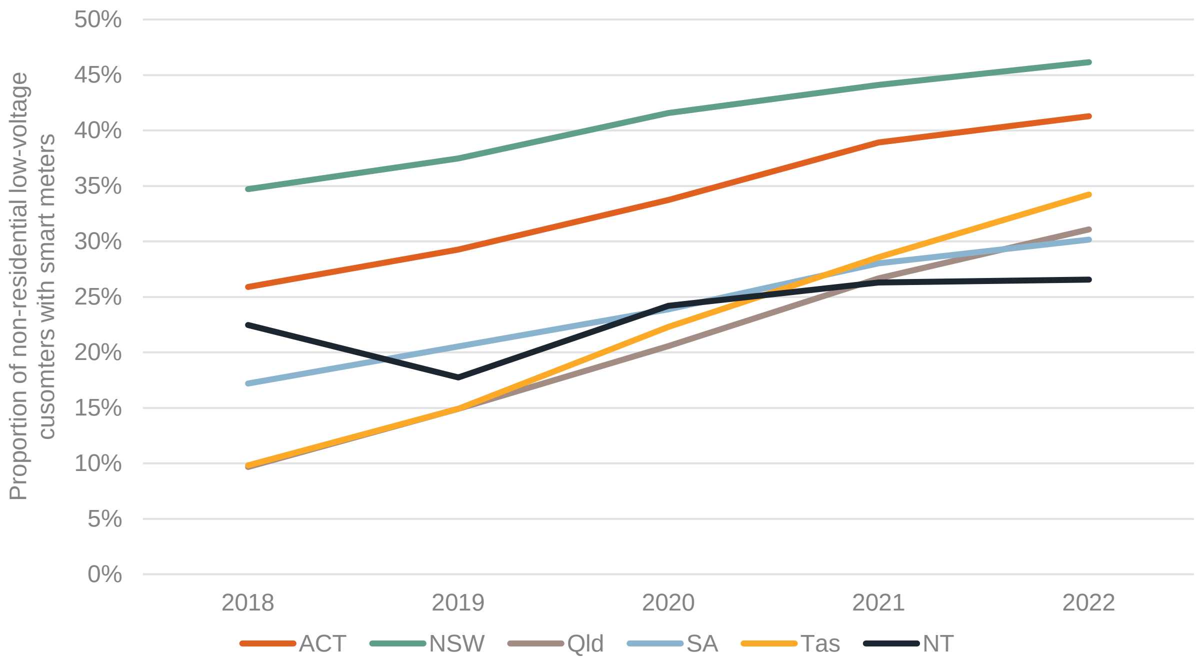


Source: Annual RIN P1.1, 'Distribution customers numbers by meter type'. This reflects the reported number of customers with a type 4 or type 5 meter.

58 While Type 1-3 meters are also smart meters, these are only available to large customers. We do not report on large non-residential customers in this section as they have full smart meter penetration.

59 In 2022, 99.5% and 97.3% of residential and non-residential low-voltage customers in Victoria had smart meters, respectively. Also see AER, *Final decision - AMI transition charges applications*, 2016, p. 4.

Figure 16 Proportion of non-residential low-voltage customers outside of Victoria with a smart meter



Source: Annual RIN P1.1, 'Distribution customers numbers by meter type'.

Figure 15 and Figure 16 show that in the ACT and NSW non-residential low-voltage customers generally have a higher proportion of smart meters than residential customers.

3.7.2 Cost reflective pricing

Cost reflective network pricing aims to provide network customers with financial incentives to use the network more when there is spare capacity rather than when increased use would cause constraints that can be costly to rectify. This may entail charging consumers more in peak periods when load is high and consumers are less able to draw on their energy resources, like solar PV (thereby avoiding thermal constraints). It may also entail charging consumers less (potentially even negative amounts) to use the network more when demand is low, and energy generated by solar PV is high (thereby avoiding voltage constraints). By avoiding costs required to rectify network constraints, NSPs can run the network at a lower cost, thereby lowering costs faced by consumers.

Since the first round of tariff structure statements in 2017, DNSPs have been required to gradually make their tariffs better reflect the costs of serving their customers to realise the benefits discussed above.[60] Given that cost reflective pricing should encourage more efficient use of the network, we expect this should result in lower revenue per customer.

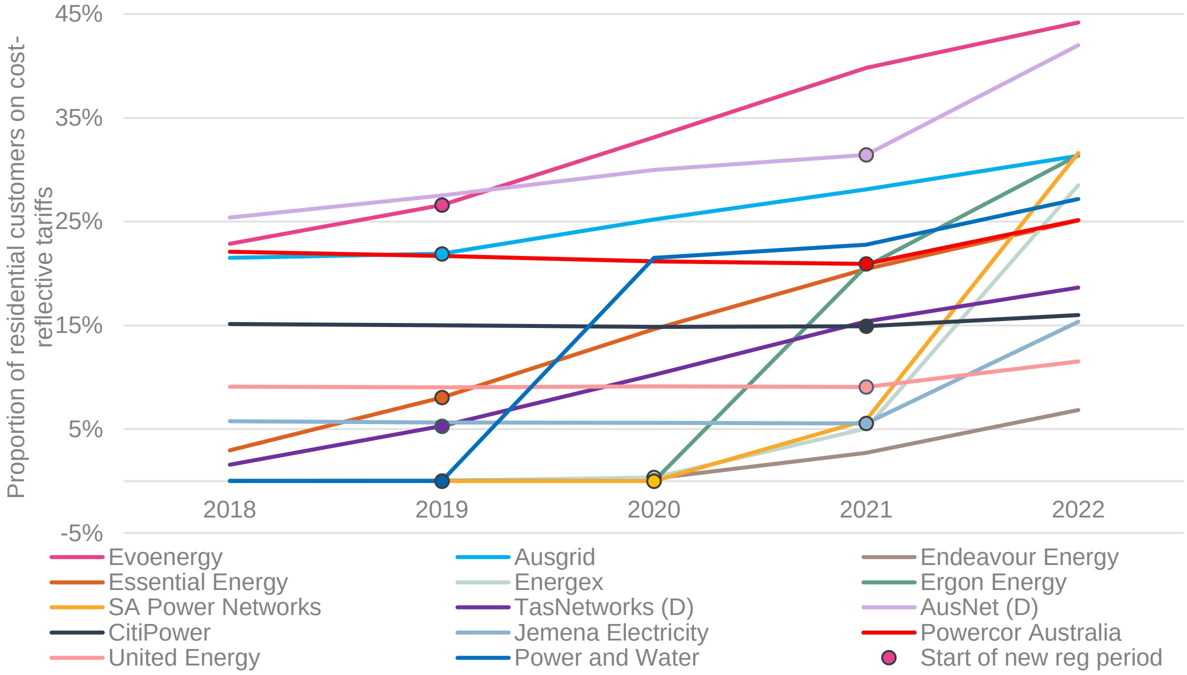
Once an end-use customer is assigned to a particular tariff, the DNSP will pass the relevant charges onto its direct customers, which are generally retailers. An important nuance of cost

60 As per the pricing principles in clause 6.18.5 of the NER.

reflective network pricing is that retailers can then choose to pass the relevant network tariffs though to their customers but may choose to package these costs up in a different way.

Figure 17 and Figure 18 show the proportion of residential and non-residential low-voltage customers on cost reflective tariffs. These figures also identify when new regulatory periods commenced, which is when new tariff structure statements come into effect. Given tariff structure statements are the mechanism under which DNSPs gradually make their tariffs more cost reflective, we would expect to see an uptick in the proportion of cost reflective tariffs after those points. This is what we observe. For instance, there has been a visible increase in the proportion of cost reflective tariffs in Victoria since 2021, which marked a new regulatory period for the Victorian DNSPs; AusNet Services, Jemena, CitiPower, Powercor and United Energy.

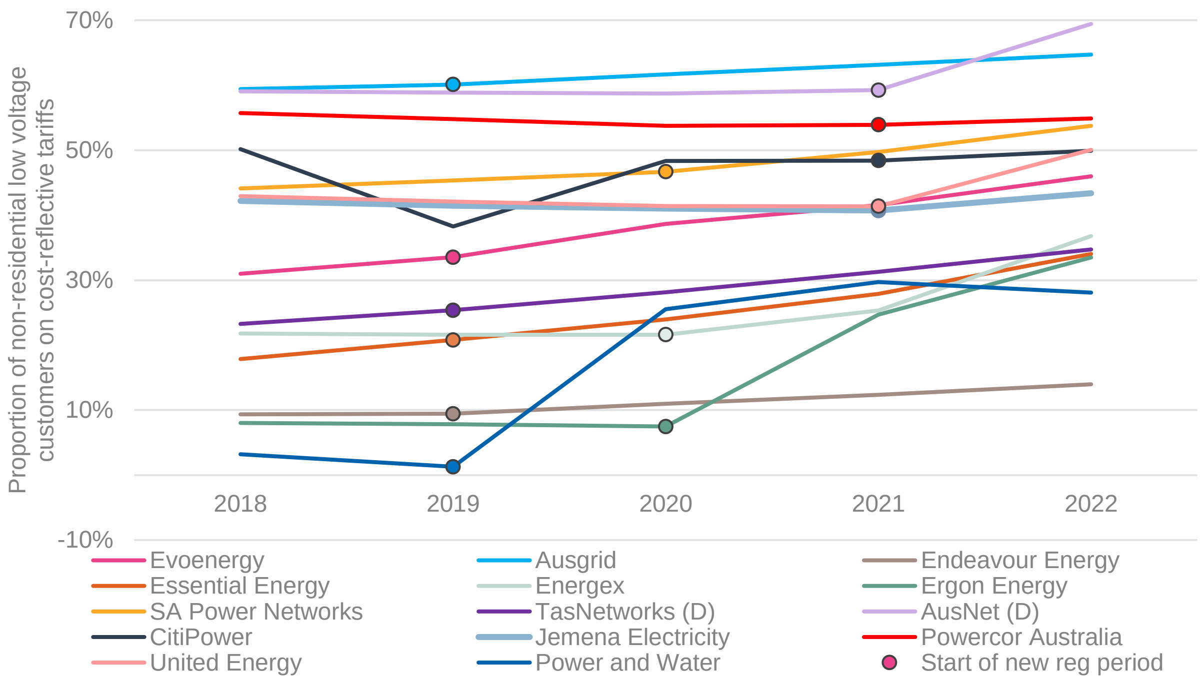
Figure 17 Proportion of residential customers on cost reflective tariffs



Source: Annual RIN P1.3(a) – NMI count – By tariff type – Residential.

Notes: AER calculation of P1.3(a)(1)) divided by the sum of P1.3(a)(1) and P1.3(a)(2).

Figure 18 Proportion of non-residential low-voltage customers on cost reflective tariffs



Source: Annual RIN P1.3(b) – NMI count – By tariff type – Non-residential – Low voltage.

Notes: AER calculation of P1.3(b)(1) divided by the sum of P1.3(b)(1) and P1.3(b)(2).

Our key observations from Figure 17 and Figure 18 are that:

- The proportion of customers on cost reflective tariffs is generally increasing. This is expected as DNSPs have been required to gradually transition more customers to cost reflective tariffs since 2017.[61] Moreover, while we approved opt-in approaches to end-use customer assignment at the start of this transition period (that is, in the first round of tariff structure statements), we have since been supporting mandatory or default assignment with the option to opt-out for customers with smart meter technologies installed. With new tariff structure statements coming into effect each new regulatory period, we are generally seeing a higher proportion of end-use customers facing cost reflective tariffs.
- The proportion of customers with smart meters on cost reflective tariffs is relatively low in Victoria. Even among DNSPs with lower smart meter penetration rates, Victorian DNSPs have a low proportion of residential customers on cost reflective tariffs (with Ausnet Services being the exception)—although Victorian DNSPs generally have higher than average proportions of non-residential customers on cost reflective tariffs. The small proportion of Victorian end-use customers with smart meters on cost reflective tariffs may be due to the rollout being practically completed at the end of 2015,[62] before the tariff structure statements commenced. Under the initial round tariff structure statements, existing smart meter customers had to opt-in to a cost reflective tariff. These arrangements affected Victorian customers more. This was not only because Victoria had a greater proportion of existing smart meter customers, but due to the timing of regulatory periods, the second round of tariff structure statements took effect later in Victoria than in other jurisdictions.

61 AER, *Pricing proposals & tariffs*, accessed 7 June 2022.

62 AER, *Final decision - AMI transition charges applications*, 2016, p. 4.

4 Financial performance in 2022

This section looks at financial performance, or network profitability, as a core performance outcome. This entails considering indicators of profit that NSPs have been able to generate from the revenue allowances paid by consumers, including:

- returns on assets (section 4.1)
- earnings before interest and tax (EBIT) per customer (section 4.2)
- returns on regulated equity (section 4.3)

The regulatory framework is designed to compensate NSPs in expectation for efficiently incurred costs (such as opex, depreciation, interest on debt and tax) and to provide them with an expected profit margin in line with the required return in the market for an investment of similar risk. The expected profit margin, if set at an appropriate level and supported by appropriate incentives, should attract efficient investment.

As a feature of the incentive-based regulatory framework, we expect NSPs' actual outcomes to differ from the forecasts and benchmarks we set. The revenue requirement does not provide a guaranteed return, as NSPs' actual returns are determined by other factors, including but not limited to the following:

- Whether NSP expenditure differs from the revenue allowances we determine. Under the regulatory regime, NSPs can earn higher returns by seeking cost efficiencies, which consumers ultimately benefit from as these are accounted for in NSPs' expenditure allowances in subsequent regulatory periods.
- Returns NSPs achieve by departing from benchmarks in a way that does not affect costs to energy consumers. For example, NSPs can earn higher returns when they bear more risk by holding a higher proportion of debt than the benchmark of 60%.[63] NSPs can also earn higher returns if they operate under a flow-through tax structure where a tax rate of less than the assumed 30% tax rate applies.
- Additional revenue from performing well against incentive schemes. In our recent review, we found that our incentive schemes improved outcomes for consumers through incentivising: lower costs, higher reliability, and other desirable outcomes.[64]

Notwithstanding the above, to the extent that profitability results are systematically and materially higher or lower than forecasts or benchmarks, this would prompt us to investigate the causes in more detail.

63 NSPs will balance the lower costs they can achieve from having higher gearing against the negative impact that higher gearing can have on their credit ratings, and subsequent ability to raise debt at lower costs.

64 AER, *Review of incentives schemes for networks: Final decision*, April 2023, pp. 5-6.

Allowed returns on capital

The return on capital building block included in our revenue determinations is made up of a return on debt component and a return on equity component. The allowed return on debt, for example, is made up of the amount of debt we forecast (RAB × gearing; where gearing is based on a benchmark of the ratio of assets financed with debt rather than equity) multiplied by the allowed rate of return on debt. Equity is similar.

Rates of returns on debt and equity in combination can be referred to as the weighted average cost of capital or the allowed rate of return and are based on what the AER estimates a benchmark efficient entity would incur.

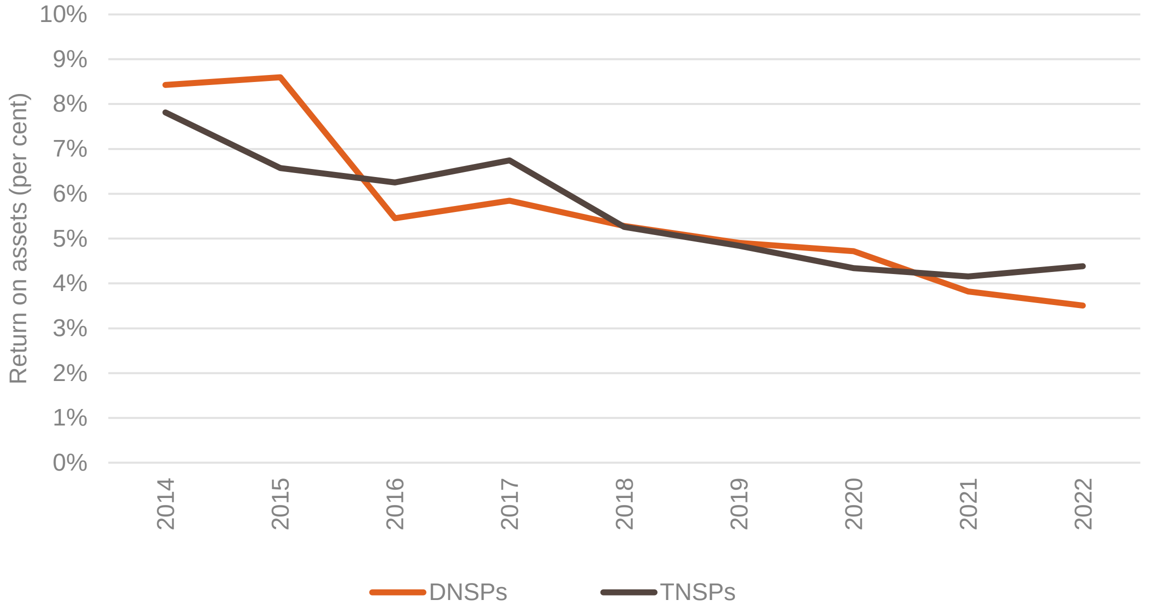
4.1 Returns on assets

The return on assets is measured as EBIT divided by RAB. It is a simple measure allowing us to compare NSP profits against our allowed rates of return. It captures the return that NSPs are able to earn from their regulated asset base as a whole.

In 2022, the average return on assets experienced by NSPs:

- decreased for DNSPs and increased for TNSPs.
- was 3.70%, compared to the allowed rate of return of 2.98%.

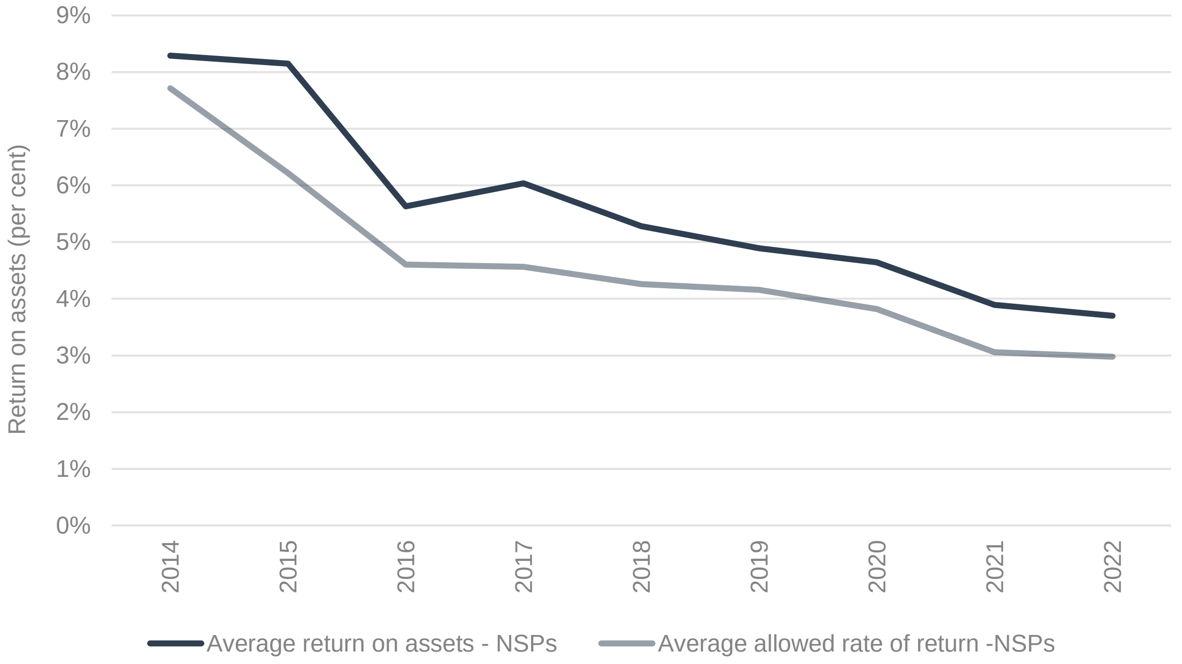
Figure 19 Weighted average real returns on assets - DNSPs and TNSPs



Source: Financial performance model.

Notes: Calculation details are in the financial performance model and return on assets explanatory note published alongside this report. Averages are weighted by the RAB of each NSP.

Figure 20 Real returns on assets compared to allowed real rate of return



Source: Return on assets - financial performance model, allowed real rate of return - PTRM ‘WACC’ sheet

Notes: Calculation details are in the financial performance model and return on assets explanatory note published alongside this report. Averages are weighted by the RAB of each NSP.

Figure 20 above shows NSPs have continued to generate real returns on assets which exceed forecast returns despite declining forecast returns.

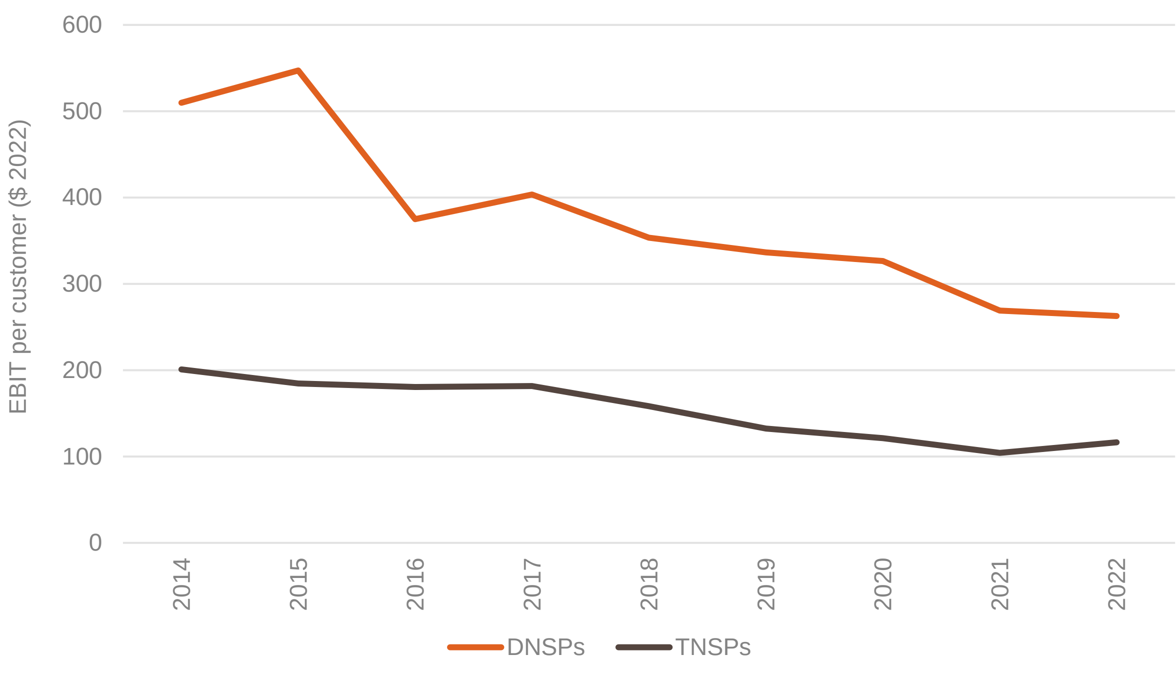
4.2 EBIT per customer

EBIT per customer is a measure of an NSP's operating profit divided by its customer base. It complements the return on assets by capturing the same measure of profit (EBIT) over a different cost-driver. EBIT per customer does *not* measure the profit that individual residential customers contribute to their NSP. It is an average of all customers, including businesses and large consumers who contribute substantially more network revenue per customer.

In 2022, EBIT per customer decreased slightly for DNSPs and increased slightly for TNSPs.

Figure 21 sets out the average real EBIT per customer, including incentive scheme payments and excluding the impacts of RAB indexation. In our view, this is the most informative single version of the EBIT per customer measure. It uses an estimate of EBIT that is consistent with how it is calculated in estimating real returns on assets.[65]

Figure 21 Average EBIT per customer - Including incentive scheme payments and excluding RAB indexation



Source: Financial performance model.

Notes: Calculation details are in the financial performance model and EBIT per customer explanatory note. Averages are simple averages and nominal values are converted to $ 2022 terms.

65 We have published the financial performance datasets, which enables stakeholders to calculate the EBIT per customer (and return of assets and return of regulated equity), inclusive and exclusive of RAB indexation, incentive schemes and pass through revenues.

Our estimates of EBIT per customer for TNSPs are materially lower than for DNSPs. This is a consequence of the higher capital intensiveness of distribution networks compared to transmission networks—that is, distribution networks typically have larger RABs per customer. However, it does not mean that TNSPs are less profitable than DNSPs for the same levels of investment.

4.3 Returns on regulated equity

The return on regulated equity measures the final returns available to equity holders after all expenses. The return on regulated equity is influenced by the financing decisions of the NSP. Unlike the return on assets and EBIT per customer, the return on regulated equity is based on net profit after tax (NPAT) rather than EBIT. As such, it also captures returns arising from differences between an NSP's:

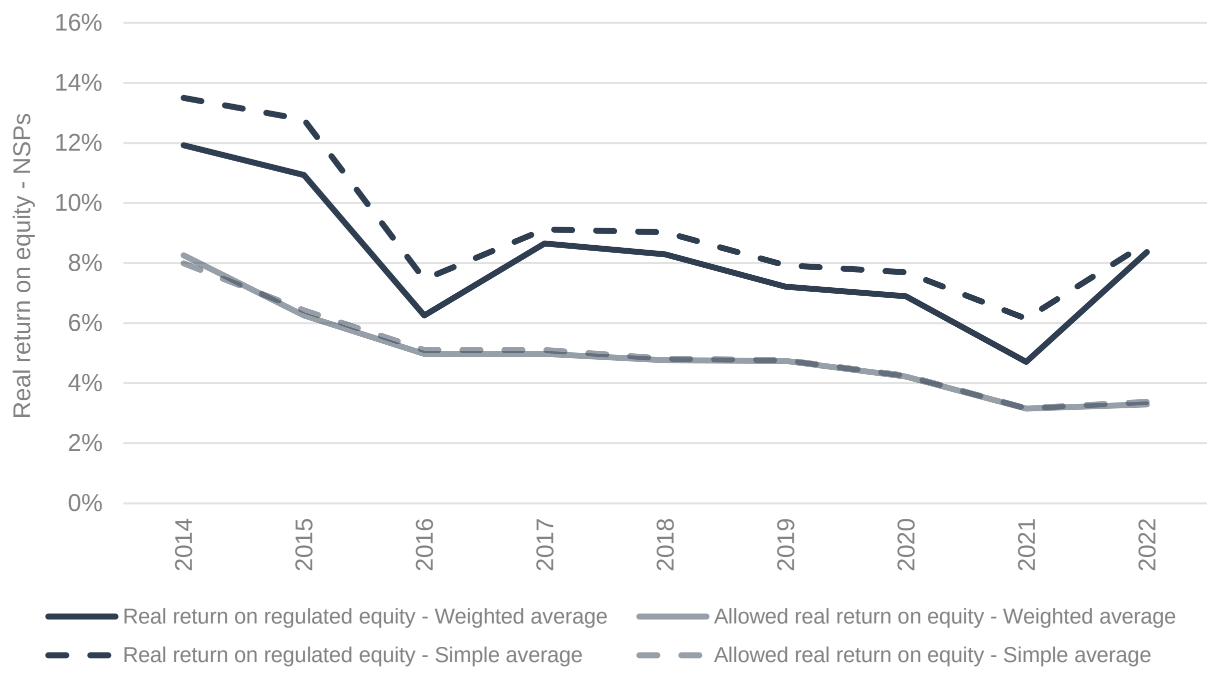
- actual tax expense and forecast tax allowance, and
- actual interest expense and forecast return on debt allowance.

The return on regulated equity is a measure that is bespoke to NSPs operating under our or comparable regulatory regimes. This measure therefore requires care to interpret and cannot necessarily be directly compared with returns on equity achieved by firms operating in the broader competitive market. Specifically, this measure reflects the treatment of network revenue and expenses in the building block revenue framework and in our models—for example, valuing network assets using the RAB rather than a separate book or market value. This is necessary for comparing the measure against our allowed returns on equity, but also means there are differences between our approach and how a return on equity would ordinarily be calculated. Our analysis and financial performance measures data should be considered alongside our profitability measures review final decision[66] as well as our explanatory note and illustrative return on regulated equity model published alongside this report.

Figure 22 presents actual and allowed returns on regulated equity as both a simple and weighted average of NSPs. We previously presented financial performance measures as simple averages (that is, each NSP is weighted equally). We will start reporting weighted averages more as we consider this better represents the average consumer or market impact. This year, we have published both types of averages to provide continuity with what we published in 2022 whilst also illustrating the impact of the different averaging approaches. For example, the average real return on regulated equity was materially lower on a weighted average basis in 2014. A large driver of this was that the Queensland DNSPs achieved the lowest returns on regulated equity (6.9% and 8.1%) but held 28% of the equity invested in NSPs.

66 AER, *Profitability measures for electricity and gas network businesses*, December 2019, accessed 7 June 2023.

Figure 22 Real returns on regulated equity versus allowed returns on equity—NSPs



Source: Financial performance model.

Notes: Calculation details are in the financial performance model, separate illustrative model and return on regulated equity explanatory note. Averages are weighted by each NSP's assumed regulatory equity base.

- Over 2014 to 2022, NSPs have on average been achieving returns on regulated equity that are higher than forecast.
- While average returns on regulated equity declined materially over 2014 to 2021, this occurred against a backdrop of declining forecast returns on equity. These declines occurred in an environment of:
    - Declining interest rates, including the rates on Commonwealth Government Securities on which we forecast the risk-free rate.
    - Our application of the 2013 rate of return guideline and, from 2020, the 2018 binding rate of return instrument.
- In 2022, weighted average NSP returns on regulated equity increased by over 3 percentage points relative to 2021.
- The higher measured returns on regulated equity achieved in 2022 are primarily due to a higher than expected inflation rate which increases returns from RAB indexation of the proportion of the RAB attributable to debt. We explain these drivers further in section 4.3.1 below.

We also observe that:

- Underneath the average results, there is a spectrum of outcomes between NSPs, with some earning persistently higher returns
- All but one NSP has achieved returns at or above their forecast returns in most if not all years.[67]

4.3.1 Drivers of differences in actual and allowed returns on equity

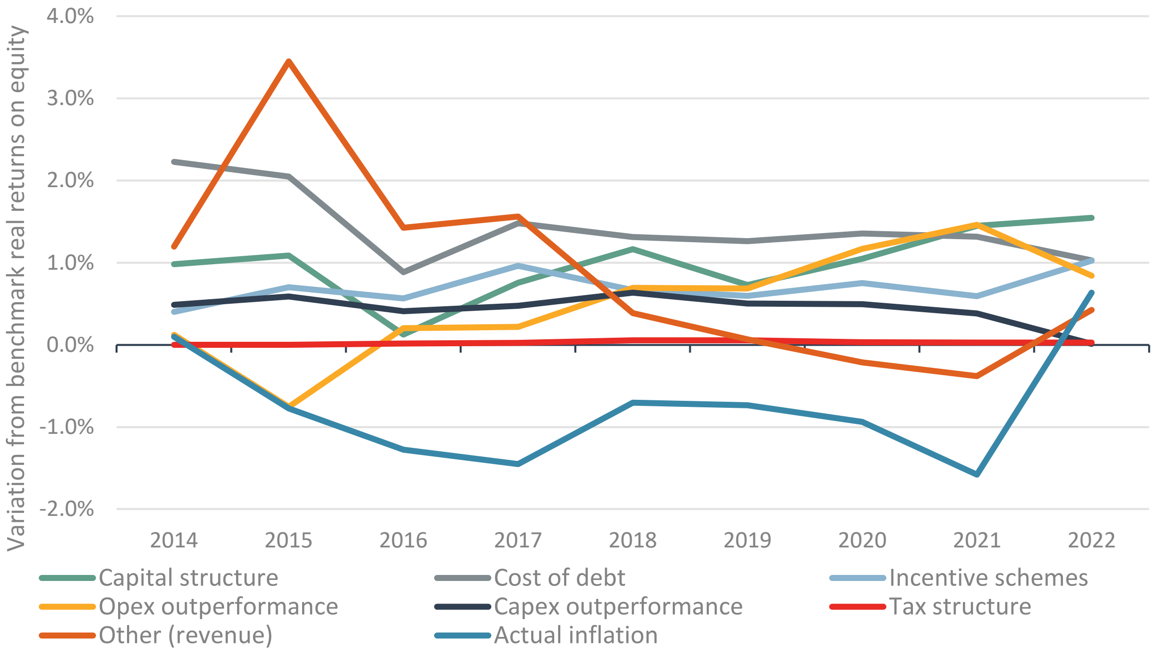
The framework is designed to encourage efficiency in the long run interest of consumers. Given this design, it is not unexpected that NSPs' returns would exceed allowed returns under a regulatory framework that provided them with a reasonable opportunity to recover at least the efficient costs of providing core regulated services.[68] However, whether these results are evidence of the framework operating effectively or not depends on the drivers and materiality of the results, including whether they are caused by:

- Temporary revenue over-collections arising from the normal operation of other features of the regulatory framework – such as the operation of approved revenue cap arrangements, which will be passed back to consumers in the short-term
- Departures from our benchmark financing structures – for example, in cases where some NSPs have taken on higher risk to achieve higher returns
- NSPs spending less than forecast revenue building blocks due to efficiency gains
- NSPs spending less than forecast revenue building blocks due to shortcomings in our approach to estimating network revenue requirements, or to forecasting errors that, if unbiased, might be expected to even out over time.

67 In 6 of 9 years from 2014 to 2022, Essential Energy did not achieve returns at or above the forecast returns.

68 As required under the National Electricity Law, 7A(2)(a).

Figure 23 Contributions to real* returns on regulated equity – NSP simple average



Source: PTRM and financial performance model (confidential version).

Notes: AER calculation of the differences in the return on regulated equity when reported actuals are substituted for AER benchmark allowances of each factor. For example, we substitute forecast opex from our PTRM in place of actual opex used in calculating the real return on regulated equity. We calculate the incremental change in returns with each new factor for each NSP in every year of the time series and take a simple average across all NSPs.

*Real returns exclude returns from indexation of the equity-funded portion of the RAB that would otherwise capture returns from differences in forecast and actual inflation, which are outside of an NSP's control. As debt is always in nominal terms, our estimates still capture some of the revenue impacts from differences in forecast and actual inflation through the indexation of the debt-funded portion of the RAB.

Figure 23 illustrates that a combination of factors has driven differences in the margin between allowed real returns on equity and actual real returns on regulated equity. It does not show the impact of tax structure, which was immaterial because most NSPs report being taxed as companies, National Tax Equivalent Regime (NTER) entities or government owned non-NTER entities where a tax rate of 30% applies.[69] The drivers shown in Figure 23 include:

- Capital structure, which reflects departures from the AER's benchmark financing structures. These departures do not result in consumers paying more for network services. Rather, these reflect that some NSPs have chosen to take on higher risk (by holding a higher proportion of debt) to achieve higher returns for themselves. Capital structure is currently the largest incremental driver of average outperformance, adding nearly 145 basis points to the average return on regulated equity in 2022.
- Cost of debt, which has a positive contribution if NSPs on average raise debt at a lower cost than what is provided for in the allowed return on debt. In 2022, this driver added over 100 basis points to the average return on regulated equity—which is a lower contribution than in most other years. This suggests that while NSPs have been able to raise debt at lower costs than our allowed return on debt, this has become more difficult to achieve.

69 Tax structure has a positive impact on the return on regulated equity for NSPs that operate under a flow-through tax structure, where a tax rate of less than 30% applies.

- Incentive scheme performance, which we calculate as the incremental change in returns after removing rewards or penalties received from incentive schemes. Incentives schemes will contribute to higher returns if on average NSPs receive higher incentive rewards than penalties. NSPs are rewarded under incentive schemes for beating their reliability targets, lower expenditure relative to their target expenditure or by achieving other performance levels (such as undertaking efficient demand management or achieving customer service goals). In 2022, this driver added about 100 basis points to the average return on regulated equity, which has been its highest contribution in our time series (starting 2014).
- Opex outperformance, which we calculate by substituting actual with forecast opex and calculating the incremental change in returns. Opex outperformance will contribute to a higher return if NSPs underspend their opex allowance. However, it does not reflect opex efficiency incentives under the EBSS, which are instead captured under incentive schemes. This has increasingly occurred since 2016, with opex outperformance adding about 130 basis points to the average return on regulated equity in 2022. Opex outperformance also benefits customers by reducing opex allowances in future years. We consider it would be insightful to explore the drivers of increasing opex outperformance in future reports, including by exploring the extent that the EBSS has driven efficiency gains.
- Capex outperformance, which we calculate by substituting actual with forecast capex and calculating the incremental change in returns. Capex outperformance will contribute to a higher return if NSPs underspend their capex allowance. However, it does not reflect capex efficiency incentives under the CESS, which are instead captured under 'incentive schemes'. Capex outperformance has had a consistently positive and relatively modest impact over the measurement period.
- Other (revenue effects). Revenue effects can lead to differences in allowed and actual returns on equity in any year but should even out over time. For electricity NSPs, which operate under revenue caps, revenue effects capture: (1) NSPs temporarily recovering higher or lower revenue than targeted through the revenue cap, (2) impacts of revenue smoothing, (3) changes in the annual revenue target to account for past over- or under-recoveries.
- Inflation rate variation, which we calculate by substituting actual with forecast inflation and calculating the incremental change in returns. In previous reports, we did not identify this effect on the basis that we presented returns on a real basis. However, we have since identified that our estimates of real returns on regulated equity do capture returns from inflation being higher or lower than forecast through the indexation of RAB, net of indexation returns to equity holders. Given we are identifying this effect for the first time, we provide further detail in section 4.3.2.

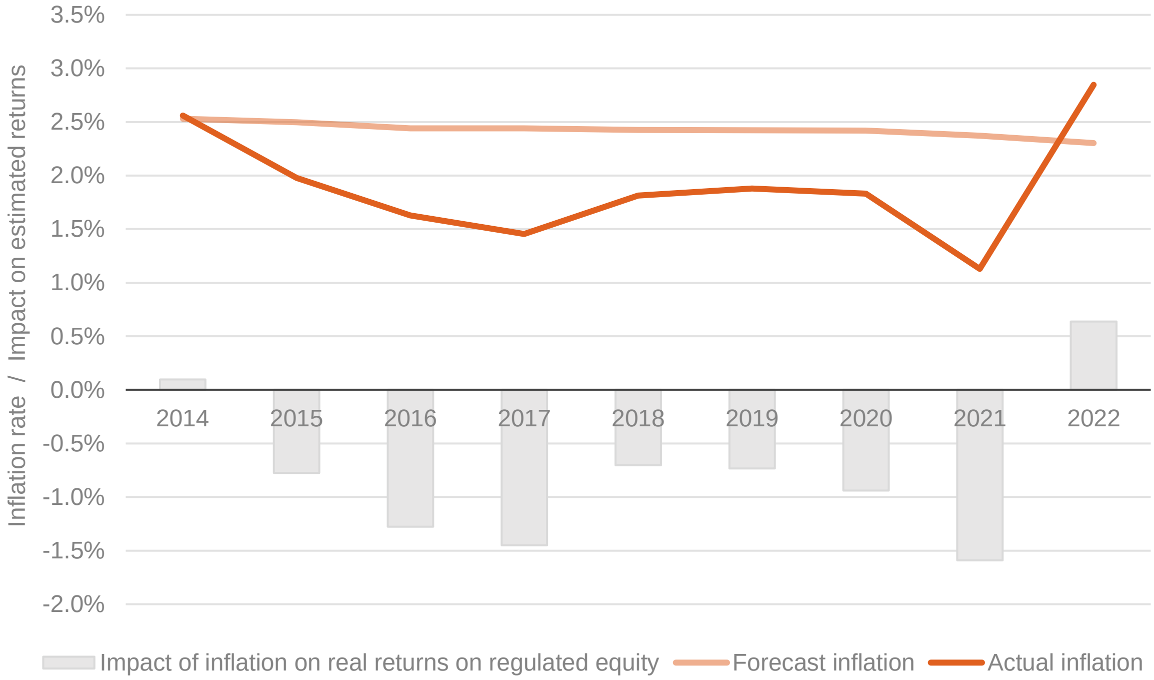
4.3.2 Impact of inflation on returns on equity

There has been a recent shift from a very low to materially higher inflation rate environment, contributing to higher returns on regulated equity achieved by networks. Figure 24 illustrates how this shift affected the actual inflation rate applied to index NSPs' RABs on average.[70] It also shows

70 The AER applies different inflation rates to index NSPs' RABs in accordance with each NSP's control mechanism. For example, relative to other NSPs, we index Victorian DNSPs with a greater lag. We describe this approach in AER, *Final decision: AusNet Services, CitiPower, Jemena, Powercor, and United Energy distribution determination 2021 to 2026: Attachment 14 – Control mechanisms*, April 2021, p. 26.

how actual inflation as measured by the Consumer Price Index (CPI) diverged from forecasts and the effect this had on real returns on regulated equity over the past decade.

Figure 24 Inflation impact on real returns on regulated equity compared with actual and forecast inflation



Source: PTRM and financial performance model (confidential version). Actual inflation data is sourced from the Australian Bureau of Statistics.

Notes: AER calculation of the differences in the return on regulated equity when actual inflation is substituted for the forecast used in the AER's revenue determination. Values are simple averages across all NSPs.

Figure 24 illustrates how differences between the forecast and actual inflation applied to index the RAB affects real returns on regulated equity. When inflation is below levels forecast by the AER, as occurred between 2015 and 2021, lower indexation of interest-bearing liabilities has had a negative impact on returns on regulated equity. When inflation is higher than CPI, as occurred in 2022, higher indexation has a positive impact on returns on regulated equity. These effects are amplified in networks that are financed with a higher proportion of interest-bearing liabilities than our benchmark gearing level of 60%.

It is worth noting that average actual inflation applied to NSPs' RABs in 2022 is low relative to the high inflation rate environment that year. This is because we apply indexation with a lag.[71] Given this lag, average actual inflation will be materially higher in 2023.

An unexpected high-inflation environment contributes to NSPs achieving higher returns in the short term. In the longer term, if increases in inflation rates are expected to be persistent, these expectations should be reflected in future revenue decisions, resulting in higher forecast inflation

71 This lag is particularly long for Victorian DNSPs, resulting in an actual inflation rate of 0.86% being applied to Victorian DNSPs in 2022 (compared to a rate of 3.5% being applied to non-Victorian DNSPs).

in subsequent regulatory control periods[72] and a lower likelihood of further returns from RAB indexation due to inflation being higher than expected.

As an outcome of our 2020 inflation review[73], we changed the inflation term from 10 years to 5 years. This allows our forecast inflation rate for new network determinations to be more responsive to changes in market circumstances. This change will likely lead to a lower difference between forecast and actual inflation than would have otherwise been the case.

Why indexation affects real returns on regulated equity

The National Electricity Rules require us to specify a method for indexing the RAB. RAB indexation compensates network businesses for the impact of inflation. As such, we target a real return for network businesses. Overall returns would not be lower in the absence of RAB indexation, as required by the rules.

Compared to including returns for inflation in the revenue allowance, indexation of the RAB leads to smoother revenue recovery and therefore prices. It also significantly reduces the short-term increase in revenues that invariably happens when assets are replaced at the end of their useful life.

Under our regulatory approach, we account for inflation by both targeting a nominal rate of return and indexing the RAB based on CPI data. We then apply a negative revenue adjustment (through depreciation) to ensure that the impact of inflation is not double counted.

To maintain consistency with this approach and reflect that debt is in nominal terms, we index the share of the RAB funded by interest-bearing liabilities when estimating regulatory NPAT used in calculating real returns on regulated equity. This differs from:

- Nominal returns on regulated equity: If we were to estimate nominal returns on regulated equity, we would also include returns from indexing the portion of the RAB funded by equity.
- Returns on assets: Indexation of interest-bearing liabilities does not affect returns on assets as these are based on EBIT, which captures earnings before interest and therefore excludes indexation of interest-bearing liabilities as well as interest expense.

Before RABs are indexed in line with actual CPI, the AER applies a forecast of inflation when modelling RAB growth and returns. As such, returns on regulated equity increase when CPI is higher than the forecast inflation rate. While this indexation affects actual returns on regulated equity achieved by NSPs, this does not result in immediately higher cash flows. Rather, this results in a larger RAB on which NSPs will earn revenue from higher returns on and of assets over the life of those assets.

Source: AER, *Why do we index the regulatory asset base?*, 2017.

72 See the revenue decision timetable in Figure 1

73 AER Inflation Review

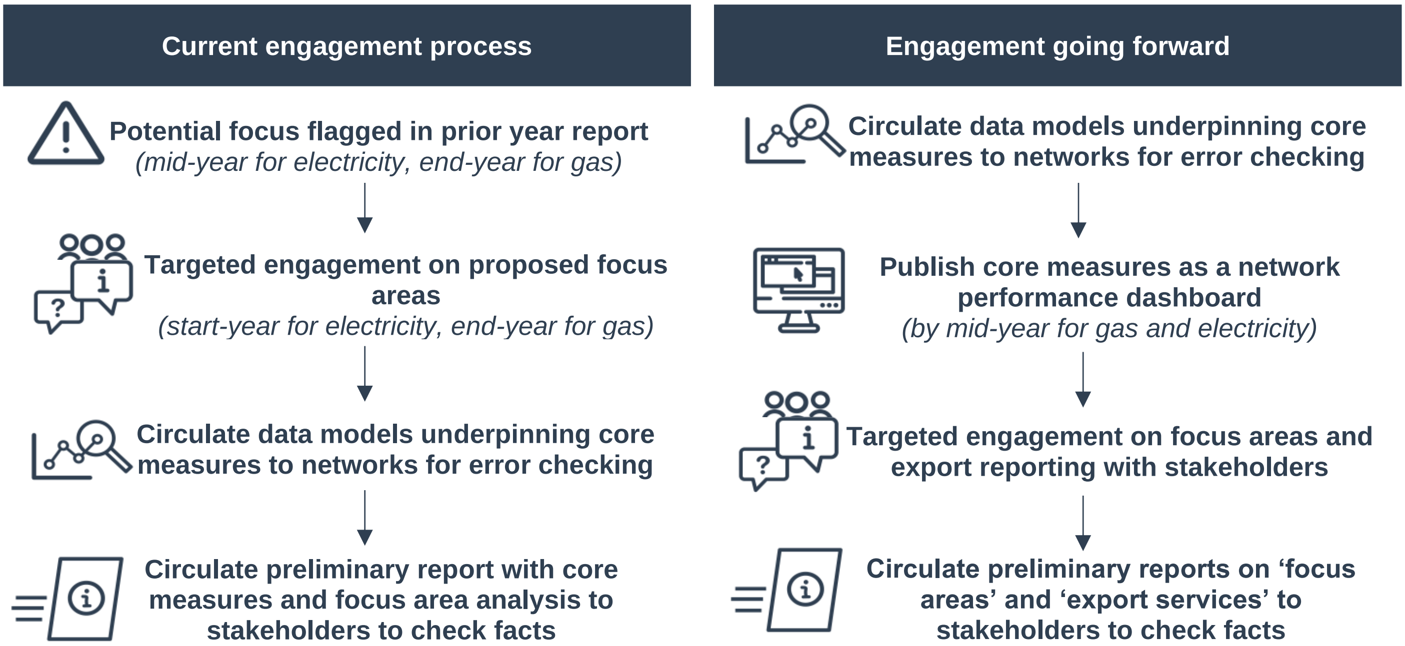
5 Looking ahead

Each year, we identify issues that could be investigated as focus areas in future electricity network performance reports. This year, we have issued a more streamlined report whilst separately developing:

- The inaugural export service performance report for release at the end of the year as a version update of this electricity network performance report. This report meets a new statutory requirement for the AER to publish annual reports on the performance of DNSPs in providing distribution services for embedded generators (such as residential solar) to export into the network.[74]
- A PowerBI network performance dashboard for release at the end of the year along with the AER's website upgrade. Our intention is for dashboards to provide a more use-friendly means for people to drill down into the measures and graphs presented in the written reports. We also anticipate this feature will enable more people the flexibility to access targeted networks data to undertake their own analysis.

In 2024, we intend to trial a new approach to our network performance reporting. Figure 25 summarises how the new approach would function relative to the current approach. Of note, under the new approach, we would align our timeframes for gas and electricity and work towards a mid-year release of core measures as a network performance dashboard.

Figure 25: Summary of new engagement approach to trial



Source: AER analysis.

74 As required under Rule 6.27A of the NER: *Annual DER network service provider performance report*, accessed 7 June 2022.

We consider this new engagement and report development approach would have the following benefits:

- Since we receive most of our data for gas and electricity network performance reporting near the end of each calendar year, we can have a timelier release of core measures data if we shift our focus area work to the second half of the calendar year. Under our current schedule, we release the gas network performance report when the latest year of data is over a year old. While network performance measures have traditionally moved gradually, more timely reporting will become more important as both the electricity and gas sectors are affected by the energy transition.
- Under our proposed approach, we would identify and consult on potential focus areas immediately before we commence our analysis. This approach should help us to explore topics that are timelier and more relevant, and to leverage off momentum provided by stakeholder interest. This contrasts to our current consultation process where we flag potential focus areas in the prior year's report—around 6 months before we commence our analysis.
- By consulting with stakeholders on focus areas immediately after releasing a new year's worth of data in the network performance dashboards, our engagement can be directly informed by emerging trends of interesting results in that data.

6 Appendix A: Objectives of network performance reporting

Through this report and the accompanying data, we intend to advance the network performance reporting objectives, determined with the input of stakeholders. These are set out in Table A-1.

Table A-1 How we are advancing our objectives for network performance reporting

Objective	What we are doing
Provide an accessible information resource	We have drafted this report to be informative and accessible for stakeholders. Alongside this report, we have published 2 data models covering: • Our operational performance data. • Our financial performance data. These models include much of the data captured in this report at a greater level of detail. We aim to present the data in a form that enables stakeholders to use it in their own analysis. We have also undertaken a survey of publicly available reporting on electricity network safety and have summarised our findings as a resource for stakeholders.
Improve transparency	Through the report and our published data, we are trying to illustrate the impacts and interactions of network performance under different regulatory tools or settings. The regulatory regime can be complex. Our objective through this reporting is to make network regulation and its outcomes more transparent for stakeholders. For example, in this report we have reported on the progress of network tariff reform.
Improve accountability	The focus of this report is on the effectiveness of network regulation as a whole, increasing our accountability for regulatory decisions and for the NSPs and their performance under those decisions. Further, our published data allows for comparisons of individual NSPs. Our published data and analysis highlights areas where particular NSPs depart from broader trends.
Encourage improved performance	By improving accountability and transparency, these reports should contribute to improved performance over time by: • Informing ourselves and stakeholders about emerging trends that may require a regulatory response. • Contributing to the incentives on NSPs to improve performance.
Inform consideration of the effectiveness of the regulatory regime	Our analysis in this report is intended to support consideration of how the regulatory regime contributes to network performance and outcomes. We aim to explore where actual outcomes depart from forecasts or trends, whether this is widespread and what implications that has for our regulatory approaches.
Improve network data resources	Through our analysis of the data, we have sought to: • Investigate and make use of a wide range of our network data sources. • Identify and manage differences in reporting which impede comparability of data provided by different NSPs. • Identify important questions on which we would like to form views but are limited by data availability or consistency. Over time, we expect this approach will also assist us to form a view on any data we currently collect which may be excessive or not useful.

Source: AER analysis; AER, *Objectives and priorities for reporting on regulated electricity and gas network performance—Final*, June 2020.

We welcome stakeholder feedback on the report and accompanying data resources so we can improve its usefulness over time. Stakeholders willing to provide input are encouraged to email networkperformancereporting@aer.gov.au.