Electricity and gas networks performance report 2025

December 2025

AUSTRALIAN ENERGY REGULATOR

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1 Executive summary

This is the AER's second combined annual electricity and gas networks performance report. The report analyses the key outcomes and trends in the operational and financial performance of the 19 electricity network service providers (NSPs) and 6 gas distribution network service providers (DNSPs) regulated by the AER under the National Electricity Objective (NEO) and National Gas Objective (NGO).[1]

Our network performance reports provide accessible information to improve the accountability and transparency of the regulatory regime. Our report includes analysis of actual network operational and financial performance against forecasts. We also provide observations about the shifts from past trends and how these changes interrelate with the energy transition to net zero emissions by 2050.

The regulatory framework and prescribed electricity and gas laws and rules are designed to create incentive-based regulation. Effective regulation of networks involves consumers over the long-term paying no more than is necessary for a safe and secure supply of energy.

This requires balance between the costs of providing network services and the outcomes arising from those costs. We have structured this report to provide the information necessary for stakeholders to consider how this is being achieved.

1.1 Key findings - Electricity

Electricity network costs decrease in 2024

In 2024, after adjusting for inflation (in real terms), electricity consumers on average paid less for electricity network services than the prior year.

This decrease was primarily due to two main factors, being network outperformance under incentive-based regulation driving lower expenditures, and favourable conditions in the external environment. During the 2015 to 2021 period, low interest rates and inflation had a beneficial effect in reducing the allowed rates of return set for networks. This has resulted in network costs for consumers in 2024 being substantially lower than the 2015 peak.

Higher inflation and interest rates in the period following 2022, have subsequently led to higher allowed rates of return for electricity NSPs. This could increase network costs in 2025 and the coming years.

Electricity distribution networks increase capex and the RAB

In 2024, electricity distribution networks increased their capital expenditure (capex) from 2023 and in aggregate overspent their collective annual capex allowance.

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[1] This report does not include any operational or financial data on the 3 scheme (transmission) pipelines. We report on these three gas transmission network service providers (TNSPs) through the operational and financial datasets (Microsoft Excel workbooks) and gas TNSP infographics published alongside this report. Further information on our reporting of these 3 gas TNSPs is provided in Appendix B.

This overspend was driven by Ergon Energy, who individually contributed to almost half of the overspend. In 2024, the capex investment also differed across the electricity DNSPs, with several networks spending less than their capex allowance.

Capex allowances are set for electricity distribution networks on a five year basis, and across the five years we expect capex patterns to fluctuate between underspend and overspend against their annual allowance. The collective overspend in the last two regulatory years for electricity distribution networks, follow underspends from 2020 to 2022.

The increased capex investment by electricity distribution networks will not have an immediate impact on the network costs for electricity consumers. This investment, which has increased the electricity distribution regulatory asset base (RABs) in real terms, will be gradually recovered from electricity consumers over the life of the network assets.

Electricity transmission networks increase RAB, despite slight decrease in capex investment

In 2024, electricity transmission networks' capex investment was slightly below 2023, with an underspend of their capex allowance. Despite the lower investment and underspend, the electricity transmission RAB increased in real terms.

The majority of this capex investment was in Integrated System Plan (ISP) projects, specifically Project EnergyConnect and HumeLink, which led to an increase in electricity transmission RAB in real terms. At the conclusion of the 2024 regulatory year, the total investment across ISP projects was $3.3b.

During the 2024 regulatory year, the AEMC made two rule changes to accommodate ISP projects into our regulatory framework. The first provides more flexibility to address financeability requirements, should they arise, to ensure the timely and efficient delivery of ISP projects. The second was to ensure the benefits of low-cost concessional finance are passed onto consumers.

Electricity networks have returns lower than allowed

Of the three profitability measures that we report on, the best measure of the financial performance of networks and whether they have achieved against the NEO and NGO is the return on assets (RoA) measure. This reports on whether networks have achieved operating profits above their allowed returns.[2]

In 2024, on a weighted average basis, the actual RoA of electricity networks decreased slightly from the previous year. This continued the gradual trend of decreasing RoA for electricity networks, and for the first time in our dataset, resulted in weighted average returns in 2024 being below the allowed rate of return. On an individual basis, the RoA varied from network to network.

The annual decrease was primarily due to electricity networks earning less than their allowed revenues and under recovering pass through costs. This related to the effects of annual revenue smoothing, electricity networks temporarily recovering less than their revenue cap

[2] This is earnings before interest and tax. It does not include the interest or tax expense of the networks.

and electricity distribution networks' transmission and jurisdictional revenues being less than their transmission and jurisdictional costs.

Lower inflation decreases electricity networks' returns to equity holders

The return on regulated equity (RoRE) is the network's net profit after tax (NPAT) divided by their regulated equity.[3] Under our regulatory framework networks bear the risk from actual inflation differing from expected inflation, as it is a more efficient allocation of risk. As a consequence, a networks' RoRE will be higher when inflation is higher than expected, whilst conversely the RoRE will be lower when inflation is lower than expected.

On a weighted average basis, electricity networks' RoRE decreased significantly in 2024. This decrease was primarily due to falling inflation. However as actual inflation was still higher than estimated in 2024, there was an increase in electricity networks' RoRE.

Overall, the gap between the weighted average actual RoRE and allowed returns, which widened as inflation rose from 2022, has significantly narrowed as the difference between actual and expected inflation has decreased.

In addition to inflation, the other drivers leading to the RoRE being above the allowed return on equity, were higher gearing than the benchmark gearing ratio in electricity networks' capital structures, electricity networks achieving a lower cost of debt and revenues from incentive schemes.

Electricity delivered increases, driven by non-residential consumers

The electricity delivered in 2024 increased slightly to 147,000 GWh, with the amounts delivered by each electricity distribution network differing according to the composition and size of their customer base. The increase was driven by non-residential electricity consumers, with the overall amount of electricity delivered to residential consumers decreasing slightly.

Since 2012, residential consumption per customer has been relatively constant. Increased consumption from a growing customer base and the electrification of household appliances has been offset by lower consumption from improved appliance efficiency and the use of consumer energy resources (CER), such as rooftop solar photovoltaic (PV) and batteries.

Going forward, we expect electricity consumption to increase, driven by a range of factors including a growing customer base, more households electrifying their household gas appliances and consumers replacing internal combustion engine vehicles with electric vehicles.

This increased consumption could be managed in part by electricity distribution networks increasing the utilisation of their existing network capacity. This could lead to lower unit costs

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3 As NPAT is the final or ultimate return to an NSP's equity holders, it captures the returns arising from differences between: a network's actual tax expense and forecast tax allowance and their actual interest expense and forecast return on debt allowance. The regulated equity is calculated by subtracting the network's interest-bearing liabilities from their RAB.

for the electricity delivered to electricity consumers, and a lower total network cost. In addition, by electrifying their gas appliances and using an electric vehicle, consumers could avoid gas and fuel costs and reduce their overall energy costs.

1.2 Key findings – Gas distribution networks

Gas distribution network costs remain low as consumers use less gas

The total revenue and revenue per customer for gas distribution network consumers in 2024, was the lowest in our dataset (after removing 2023 which was affected by the annualising of the six-month transitional period in Victoria). This was due to lower gas demand by residential and industrial customers, which led to an overall decrease in the total gas delivered across all gas distribution networks.

The decreased residential gas demand was in part due to milder temperatures which reduced demand for heating. Other reasons for the decrease in gas demand included the electrification of heating and cooking appliances and associated jurisdictional policies and consumer preference for lower gas use with cost-of-living pressures.

Going forward there is uncertainty in relation to the pace of decline in gas demand from the electrification of household appliances and other policy developments in the energy transition to net zero emissions. In AEMO's recent Gas Statement of Opportunities, the step change scenario's assumptions involves residential and commercial consumption declining from 176 PJ in 2025 to 51 PJ in 2044 despite rising population and economic growth.[4]

Gas distribution networks increase opex in 2024, but underspend opex allowance

In 2024, gas distribution networks incurred more opex than the prior year but collectively underspent on their collective opex allowance.

Gas distribution networks have had 7 consecutive underspends of their annual opex allowance (from 2018 to 2024). This opex efficiency benefits both gas networks and consumers; while lower opex enables gas networks to earn returns higher than their allowed returns, it will also result in lower opex forecasts in future access arrangements

Gas distribution networks decrease capex investment and underspend capex allowance

In 2024, gas distribution networks decreased their capex investment from 2023, and underspent their capex allowance. This resulted in a marginal increase in the total capital asset base (CAB) in real terms, with the total CAB per gas distribution customer remaining consistent with last year.

Gas distribution networks have traditionally been run as growth assets with costs spread over a growing customer base. Australia's energy transition to net zero emissions by 2050

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4 AEMO, 2025 Gas statement of opportunities, March 2025, p 23.

has seen the outlook of the distribution networks and gas as an energy source for gas distribution network consumers change.

Gas distribution network customer base increases slightly

In 2024, there was a slight overall increase in net residential customer connections, with all gas distribution networks except Evoenergy increasing their customer base. The 2024 regulatory year is the second consecutive year Evoenergy has decreased its customer base, following the implementation of the ACT regulations banning new gas connections.

The Victorian gas connections restrictions implemented in 2023 has not yet led to a decrease in the customer base of the Victorian gas distribution networks. This was due to customers with approved planning permits being connected after the restrictions were implemented and the new connections restrictions only applying to new dwellings which required a planning permit.

Gas distribution network returns decrease

In 2024, on a weighted average basis, RoA returns for gas distribution networks decreased, leading to actual returns which matched their allowed returns. On an individual basis, the RoA varied from network to network.

Although the opex efficiency of gas distribution networks had a positive impact on their RoA, the cumulative impact of revenue differences resulted in lower actual returns. These revenue differences related to revenue smoothing, revenue adjustments from previous access arrangements and lower revenues earnt under the weighted average price cap.

Gas distribution network returns to equity holders decreases

In 2014, on a weighted average basis, gas distribution networks had RoRE above their allowed return on equity in 2024, however these returns were lower than reported in 2023.

The decrease in RoRE was primarily due to a one-off revenue adjustment for Victorian gas distribution networks associated with their six month transitional access arrangement, which artificially increased their 2023 returns. This decrease was offset by higher allowed returns and an increase in the RoRE from actual inflation being higher than expected.

The higher inflation returns were due to the 18-month lag in applying an inflation rate of 7.8% for Victorian gas distribution networks against expected inflation, rather than the inflation rate of 4.1% for AGN (South Australia), Evoenergy and Jemena Gas Networks.

1.3 Summary of 2025 - Key findings

Key finding	Electricity networks	Gas distribution networks
Revenue	• Electricity network revenues decreased by 2.1% to $12.7b (real terms). This resulted in a $36 reduction in annual costs per customer. • Electricity network revenues remain significantly below their 2015 peak, in a period when reductions in allowed returns on capital and specifically lower rates of return began to be applied in networks' regulatory determinations. • Revenue per customer was the lowest it has been since before 2006 for both electricity distribution and transmission networks.	• Gas distribution revenues increased by 6.1% to $1.6b (real terms), or a $16 increase on a per customer basis compared to the previous year. However, the year-on-year comparisons are not reliable because of the effect of the annualising of only six months data in the 2023 year for Victorian gas distribution networks. • Historically, total revenue and revenue per customer in 2024 were the lowest in our dataset (commenced in 2011) after excluding the 2023 year.
Financial performance	• Electricity networks RoA decreased by 0.8 percentage points, continuing the trend decline in our dataset. For the first time in our dataset, actual returns in aggregate were below their allowed rates of return. • The lower actual RoA in aggregate was primarily due to electricity networks earning less than their allowed revenues and under recovering pass through costs. • The RoRE decreased significantly in 2024 for the first time since 2021 to 6.4%, primarily due to falling inflation. This has resulted in the gap between actual RoRE and allowed returns significantly narrowing to 3.1 percentage points. • The gap between the weighted average actual RoRE and allowed returns, which widened as inflation rose from 2022, has significantly narrowed as the difference between actual and expected inflation has decreased.	• Gas distribution networks RoA decreased by 0.6 percentage points, continuing the trend decline since 2015. In 2024, actual RoA matched allowed returns for the first time in our dataset. • The lower actual RoA in aggregate was primarily due to increases in opex efficiency, noting that the 2023 year was impacted by the annualising of six month data for Victorian gas distribution networks. • The RoRE decreased significantly in 2024 for the first time since 2021, to 8%, primarily due to falling inflation. The gap between actual and allowed returns significantly narrowed to 4.5 percentage points, as the difference between actual and expected inflation has decreased.

Key finding	Electricity networks	Gas distribution networks
Incentive schemes	• Electricity networks earned $391m in incentive revenues in 2024, the lowest since 2021, and 40% lower than the previous year. This was the first time incentive scheme revenues decreased since the introduction of the CESS. • The decrease was driven primarily by significantly lower EBSS rewards for Endeavour Energy and Ergon Energy, a STPIS penalty incurred by Ergon Energy, and lower overall EBSS, STPIS and CESS rewards for transmission electricity networks in 2024.	• Gas distribution networks earned $10m in revenues from incentive scheme rewards in 2024, representing less than 1% of total distribution revenues. • This was an increase of $12m from 2023, where gas distribution networks paid small penalties, but no revenues were earned.
Capex	• Electricity networks capex increased by 8% to $7.4b, in real terms and collectively overspent their capex allowance for the second consecutive year. In 2024, their collective allowance was exceeded by 7%, the largest since 2009. • This overspend was primarily driven by electricity distribution networks, with Ergon Energy individually accounting for almost half of this overspend. • Expenditure is expected to increase in future years as transmission networks undertake approved capex from ISP projects, including EnergyConnect and Humelink.	• Gas distribution networks capex decreased by 10% to $555m in real terms in 2024. • Gas distribution networks' capex is predominately new connections and mains replacements of cast iron pipeline for pipelines using polyethene or polyamide materials. • Mains replacement capex was invested by AGN South Australia, AusNet Services and Multinet Gas. Both AGN South Australia and AusNet Services plan to complete their mains replacement program in their current access arrangement period, whilst Multinet Gas plans to complete their program in 2031.
Asset bases	• There was a 3% increase in real terms in the RAB values for electricity networks in 2024. When disaggregated, electricity distribution network RABs increased by 2.8% and electricity transmission network RABs increased by 3.6%. • We expect capital investments from the ISP projects to increase the RABs for electricity transmission networks in future years.	• CAB values increased by 1.2% in real terms for gas distribution networks in 2024, reversing a three-year trend where there has been an average 1.0% annual decrease in real terms in the CAB value. • Accelerated depreciation will put downward pressure on CAB values in future years. This seeks to reduce the stranded asset risk associated from long term demand uncertainty.

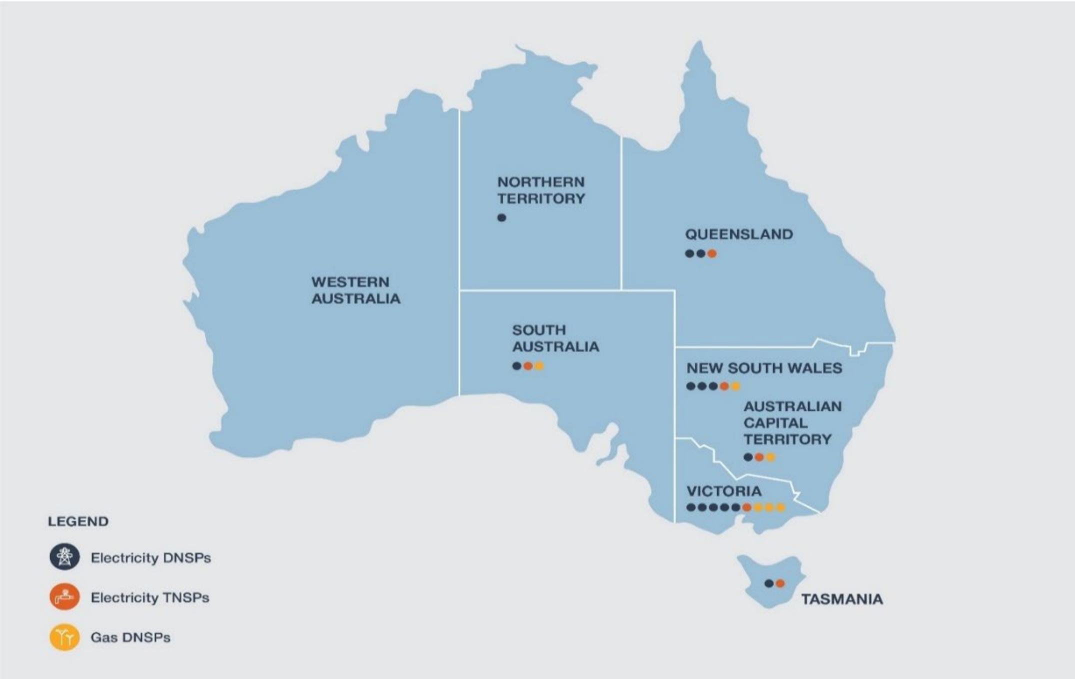
Key finding	Electricity networks	Gas distribution networks
Opex	• Opex was $4.5b for electricity networks, an increase of 7% in real terms. • Overall, electricity networks overspent their opex allowance for the regulatory year by 2%.	• Opex was $588m for gas distribution networks, an increase of 7%. • Although increased, gas distribution networks collectively underspent their opex allowance by 11% in 2024. This was the seventh consecutive underspend since 2018.
Network reliability	• Network reliability across electricity networks decreased slightly in 2024. • While the number of outages increased only slightly, the duration of outages increased more notably, due to a higher frequency and longer duration of other (unplanned) outages.	• Network reliability across gas distribution networks remained high in 2024. Unaccounted for gas improved slightly and outages continued at the same low levels as 2023.
Energy delivered	• Electricity delivered by electricity distribution networks was 147,000 GWh in 2024, an increase of 1.4% and the third consecutive annual increase. • Overall, the volume of non-residential electricity delivered increased, whilst the residential electricity delivered decreased slightly. • We expect electricity consumption to increase, driven by a range of factors including a growing customer base, more households electrifying their household gas appliances and consumers replacing internal combustion engine vehicles with electric vehicles.	• Gas delivered by gas distribution networks in 2024 of 270,000 TJs in 2024 is 10% lower, in comparison with the 2022 year. • The 2023 year has been impacted by annualising the six-month regulatory year for Victorian gas distribution networks, where there was an overrepresentation of warmer months. • Going forward there is uncertainty in relation to the pace of decline in gas demand from the electrification of household appliances and other policy developments in the energy transition to net zero emissions.

2 Background

The report is published in accordance with rules 6.27 (a) and (c), and 6A.31 (a) and (c) of the National Electricity Rules (NER), and division 5, section 64 of the National Gas Law (NGL).

The 25 NSPs included in this report are located in every state and territory in Australia except Western Australia.

Figure 2-1 Electricity NSPs and gas DNSPs regulated by the AER



The electricity NSPs and gas DNSPs regulated by the AER are located in all states and territories except Western Australia:

Queensland: The electricity DNSPs are Ergon Energy and Energex and the electricity TNSP is Powerlink.

New South Wales (NSW): The electricity DNSPs are Ausgrid, Endeavour Energy and Essential Energy and the electricity TNSP is Transgrid. The gas DNSP is Jemena Gas Networks.

Australian Capital Territory (ACT): The electricity DNSP is Evoenergy and the electricity TNSP is Transgrid. The gas DNSP is Evoenergy.

Victoria: The electricity DNSPs are AusNet Services, CitiPower, Jemena, Powercor and United Energy and the electricity TNSP is AusNet Services. The gas DNSPs are AusNet Services, AGN Victoria and Multinet Gas.

South Australia: The electricity DNSP is SA Power Networks and the electricity TNSP is ElectraNet. The gas DNSP is AGN South Australia.

Tasmania: The electricity DNSP and TNSP is TasNetworks.

Northern Territory (NT): The electricity DNSP is Power and Water Corporation.

2.1 Our objectives and stakeholder engagement

Through the history of our network performance reports and the accompanying datasets, we have advanced the network performance reporting objectives, determined with the input of our stakeholders.[5]

Table 2-1 How we are advancing in our network performance reporting objectives

Objective	What we are doing
Provide an accessible information resource	We prepare our network performance reports with the aim of making them informative and accessible to a wide variety of stakeholders. The reports present an analysis of the key operational and financial performance outcomes and trends of the NSPs we regulate over the relevant financial year. Alongside each report, we publish the underlying operational and financial performance data, enabling stakeholders to undertake their own analysis. Summarised data is also provided in electricity and gas infographics.
Improve transparency	In publishing our reports and accompanying data, our goal is to illustrate the impacts and interactions of network performance under different regulatory tools or settings. The regulatory regime is in a constant state of change and its operation can be complex. Reporting on the performance of NSPs under the different regulatory tools and settings, enables us to make network regulation and its outcomes more transparent for stakeholders. For example, throughout our reporting on profitability we have reported on actual NSP profits in a way we hope will assist stakeholders to: • Compare actual profitability against our allowed rate of return • Better understand the impact of pass throughs and incentive schemes on network profits. • Better understand the impact of inflation on NSP profitability.
Improve accountability	This report focuses on the overall effectiveness of network regulation and the performance of NSPs. The report increases our accountability for regulatory decisions and increases NSP accountability of their performance under those decisions. It also provides the opportunity to identify and inform stakeholders about emerging trends which may require a regulatory response. Our published data allows for comparisons of NSP performance, and in our analysis, we provide more context to stakeholders by highlighting particular areas where outcomes or efficiencies appear to differ between NSPs.
Encourage improved performance	Through improved accountability and transparency, we expect that over time these reports will contribute to improved performance by:

5 Stakeholder engagement is discussed further in section 2.2 of this report.

Objective	What we are doing
	• Encouraging NSPs to adopt more efficient processes and promote technologies applied successfully by better performing NSPs. • Contributing to the incentives on NSPs to improve performance, while maintaining efficient investment levels.
Inform consideration of the effectiveness of the regulatory regime	In this report specifically, we consider whether the outcomes of network regulation are achieving the objectives of the regulatory regime and the NEO. Where those outcomes depart from what we might expect, we are seeking to highlight this and explore possible drivers to provide more context to stakeholders.
Improve network data resources	Through our network performance reports, we have sought to: • Investigate and utilise 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, Objectives and priorities for reporting on regulated electricity and gas network performance, June 2020 and AER analysis

We have been publishing electricity reports since 2020 and gas reports since 2021. The effectiveness of our future reporting is dependent on stakeholders' feedback on both the report and our datasets so that we can improve their usefulness over time.

Publications that complement and may be read in conjunction with this report include:

- State of the energy market is published annually and provides a summary of the performance of electricity and gas markets at all stages of the supply chain, including wholesale markets, transportation and retail. The State of the energy market provides detailed overviews of how we regulate electricity and gas NSPs respectively.
- Insights into Australia's growing two-way energy system, our second annual export services network performance report, was published in December 2024. It assesses the performance of electricity DNSPs in providing services allowing customers to export energy back into the network and the progression of DNSPs towards becoming two-way platforms for energy services. We are required under NER to publish the next report no later than December 2025.

2.1.1 Stakeholder engagement for this report

In developing this report, we:

- sought a review of the draft report from NSPs and consumer representatives for factual accuracy, and
- provided NSPs with a copy of the supporting datasets to check for errors or omissions.[6]

2.2 Data used in this report

Data in this report is sourced from regulatory information notices (RINs), post-tax revenue models (PTRMs) and roll-forward models (RFMs), submitted to the AER by networks and published on the AER website. The length of the data series in this report and our datasets varies across the energy sectors and data types. Operational data for electricity NSPs begins in 2006 and for gas NSPs in 2011, while financial performance data for both sectors starts in 2014.

The NER and NGR specify that we may not publish NSP data that is considered confidential. Confidential data may include data that is identifiable to a third party or data that if disclosed may have a substantial adverse effect on the interests of that business.[7] Confidentiality claims over inputs for financial performance measures prevent us from publishing detailed input data, although we are still able to publish the resulting financial performance measures.

Given stakeholder interest we have again included the methodology we use to calculate the financial performance measures in Appendix D, E and F.

The accompanying datasets underpinning this report are provided in the operational and financial performance Microsoft Excel workbooks published alongside this report. We plan to replace some of these workbooks with Power BI dashboards when we complete further upgrades to our website.

2.2.1 The 2024 regulatory year differed across networks

In this report the 2024 regulatory year for NSPs is the period 1 July 2023 to 30 June 2024. The exception is AusNet Services (transmission) which had a regulatory year from 1 April 2023 to 31 March 2024, and the Victorian Transmission System which had a regulatory year from 1 January 2024 to 31 December 2024.

Previously, the Victorian gas DNSPs 2023 regulatory year consisted of the period 1 January to 30 June. In 2023, these DNSPs underwent a transition following an amendment by the Victorian Government, that extended the cessation date for their 2018-22 access arrangements to 1 July 2023 and provided that the six-month period would be considered an extra regulatory year. The 2024 report is the first year that the Victorian gas DNSPs regulatory year commences on 1 July (1 July 2023 - 30 June 2024). We discuss this further in chapter 4.

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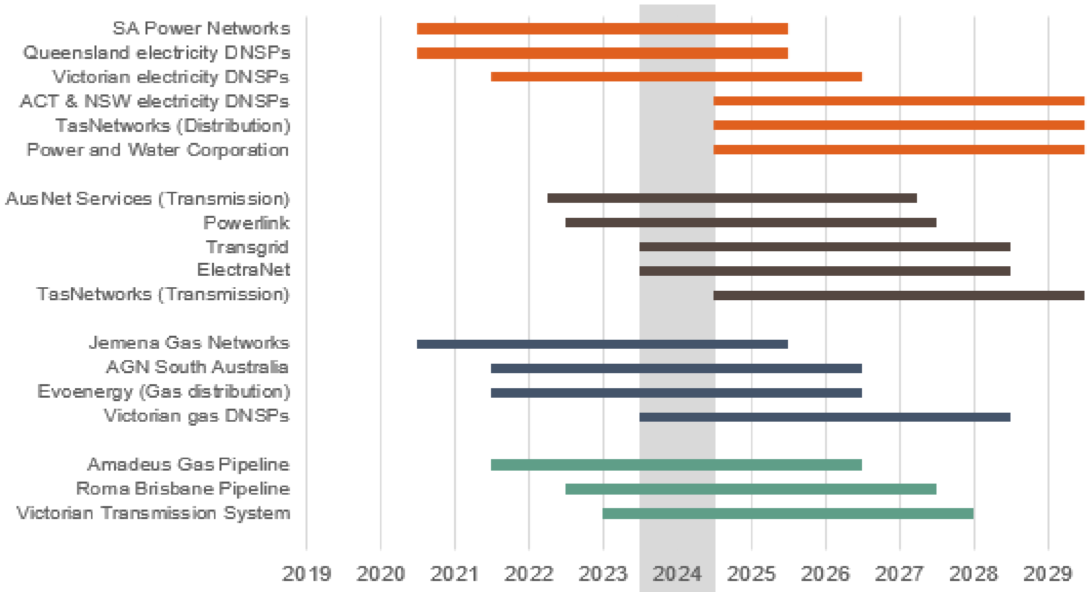
6 We completed this consultation in compliance with 8.7.4 (a), (b), & (c) of the NER and 140 of the NGR.

7 ACCC/AER, Information policy, June 2014, p 9.

Our regulatory periods and access arrangements typically apply over 5-year periods. We make these decisions for electricity and gas NSPs in a staggered cycle (Figure 2-2).

Figure 2-2 Electricity and gas NSP regulatory determination periods



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

The regulatory cycle is generally considered to commence with the determination of the electricity DNSPs in ACT, NSW, Tasmania and the NT. This is based on these regulatory determinations being the first to have periodically implemented substantial changes in regulatory settings (e.g., 2013 Better Regulation; 2018 Rate of Return Instrument).

3 Electricity network operational performance

This chapter focuses on the performance of electricity NSPs in the 2024 regulatory year.[8] References to NSPs in this chapter relate to electricity DNSPs and TNSPs.

3.1 Network costs decreased in 2024

3.1.1 Electricity network revenue continued to decrease

NSPs are monopoly businesses that provide essential services to customers. The AER is required under the NER to regulate the revenue NSPs are allowed to collect. We set the allowed revenue, based on our assessment of forecast efficient costs, which enables NSPs to fund their operations and receive a market rate of return on their capital investments. These costs are set in a manner which incentivises NSPs to make efficiency gains through reducing costs, whilst improving services for customers. Most customers pay network costs through network tariffs that are passed on to them through their electricity retailer.

All NSPs are regulated under a 'revenue cap.' This means they annually set prices to earn the maximum revenue allowed under the revenue cap. We set the maximum allowed revenue so NSPs can recover the costs an efficient network would incur in providing core regulated services.

Distribution and transmission revenue relates to revenue collected for core regulated services: standard control services for DNSPs and prescribed transmission services for TNSPs, as defined by the NER. These services include most energy transportation, connections and metering and represent the majority of an NSP's revenue.

In 2024, network customers paid an average of $1,152 in revenues to NSPs. Of this, $933 was paid to DNSPs and $219 to TNSPs. This is a decrease of $36 in real terms compared to 2023. In total, NSPs recovered $12.7b from customers, 2.1% less than the previous year.

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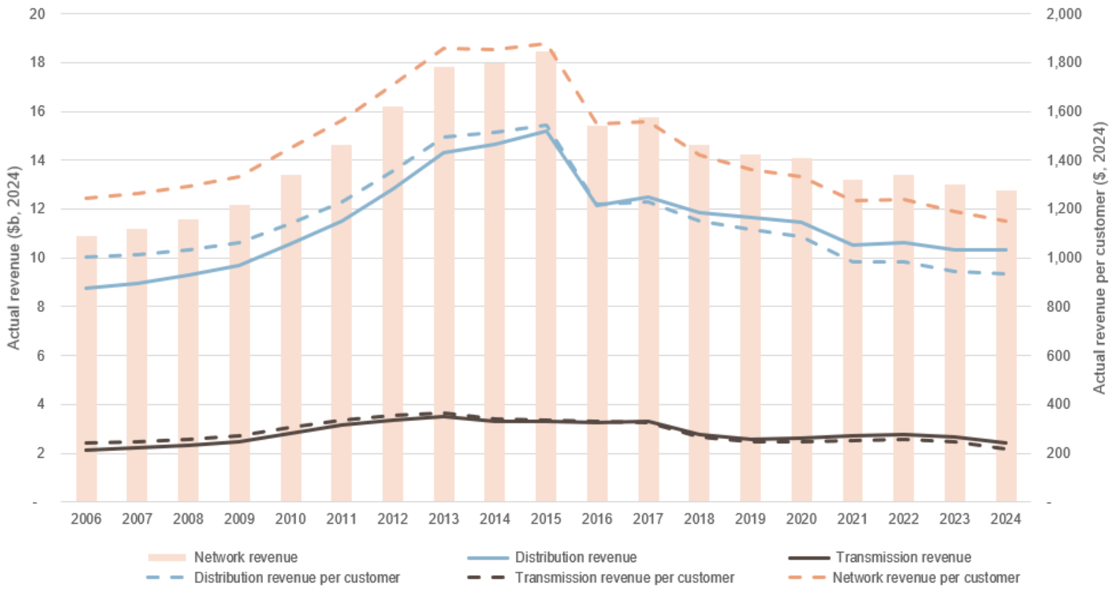
8 Refer to section 2.2.1 for details of each NSPs regulatory year.

Figure 3-1 Network revenue - NSPs - $ real 2024



Source: Network revenue: 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 (EB) RIN table 3.1.1, ‘Revenue grouping by chargeable quantity’. Network revenue per customer: Revenue provided above. Customer number data is from EB RIN table 3.4.2, ‘Distribution customer numbers by customer type or class.’
Note: AER calculation to convert to $ June 2024 terms. Network revenue is the sum of distribution and transmission revenue. DNSP revenue per customer calculated by dividing DNSP’s revenue by DNSP’s customer numbers. TNSP revenue per customer calculated by dividing TNSP’s revenue by the sum of distribution customers located in the same region as the TNSP.

Overall network revenue in 2024 was the lowest it has been since 2010. Revenue per customer for TNSPs and DNSPs in 2024 was also the lowest it has been since the commencement of our dataset in 2006.

3.1.2 Incentive schemes revenues decreased for first time since 2021

The regulatory framework incentivises NSPs to improve customer outcomes by increasing their efficiency, reducing costs, and improving service performance. This is accomplished through incentive schemes which provide a monetary benefit for meeting performance targets or imposing a penalty for falling short of performance targets.

Incentive schemes are designed to motivate NSPs to take actions that benefit customers. The goal of incentive schemes is to ensure that the overall benefit to customers outweighs the incentive revenue provided to the NSP. These schemes effectively align NSPs’ interests with those of the customers.

Table 3-1 Incentive schemes - NSPs

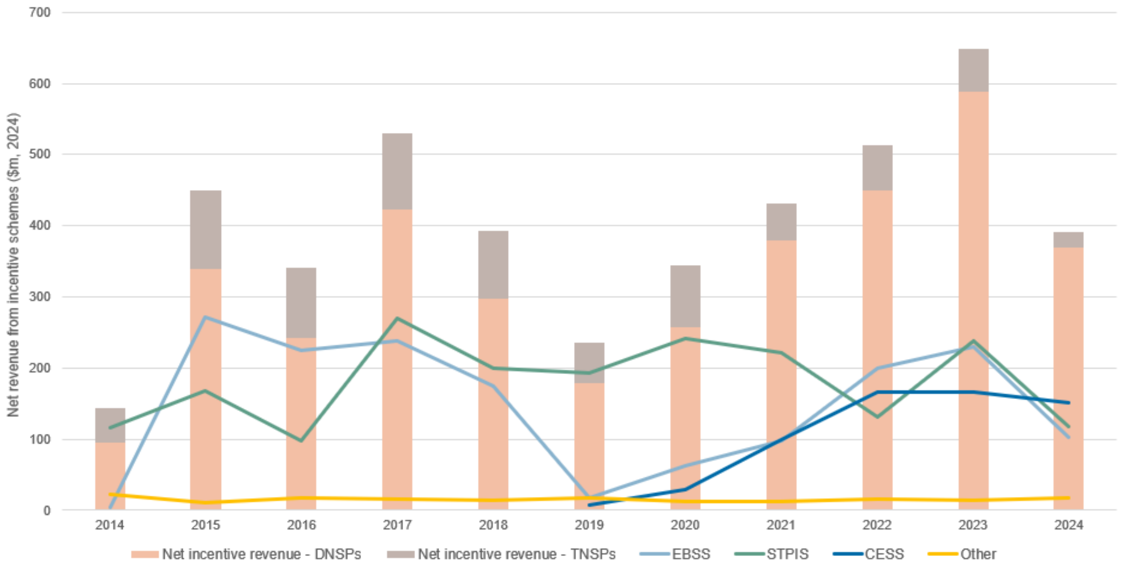
Objective	What we are doing
Efficiency benefit sharing scheme (EBSS)	Incentivises NSPs to reduce their operational expenditure (opex) by allowing them to keep opex savings for 6 years after they are reduced. Revealed efficiencies are then reflected in lower opex allowances in future years.
Capital expenditure sharing scheme (CESS)	Incentivises NSPs to reduce their capex by allowing them to keep up to 30% of capex savings in their regulatory period. Revealed efficiencies are then reflected in lower capex allowances in future years.
Service target performance incentive scheme (STPIS)	Incentivises NSPs to meet reliability by allowing them to earn additional revenue when reliability targets are exceeded. For DNSPs, reliability is based on number and duration of service outages (see below). TNSPs are also incentivised to improve network capacity and reduce the impact of interruptions on the wholesale energy market. Reliability targets achieved then form the performance targets for the next round of STPIS incentives.
Demand management incentive scheme (DMIS)	Incentivises NSPs to reduce expenditure on network upgrades by using non-network solutions to reduce peak electricity demand.
F-factor scheme	Incentivises DNSPs to reduce the risk of fire starts and the loss or damage they cause. Schemes introduced by the Victorian government following the Black Saturday Bushfires in 2009.
Customer service incentive scheme (CSIS)	Incentivises DNSPs by rewarding the DNSPs that exceed customer service targets.

Source: AER Analysis

During 2024, NSPs earned $391m in incentive revenues, the lowest since 2021, and 40% lower than the previous year. This has been primarily driven by:

- significant decreases in EBSS rewards by Endeavour Energy ($74m) and Ergon Energy ($39m) with smaller differences between actual and allowed opex.
- Ergon Energy incurring a service target performance incentive scheme (STPIS) penalty of $17m, for reduced reliability in previous regulatory years after earning $51m of rewards in 2023.
- Lower EBSS ($9m), STPIS ($17m) and CESS ($15m) rewards for TNSPs in 2024.

Figure 3-2 Revenue from incentive schemes - NSPs - $ real 2024

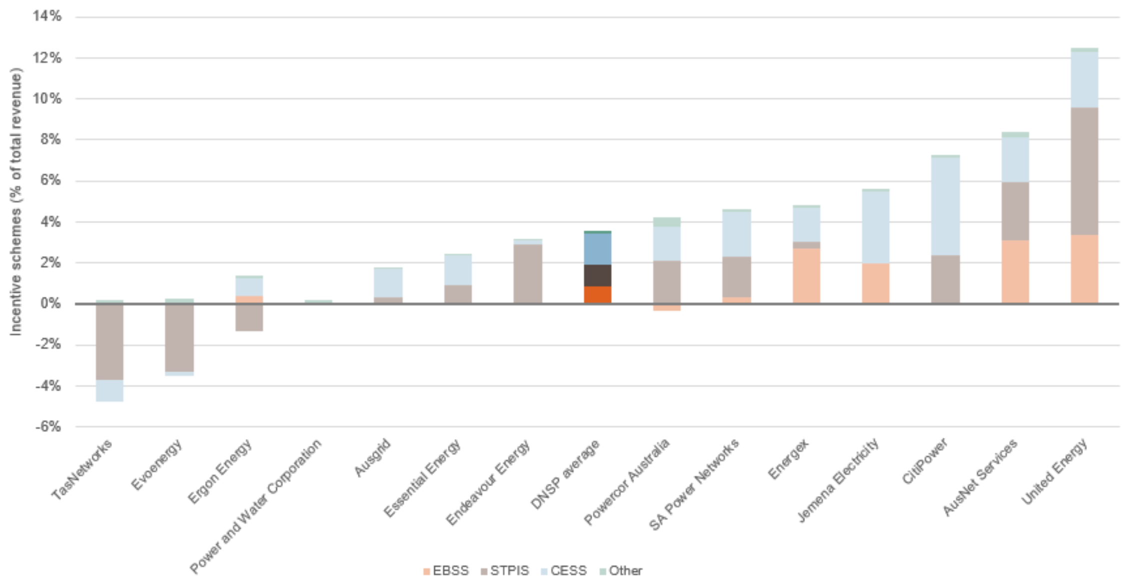


Incentive scheme revenues/payments from EB RIN table 3.1.3, ‘Revenue (penalties) allowed (deducted) through incentive schemes.’ Where not available, data is from respective NSP’s PTRM, ‘Revenue adjustments.’
Notes: AER calculation to convert to $ June 2024 terms.

In 2024, 3.6% of distribution revenue and 0.9% of transmission revenue was attributable to incentive schemes. Overall, 3.1% of network revenue was attributable to incentive schemes.

The revenues earnt from incentive schemes varied across DNSPs, with United Energy receiving the highest revenues from incentive schemes at 12.5% and TasNetworks having the lowest, with net payments of 4.6% of revenue.

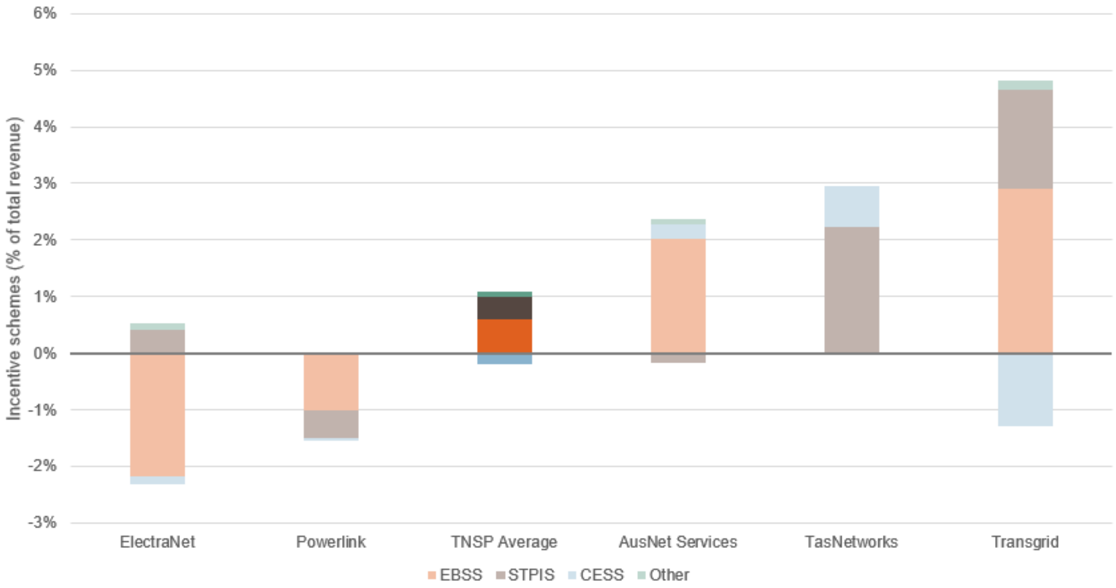
Figure 3-3 Distribution revenues from incentive schemes - 2024 - $ real 2024



Source: Distribution revenue: Annual RIN table 8.1.1.1, ‘Revenue - standard control services’ for DNSPs. Where annual RIN data is not available for DNSPs, data is from EB RIN table 3.1.1, ‘Revenue grouping by chargeable quantity’. Incentive scheme revenues/payments from EB RIN table 3.1.3, ‘Revenue (penalties) allowed (deducted) through incentive schemes.’ Where incentive schemes revenue/payments are not available, data is from respective NSP’s PTRM, ‘Revenue adjustments.’
Note: Other relates to the s factor true up, F Factor, DMIS/DMIA, and any other incentive schemes

The variability in revenues is also evident across TNSPs, however as seen last year,[9] there is a lower range between the amount of revenue attributable to incentive schemes. This is due to the lower total revenues from EBSS, STPIS and CESS for TNSPs in 2024 as provided above.

Figure 3-4 Transmission revenues from incentive schemes - 2024 - $ real 2024



Source: Transmission revenue: EB RIN table 3.1.1, 'Revenue grouping by chargeable quantity'. Incentive scheme revenues/payments from EB RIN table 3.1.3, 'Revenue (penalties) allowed (deducted) through incentive schemes.' Where incentive schemes revenue/payments are not available, data is from respective NSP's PTRM, 'Revenue adjustments.

3.1.3 Cost pass through events increased electricity network costs

The NER allow NSPs to recover costs associated with unforeseen events that are outside of an NSP's control.[10] Costs must be material and may be passed through to customers only if they exceed 1% of an NSPs annual revenue allowance.

Cost pass throughs are more frequently positive (increasing allowed revenue) and less frequently negative (decreasing allowed revenue). Cost pass throughs may either directly increase the revenue allowed to be collected by an NSP, or they may increase revenue in future years by increasing the NSP's capex allowance, which flows through to increase the NSP's RAB.[11]

In 2024, NSPs recovered an additional $198m from pass through revenues - approximately 1.6% of its forecast revenues. As with prior years, the main driver of cost pass throughs in 2024 were natural disasters, which increased allowed revenues by $66m, followed by tax ($57m) and regulatory requirements changes ($46m). These related to cost pass throughs that were lodged by NSPs in the period 2020 to 2024 and determined predominately before the start of the 2024 regulatory period.

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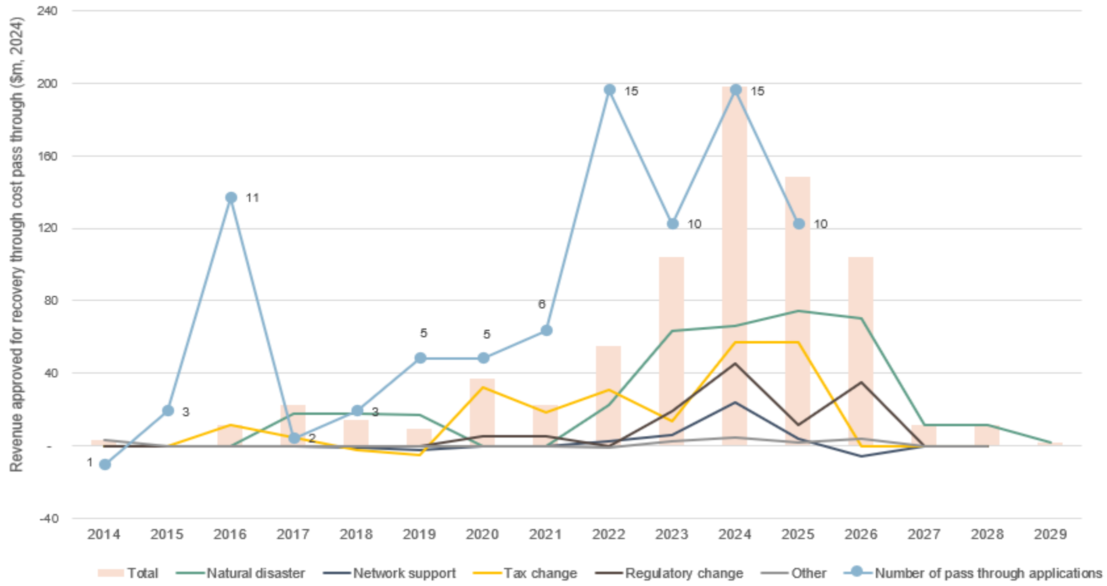
9 AER, 2024 Electricity and gas networks performance report, September 2024, p 23.

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

11 This is through additional returns from the return of capital and return on capital building blocks.

Figure 3-5 Revenue from cost pass throughs - NSPs - $ real 2024



Source: AER analysis of decisions under AER, Cost pass-throughs, accessed 24 March 2025.
Note: Calculation to convert values to $ June 2024 terms. Includes approved cost pass-through applications lodged to March 2025. Excludes jurisdictional scheme cost pass throughs.

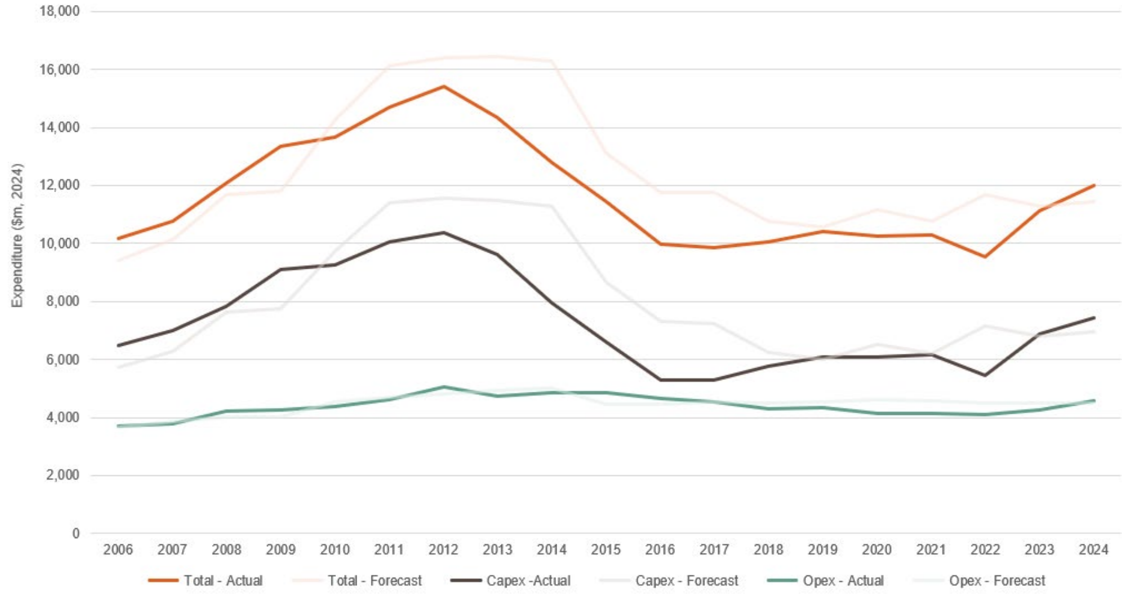
In 2024, we received 15 pass through applications and made decisions on 9 that were lodged in 2024, with the other 6 determined in 2025. These pass throughs primarily increased allowed revenues in 2024 and 2025. In the 2025 regulatory year, we have received 10 pass through applications, four relating to storm natural disasters in NSW, Queensland, Tasmania and Victoria and 2 relating to cyclones in Queensland. If approved, these will predominately increase allowed revenues in the 2026 regulatory year.

3.2 Expenditures increased as networks in aggregate overspent their allowance

An NSP's total expenditure is the sum of operating expenditure (opex) and capex. Opex comprises of day-to-day business expenses while capex is spent on longer term investments, most notably in network infrastructure. The regulatory framework is designed so that NSPs recover revenue for opex within the 5-year regulatory period through the opex allowance building block, while capex is added to the RAB (see below) and recovered over the life of the asset in the return of capital building block.

We set forecasts for opex and capex in a manner that incentivises NSPs to reduce costs. Opex and capex efficiency against an NSP's allowance leads to lower forecast expenditures in future years, ultimately leading to lower network costs for customers. Further, capex allowances are set as a total on a five-year basis, and we expect the capex patterns of NSPs to fluctuate between underspend and overspend against their annual allowance. Due to these factors, the expenditures of NSPs have varied over time.

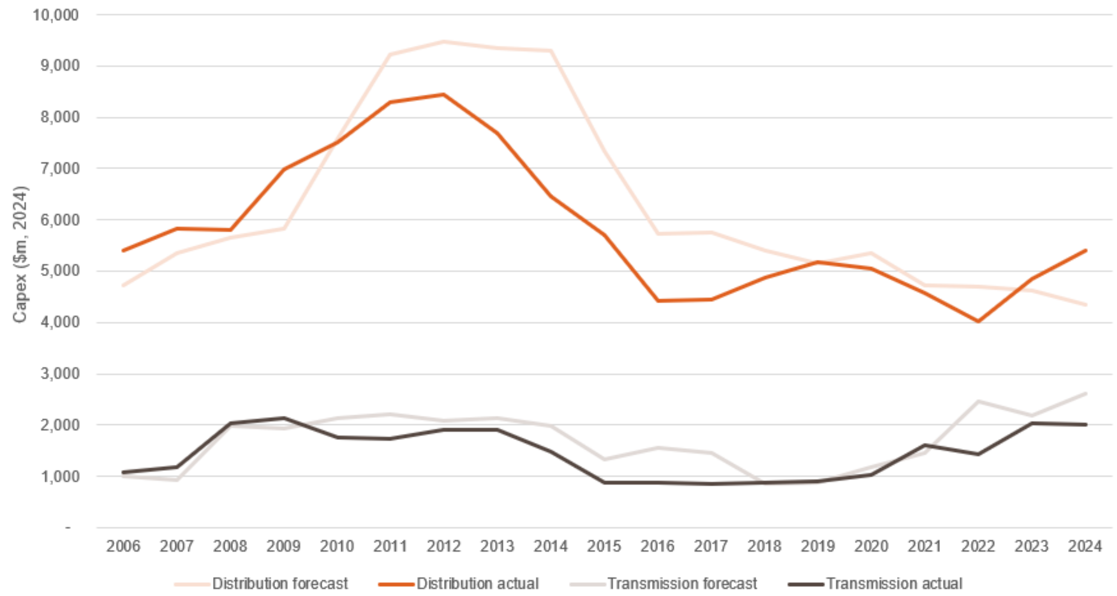
Figure 3-6 Total expenditure - NSPs - $ real 2024



Source: Actual capex: RFM input - ‘Actual capex,’ ‘Actual asset disposal,’ ‘Actual capital contributions.’ Where RFM not available for TNSPs, use category analysis (CA) RIN: 2.1 Expenditure Summary, (ii) for DNSPs, use annual RINs: Table 8.2.4 ‘Capex by asset class,’ Table 8.2.5 ‘Capital contributions by asset class,’ Table 8.2.6 Disposals by asset class. Actual opex: EB RIN - Table 3.2.2 ‘Opex’. Forecast capex: PTRM Input - ‘Forecast net capex.’ Forecast opex: PTRM Input - ‘Forecast operating and maintenance expenditure.’
Note: AER calculation to convert values into $ June 2024 terms. Net capex is gross capex less capital contributions and disposals.

When compared to previous year, NSP actual expenditure in 2024 increased by 8% to $12.0b, exceeding their forecast expenditure by 5%.

Figure 3-7 Capex - NSPs - $ real 2024



Source: Refer to actual and forecast capex from Figure 3-6.
Note: AER calculation to convert values into $ June 2024 terms. Net capex is gross capex less capital contributions and disposals.

In 2024, DNSPs overspent their capex allowance, whilst TNSPs underspent their capex allowance. This resulted in NSPs actual capex exceeding forecast by 7%, with 2024 being the second consecutive regulatory year NSPs have overspent their capex allowance. DNSPs contribution to this overspend was 233% with Ergon Energy individually accounting for 113% of the total NSP capex overspend.

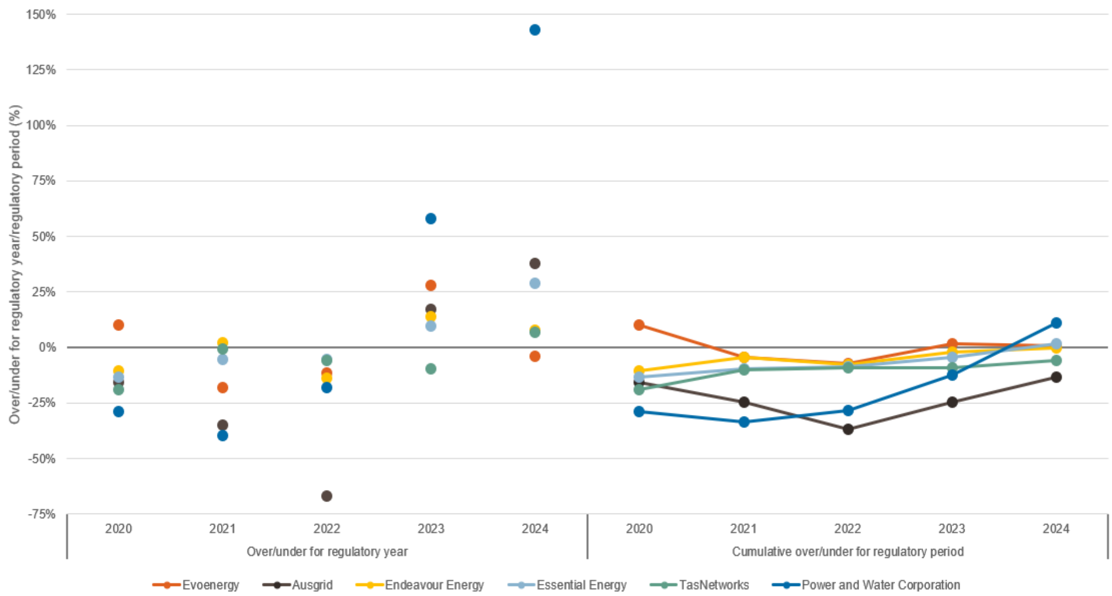
3.2.1 Timing of capex fluctuates within a regulatory period

We set capex allowances as a total over a five-year basis and expect capex patterns of NSPs to fluctuate between underspend and overspend against their annual allowance. There are different factors that can determine patterns of capex, which relates to capex incentives, financial or otherwise, which vary through the course of the regulatory period.

3.2.1.1 ACT/NSW DNSPs, TasNetworks and Power and Water Corporation capex

For ACT/NSW DNSPs, TasNetworks and Power and Water Corporation the capex patterns have varied across their current regulatory period, with annual overspends of capex allowances in 2024 by each DNSP except Evoenergy. Overall, for the 2019-24 regulatory period Evoenergy, Endeavour Energy and Essential Energy had capex investments approximate to their allowances, whilst there was an overspend by Power and Water Corporation and underspends by Ausgrid and TasNetworks.

Figure 3-8 Over/under spend of capex allowance for current regulatory period - NSW DNSPs, TasNetworks and Power and Water Corporation - $ real 2024

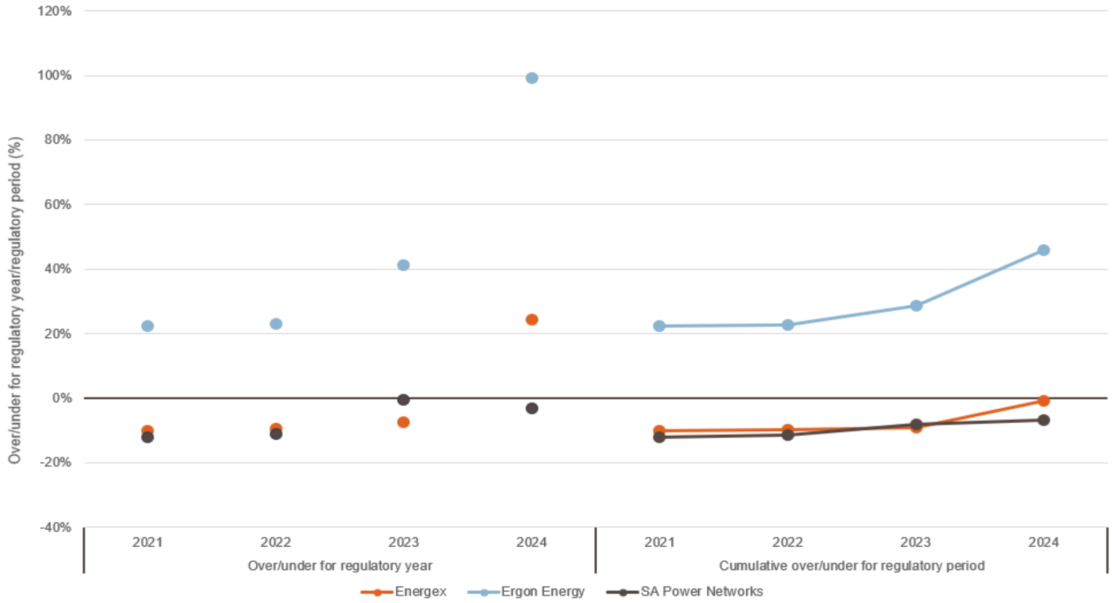


Source: Refer to actual and forecast capex for DNSPs from Figure 3-6.
Note: AER calculation to convert values into $ June 2024 terms. Net capex is gross capex less capital contributions and disposals. Capex over/under calculated by comparing total actual capex against total forecast capex for regulatory period.

3.2.1.2 Energex, Ergon Energy and SA Power Networks capex

In comparison for DNSPs with a 2020-25 regulatory period, Ergon Energy capex investment in the last four years, contrasts to Energex and SA Power Networks, who have primarily underspent their capex allowance. This overspend by Ergon Energy peaked in 2024, with an overspend 99% above their capex allowance.

Figure 3-9 Over/under spend of capex allowance for current regulatory period - Energex, Ergon Energy and SA Power Networks - $ real 2024



Source: Refer to actual and forecast capex for DNSPs from Figure 3-6.
Note: Refer to Figure 3-8.

In our regulatory determinations, we consider whether any capex overspends by NSPs from the last two years of their previous regulatory period and the first three years of their current regulatory period are to be included in the opening balance of the RAB for their next regulatory period. These considerations are made in accordance with the ex post measures for efficient capex from our Capital expenditure incentive guidelines for electricity NSPs, which enables overspent capex that does not reflect the capex criteria to be excluded from the RAB.

The capex criteria are contained in clauses 6.5.7(c) and 6A.6.7(c) of the NER and require us to be satisfied that capex is prudent and efficient and based on realistic demand forecasts. In determining whether we are satisfied the capex criteria is met, we must consider the capex factors in clause 6.5.7(e) and 6A.6.7(e) of the NER.[12]

In last year's report we noted that the capex investment compared to forecast differed amongst the DNSPs and across their regulatory periods. In this discussion, we noted that Ergon Energy had significantly overspent their capex allowance (for four consecutive years) when compared to other DNSPs for whom we have recently made a regulatory determination.[13]

In our draft determination for Ergon Energy's capex overspend in the ex-post period (2018-23), we did not include their overspend of $1.167m[14] into the opening RAB for the 2025-30 period.

12 AER, Capital expenditure incentive guideline for electricity NSPs, August 2025, p 2.

13 This includes final determinations on Evoenergy, Ausgrid, Endeavour Energy, Essential Energy (made in April 2024) and Energex, Ergon Energy and SA Power Networks (made in April 2025).

14 The amount of $1,195m was adjusted into June 2024 terms.

Table 3-2 Ergon Energy Ex-post review - $ real 2024

Capex category	AER Forecast 2018-23 ($m)	Actuals 2018-23 ($m)	Assessed overspend ($m)	Overspend in opening RAB ($m)
Repex	967	2,170	1,203	658
Augmentation (Augex)	391	223	(168)	(168)
Net connections	265	308	43	43
Other	442	549	(4)	(4)
Capitalised overheads	920	1,012	92	55
Total capex	**2,984**	**4,261**	**1,167**	**585**

Source: AER, Draft decision - Ergon Energy 2025-30 - Capex, September 2024, p 6.
Note: As Ergon Energy accepted our draft determination, the amounts in Table 3-2 were reflected in Ergon Energy's final determination for the 2025-30 period. These amounts have been converted to $ June 2024 dollar terms.

Alternatively, we included an overspend of $585m[15] into the opening RAB, a 50% reduction when compared to Ergon Energy's proposal. Ergon Energy accepted our draft decision on the outcome of the 2018-23 ex-post review, which was reflected in our final determination of their opening RAB for the 2025-30 regulatory period.

Ex-post review of Ergon Energy's capital expenditure from 2018 to 2023

Our ex-post review noted that although Ergon Energy needed to increase spending to control a trend in pole defects, their response was not reflective of prudent and efficient decision making.

In our decision we noted that Ergon Energy's governance and asset management practices didn't include root clause analysis to understand the underlying cause of the defects, nor did it include business cases and cost-benefit analysis to consider the most appropriate option for addressing the pole defects.

Further we noted that Ergon Energy's opportunistic repex related to its pole replacement program, which made up to 44.2% of the total overspend, was considerably more than is consistent when compared with good industry practice. This related to early replacement of larger assets like transformers and switchgears where there was no emerging safety risk.

Source: AER, Draft decision - Ergon Energy 2025-30 - Overview, September 2024, pp vii - viii.

In addition, our final determination for Ergon Energy's 2025-30 regulatory determination applied a CESS revenue adjustment (decrement) of -$566m.[16] This related to the application of the CESS in the 2020-25 regulatory period and the corresponding CESS carryover true-up for 2019-20.[17]

15 The amount of $599m was adjusted into June 2024 terms.

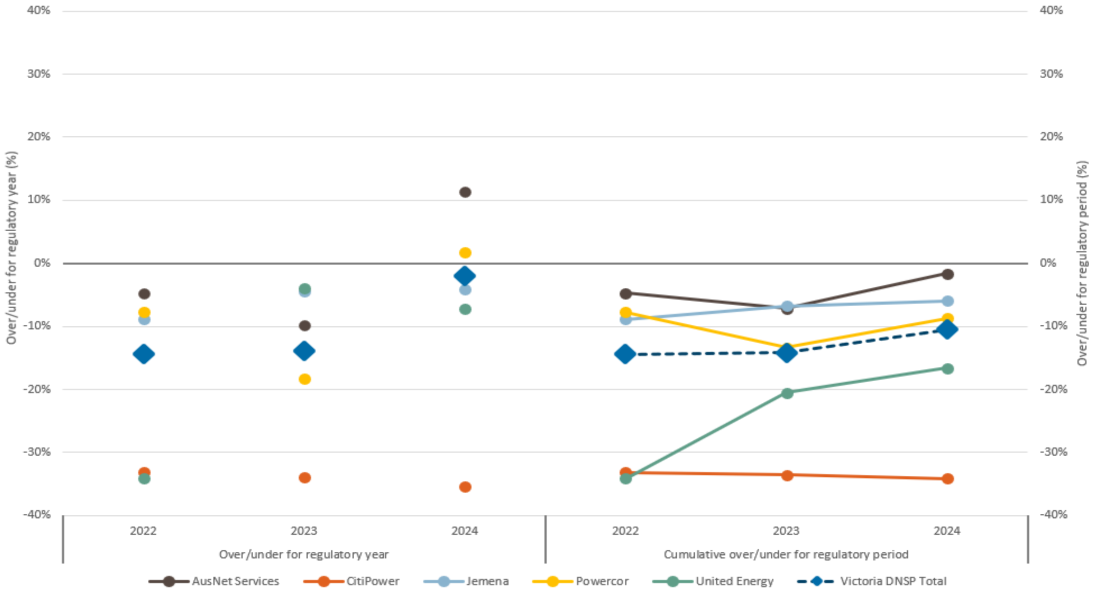
16 This has been converted in $ June 2024 dollar terms.

17 AER, Final decision – Ergon Energy 2025-30 regulatory determination, April 2025, p 27.

3.2.1.3 Victoria DNSP capex

In the first three years of their current 2021-26 regulatory period, Victorian DNSPs cumulatively underspent their capex allowance. The only overspends in the three-year period occurred in 2024, when AusNet Services and Powercor overspent their capex allowance.

Figure 3-10 Over/under spend of capex allowance for current regulatory period - Victorian DNSPs - $ real 2024



Source: Refer to actual and forecast capex for DNSPs from Figure 3-6.
Note: Refer to Figure 3-8.

The 2024 regulatory year is the third year of Victorian DNSPs' current regulatory period. Similar capex is forecast or estimated for Victorian DNSPs for the remaining two years (2025 and 2026).

The regulatory process for the Victorian DNSPs' 2026-31 regulatory period is currently underway with our final determinations due in April 2026. In the capex proposals, each Victorian DNSP except CitiPower proposed resilience capex for the 2026-31 regulatory period designed to reduce the risk and impact on consumers of power outages caused by severe weather events. A draft decision on resilience capex for Victorian DNSPs was made in September 2025, which approved $42m for AusNet Services,[18] $1m for Jemena,[19] $26m for Powercor[20] and $13m for United Energy[21] for their 2026-31 regulatory period.[22]

These expenditures relate in part to a recent rule change to establish a formal framework for distribution network resilience in the NER, which included new resilience expenditure factors. These new resilience expenditure factors may be taken into account by Victorian DNSPs in

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18 AER, AusNet Services 2026-31 Draft decision - Attachment 2 - Capital expenditure, September 2025, p 12.

19 AER, Jemena 2026-31 Draft decision – Attachment 2 – Capital expenditure, September 2025, p 9.

20 AER, Powercor 2026-31 Draft decision – Attachment 2 – Capital expenditure, September 2025, p 9.

21 AER, United Energy 2026-31 Draft decision – Attachment 2 – Capital expenditure, September 2025, p 8.

22 The approved resilience capex for AusNet Services, Jemena, Powercor and United Energy are in $ June 2026 terms.

their revised regulatory proposals, and the AER must take them into account for the 2026-31 regulatory period final determinations.[23]

AEMC rule change: Including distribution network resilience in the NER

In August 2024, the Victorian Minister for Energy, Environment and Climate Change submitted a rule change request to improve how distribution network resilience is accounted for in the current economic regulatory framework. The rule change request raised the following issues with the current regulatory framework:

- the lack of a formal framework for distribution network resilience creates regulatory uncertainty for DNSPs and the AER around how to efficiently spend on network resilience for prolonged power outages
- climate change and other hazards are expected to increase the likelihood of prolonged power outages, and the current regulatory arrangement places insufficient focus on consumer outcomes.

The proposal sought to include resilience in the NER in the form of DNSP expenditure factors for capex and opex and require the AER to publish formal guidelines on how it will assess DNSPs' proposals for expenditure on network resilience. [24]

The final rule made by AEMC in May 2025 addresses these issues, by establishing a formal framework for distribution network resilience, which includes:[25]

- new resilience expenditure factors that DNSPs and the AER would need to have regard to when proposing and assessing expenditure
- formal network resilience guidelines which the AER must develop, publish and maintain to meet a set of NER requirements, and new annual planning and reporting requirements for resilience. These guidelines must be finalised by 1 December 2026.

3.3 TNSP capex driven by investment in ISP projects

In the 2024 regulatory year, in contrast to DNSPs, TNSPs underspent their capex allowance by 23%, cumulatively investing $2.0b in transmission network assets. Over the last four regulatory years, TNSPs capex could be divided into its usual stay in business (SIB) capex[26] and capex in relation to ISP projects.[27]

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23 AEMC, Including distribution network resilience in the NER: rule determination, May 2025, p 11.

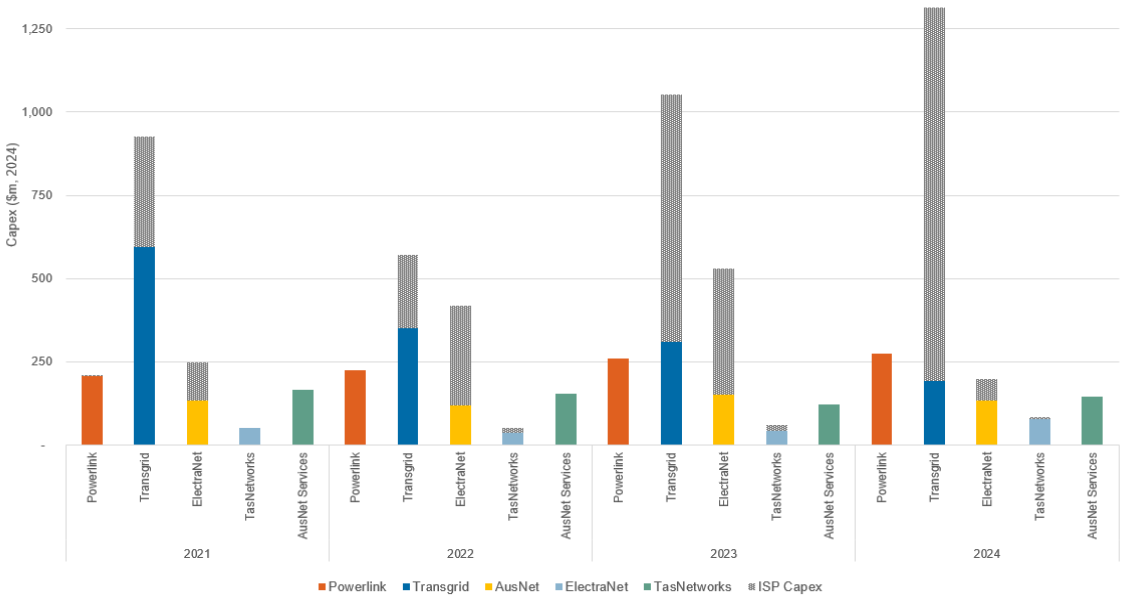
24 AEMC, Including distribution network resilience in the NER: consultation paper, October 2024, pi - ii.

25 AEMC, Including distribution network resilience in the NER: rule determination, May 2025, p 12.

26 SIB capex generally relates to capex invested by TNSPs to maintain their current transmission network assets. In this report, we have classified all non-ISP capex as SIB capex.

27 TNSPs started to invest into ISP projects in the 2019 regulatory year. There was $13m incurred in 2019 and $55m in 2020.

Figure 3-11 Capex and ISP Capex - TNSPs - $ real 2024



Source: Actual capex: RFM input - 'Actual capex,' 'Actual asset disposal,' 'Actual capital contributions.' Where RFM not available for TNSPs, use CA RIN: 2.1 Expenditure summary. ISP Capex sourced from information request.
Note: AER calculation to convert values into $ June 2024 terms. Net capex is gross capex less capital contributions and disposals.

In the last four regulatory years, 45% of TNSP capex has related to ISP projects, with "normal" SIB capex remaining relatively consistent. The majority of the ISP project expenditure has been incurred by ElectraNet and Transgrid.

3.3.1 Background of the ISP

AEMO's ISP provides a coordinated whole-of-system plan for efficient development of the power system in the NEM that achieves power system needs for a planning horizon of at least 20 years to contribute to achieving the NEO.

Through its ISP, AEMO identifies the combination of transmission network options (or equivalent non-network solutions) that in an optimal development path, that sets out the needed generation, firming and transmission through the electricity system's transition to a lower carbon future consistent with current policy settings. The optimal development path for AEMO's ISP includes a range of projects with different actionable frameworks.[28] These ISP projects are categorised as:

- committed and anticipated transmission projects already underway
- actionable projects, for which work should continue and/or commence urgently
- future projects, which may include the need for the TNSPs to undertake preparatory activities.

[28] Not all ISP projects are actionable under the ISP framework. ISP Projects in NSW may progress under the Electricity Infrastructure Investment Act 2020 (NSW), whilst Queensland ISP projects may progress under the Energy (Renewable Transformation and Jobs) Bill 2023 (Qld).

In August 2020 we published guidelines to make the ISP actionable .[29] This comprised the cost benefit analysis guidelines that describe the analysis that AEMO must apply in the ISP and TNSPs must apply in their Regulatory investment test for transmission (RIT-T) in an optimal development path, that sets out the needed generation, firming and transmission.[30]

In November 2024, the AER published an update to our guidelines, which includes the cost benefit analysis guidelines, RIT-T instrument and RIT-T application guidelines.[31]

3.3.2 TNSPs spent $1.2b on ISP projects in 2024

The actionable ISP projects where a trigger event under clause 5.16A.5 of the NER has occurred, and which we are considering or have made a decision on a contingent project application to amend a TNSP's determination under clause 6A.8.2 of the NER, are included in Table 3-3. Each project's actual capex investment, both in 2024 and in total, differs according to its progress.[32]

Table 3-3 Actionable ISP projects where we have made a contingent project decision[33]

Project and related TNSP	Description of project	Actual capex - 2024 ($m)	Actual capex - Total to date ($m)
HumeLink - Transgrid	A network upgrade to transmission lines to expand transmission capacity in southern NSW.	215	403
Project EnergyConnect (PEC) - Transgrid and ElectraNet	A new transmission line and interconnector between South Australia and NSW, together with a spur line linking to Victoria.	Transgrid - 745 ElectraNet - 48	Transgrid - 1,800 ElectraNet - 493
Eyre Peninsula Link - ElectraNet	A new transmission line between Cultana and Port Lincoln in South Australia	15	381
Project Marinus - TasNetworks	Comprises of Marinus Link, a 1500 MW transmission line between Tasmania and Victoria, and the North-west Transmission Development.	5	37

29 AER, Final decision - Guidelines to make the ISP actionable, August 2020.

30 The RIT-T instrument is a binding AER regulatory instrument published (originally in 2010) in accordance with NER clause 5.16.1(a). RIT-T proponents (usually TNSPs) must apply the RIT-T to all proposed transmission investments, except in the circumstances described in NER clause 5.16.3(a).

31 AER, Cost benefit analysis and RIT guidelines review - explanatory statement, November 2024.

32 All capex investment is reported in $ June 2024 terms.

33 This table only includes capex amounts for each project and therefore does not include any opex amounts incurred for each project.

Project and related TNSP	Description of project	Actual capex - 2024 ($m)	Actual capex - Total to date ($m)
Victoria to NSW Interconnector (VNI) West - Transgrid and TCV	A new 500 kV transmission line between Victoria and NSW, connecting the Western Renewables Link with PEC via a new terminal station.[34]	Transgrid - 69	Transgrid - 120
Waratah Super Battery (WSB) - Transgrid[35]	A battery project to increase power transfer capacity on transmission lines in the northern and southern regions of NSW to the Sydney, Newcastle and Wollongong region.	89	101

Source: Information requests to TNSPs and AER Analysis

All projects are actionable under the ISP framework, except for the WSB, which is actionable under the NSW framework.

34 This includes costs associated the Victoria-NSW transmission transfer capacity contingent project (VNI minor) which we have grouped into the larger VNI West project.

35 The capex amounts for 2024 and the total to date relate to non-contestable elements of the WSB project.

Waratah Super Battery

The WSB project is being delivered under the NSW Electricity Infrastructure Roadmap, which is enabled by the *Electricity Infrastructure Investment Act 2020*[36] and *Electricity Infrastructure Investment Regulation 2021*.[37] On 14 October 2022, the NSW Minister for Energy directed Transgrid as the Network Operator to carry out the WSB project.[38]

The project involves Transgrid contracting with a battery to provide a System Integrity Protection Scheme and 'paired generators' to operate in concert with the battery. Transgrid was required to deliver network augmentations and a control system to support the operation of the battery.

The Transgrid delivered components of the project were assessed under the non-contestable framework which is based on the national framework for regulation of transmission network businesses. We reviewed Transgrid's forecast costs to ensure only the prudent, efficient and reasonable costs of delivering the project are recovered by Transgrid.[39]

Our determination for the Transgrid delivered components allows $104.2 million ($nominal) of revenue to be recovered by Transgrid over the 2024-29 regulatory period.[40]

3.3.3 Investment required to deliver ISP projects lead to financeability concerns

TNSPs are in the early stages of completing their ISP projects. Our State of the energy market report noted that AEMO's 2024 ISP had $11.2b of committed and anticipated projects, $28.8b of actionable projects and $8.9b of future projects, for a total of $49.4b.[41] This is almost double the current RAB valuation of all TNSPs ($28b) and is a significant change from the normal incremental augmentation and stay in business replacement capex investment of NSPs.

NSPs invest into network assets using debt or equity, which typically results in cash outflows to either service the debt or pay dividends to equity holders.

The unprecedented capex investment required to deliver the ISP projects led Transgrid to raise issues with the regulatory framework, and the financeability of large-scale projects with long asset lives. These related to the deferment of revenue recovery from the indexation of the RAB and the return of capital (depreciation) building block being based on when the capital investment is commissioned rather than incurred.

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36 The AER is a regulator pursuant to this Act. One of our main functions is to determine the revenue a Network Operator may collect for undertaking a network infrastructure project. A Network Operator can be selected through a contestable and non-contestable process.

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38 NSW Government - EnergyCo, Waratah Super Battery Project, accessed 17 November 2025.

39 AER, Final Decision – Transgrid Waratah Super Battery 2024-29, December 2023, p 8.

40 AER, Final Decision, 2025-26 Adjustment – Transgrid Waratah Super Battery 2024-29, Appendix B – Quarterly Service Payments, May 2025, p 1.

41 AER, State of the energy market 2024, November 2024, p 118. Adjusted to $ June 2024 dollars.

Due to this, Transgrid made a rule change proposal for a participant derogation from the NER to remove these two regulatory concepts on Transgrid's share of the ISP projects which have yet to be determined through the contingent project process.[42]

The AEMC determined not to make the proposed participant derogation. The AEMC considered that the regulatory framework does not create a barrier for Transgrid to finance its share of the current ISP projects (including PEC). Further, the AEMC did not consider the proposed rule was the best option of providing the right incentives for Transgrid and other TNSPs to invest in the ISP, both currently and in the future.[43]

In their determination the AEMC noted that the rule change request and the submissions received, highlighted a broader set of potential issues relating to the current regulatory framework to support the timely and efficient delivery of large transmission projects. The scope of this review would include matters such as financing, regulatory and governance issues in the context of the overall regulatory framework for NSPs.[44]

In August 2021, the AEMC self-initiated a Transmission Planning and Investment Review (TPIR), to ensure the regulatory framework could accommodate the substantial investment in transmission infrastructure required for the ISP.[45]

3.3.3.1 Rule changes provide more financeability flexibility for ISP projects

The TPIR sought to:

- identify issues with the existing regulatory frameworks in relation to the timely and efficient delivery of major transmission projects
- explore options for reform or improvements to the existing regulatory frameworks
- recommend possible changes to the NER and other regulatory instruments (if required) to support frameworks that are fit-for-purpose and promote the timely and efficient delivery of transmission services.

In their final report (stage 2), the AEMC highlighted that successive ISP iterations could see major transmission works moved forward or bunched in a way that creates a financeability risk through pressures on cash flows and an NSP's credit metrics. The AEMC noted that the financeability concerns may arise from the way cash flow is impacted by major projects, as the cash flows from the return of capital building block may not reflect the financing requirements required for ISP projects.

Although the AEMC noted there was differing views on whether NSPs could adapt their capital structures through equity investment to meet finance investment requirements, they concluded that in practice NSPs may be constrained from doing so quickly. They noted that the constraints are more likely to be tested due to the size, scale and sequencing of ISP projects.

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42 AEMC, Participant derogation - Financeability of ISP projects: Rule change request, September 2020.

43 AEMC, Rule determination - Participation derogation - Financeability of ISP projects, April 2021, p i-ii.

44 AEMC, Rule determination - Participation derogation - Financeability of ISP projects, April 2021, p vi - vii.

45 AEMC, Transmission Planning and Investment Review, May 2023.

Based on this, the AEMC's final position was that the regulatory framework would benefit from more flexibility to address these financeability concerns. Their recommendation that the AER be given the explicit ability to vary the return of capital (depreciation) building block to address financeability challenges, where it considers it would better meet the NEO.

Accommodating financeability in the regulatory framework rule change

The final rule was made following the consolidation of two separate rule change requests. The first request was submitted by the Commonwealth Minister for Climate Change and Energy in April 2023 following the AEMC's TPIR final report recommendations.[46]

The second rule change request was submitted by ENA in June 2023. The request sought to ensure the financeability of actionable ISP projects, by seeking to maintain the AER's benchmark credit rating at the benchmark gearing level for each year of the relevant regulatory period.[47]

The final rule allows TNSPs to submit a financeability request to the AER as part of a contingent project application stage 2 for construction or as part of a revenue determination. This request can propose methods (i.e. adjustments to return of capital or revenue smoothing within a regulatory period) to the AER to address financeability issues.

The final rule requires the AER to:[48]

- assess whether the TNSP has a financeability issue by applying a financeability test set out in the NER, and if so, adjust a TNSP's cash flows
- set out further details of how it would determine the TNSP's financeability position in Financeability Guidelines. We published a final Financeability Guideline in November 2024.

Additional rules also apply to TNSPs that have already received concessional finance.

Source: AEMC, Accommodating financeability in the regulatory framework.

The rule change enables TNSPs to submit a financeability request as part of their contingent project application, which if approved, will change the network revenues they collect from customers. This change is expected to increase network costs for customers in the short term, possibly delinking customers payments from the benefits they receive from the infrastructure. However, this is balanced against ensuring that the regulatory framework is not impeding a TNSP's ability to efficiently raise finance and invest in ISP projects.

3.3.3.2 Rule change made to allow benefits of ISP low-cost finance are passed onto consumers

In June 2023, the Commonwealth Government allocated $19 billion to the Rewiring the Nation program to invest to modernise our electricity grid and deliver new and updated grid infrastructure. The program aims to make clean energy more accessible and affordable for Australian consumers. Investing occurs through the Clean Energy Finance Corporation

46 AEMC, Accommodating financeability in the regulatory framework: Consultation paper, June 2023, p 1.

47 AEMC, Accommodating financeability in the regulatory framework: ENA rule change request, June 2023.

48 AEMC, Accommodating financeability in the regulatory framework: Final determination, March 2024.

(CEFC), a “green bank,” whose investment function is to make complying investments, directly and indirectly, in clean energy technologies.

The CEFC‘s investment into priority transmission projects, such as those actionable under AEMO’s ISP, can provide TNSPs with low-cost or ‘concessional’ finance. Although beneficial to consumers by assisting in facilitating lower costs and/or facilitating faster delivery of ISP projects, it may also benefit TNSPs by lowering their debt costs.

Previously, the NER did not explicitly recognise the treatment of concessional finance, which raised an issue as to how the benefits from the Rewiring the Nation fund could be passed through to consumers. To address the issue, a rule change was made in March 2024 to enable the benefits to flow through to consumers.

Sharing concessional finance benefits with consumers rule change

The rule change request was initiated by a submission from the Commonwealth Minister for Climate Change and Energy in April 2023, after Energy Ministers endorsed a proposal that the Commonwealth submit a rule change request.[49]

The final rule introduced a mechanism in the regulatory framework that facilitates the sharing of concessional finance benefits with consumers. This allows the NSPs and a government funding body (i.e. the CEFC) to pass through an agreed amount to customers over an agreed period and/or or reduce the value of specified assets in the RAB.[50]

The final determination also applies additional rules to TNSPs that have received concessional finance, to ensure a TNSP does not benefit from both the concessional finance and cash flow adjustment to their ISP project.

Following this rule change, NSPs are required to provide the AER with an agreement signed by the government funding body setting out these agreed reductions and the timing of the reductions. The AER would also be able to consult with the relevant NSP and government funded body and request information needed to facilitate the sharing of benefits.

Source: AEMC, Sharing concessional finance benefits with consumers.

The two rule changes in March 2024, highlight how the regulatory framework has been adaptable, by changing to support the financeability of TNSPs in their delivery of the major investment projects and facilitating the sharing of low cost finance benefits with consumers.

In future years we plan to increase our reporting on ISP projects and expenditures to provide more information to stakeholders on the effectiveness of the regulatory framework in delivering the major investment projects required by the ISP.

49 AEMC, Sharing concessional finance benefits with consumers: Rule determination, p i, March 2024.

50 AEMC, Sharing concessional finance benefits with consumers: Rule determination - Information Sheet, March 2024.

3.4 Increased capex investment results in RAB growth

The RAB represents the total economic value of network assets that NSPs use to provide regulated network services. RAB values substantially impact the total network costs customers pay, both now and in the future, through the return on capital (a return to the investors that fund its assets and operations) and return of capital (asset depreciation costs) building blocks.

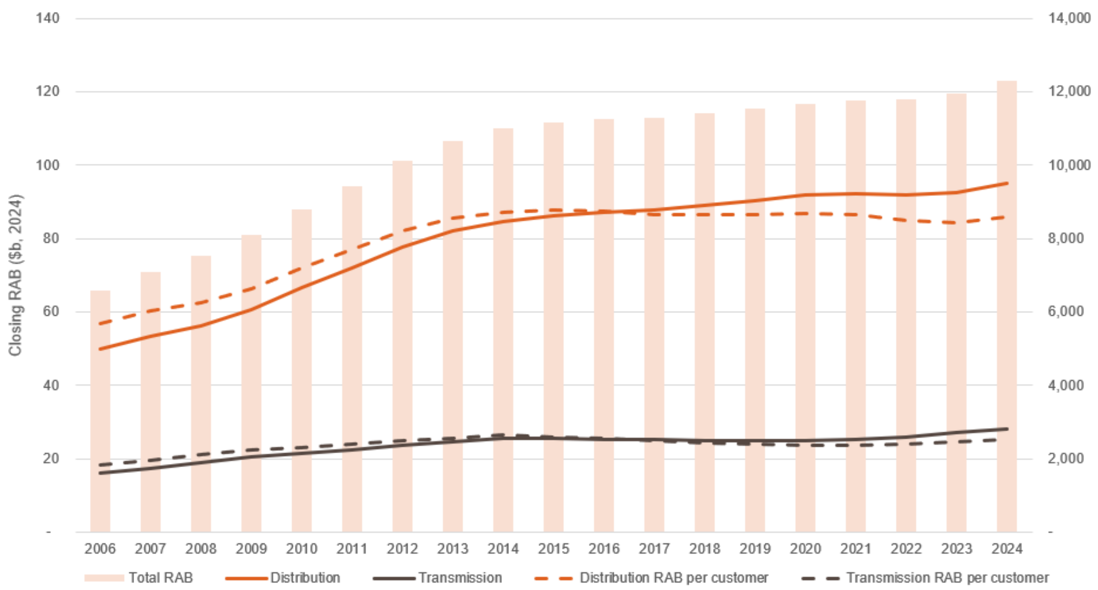
The average economic life of network assets varies across the NSPs, and the RAB is constantly changing as new assets replace aging and depreciated assets. This means some NSPs require significant capital investment for growth or replacement of their network assets, while others require less investment.

Recently we have been seeing capex proposals from electricity NSPs, which are consistently higher than approved by the AER in previous decisions. Higher capex investment for NSPs will likely result in higher RABs, as the capex is expected to exceed the future depreciation allowance.

In 2024, there was a 3.0% increase in NSPs RAB in real terms, with a combined value of $122.9b. Disaggregated there was:

- a 2.8% increase in real terms in the RABs of DNSPs for a combined value of $95.0b
- a 3.6% increase in real terms in the RABs of TNSPs for a combined value of $28.0b.

Figure 3-12 RAB - NSPs - $ real 2024



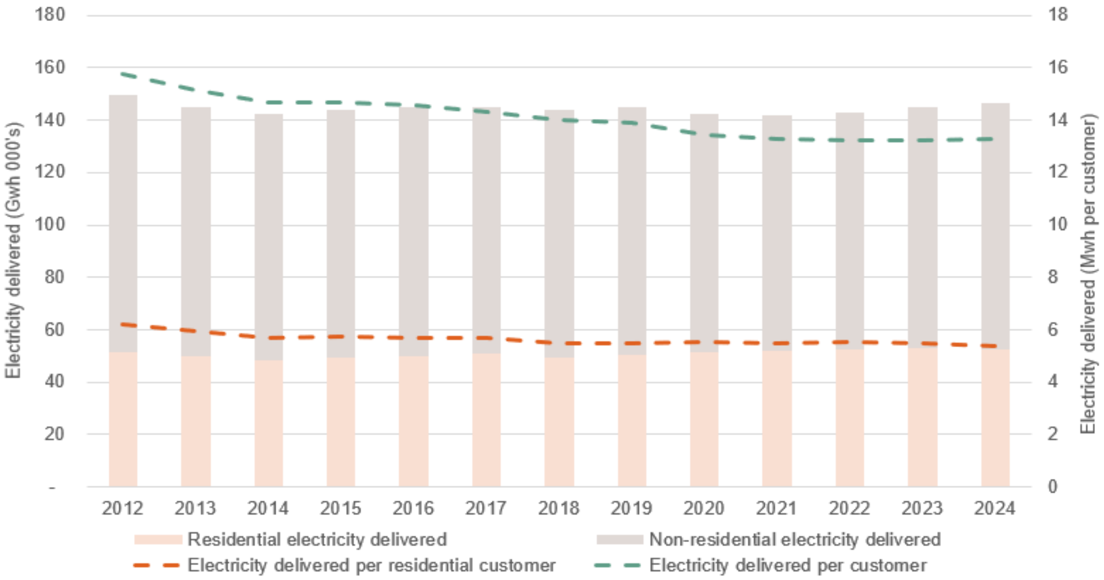
Source: Closing RAB: RFM, 'RAB roll-forward'. Customer numbers data is from EB RIN table 3.4.2, 'Distribution customer numbers by customer type or class.'
Note: AER calculation to convert to $ June 2024 terms. DNSP RAB per customer calculated by dividing DNSP's RAB by DNSP's customer numbers. TNSP RAB per customer calculated by dividing TNSP's RAB by the sum of distribution customers located in the same region as the TNSP.

The RAB per customer in 2024 was $8,587 for DNSPs (an increase of 1.8% in real terms) and $2,530 for TNSPs (an increase of 2.6% in real terms). This resulted in an overall increase of $215 in the RAB per customer in real terms in 2024 (an increase of 2.0%).

3.5 Electricity delivered increased, with further growth forecast

The electricity delivered differs across DNSPs, based on the composition and size of their customer base. Overall, DNSPs delivered 147,000 GWh of electricity in 2024, an increase of 1.4% on the previous year. This is the third consecutive annual increase, with the increase in 2024 largely driven by Endeavour Energy's medium-large customers, who accounted for most of the increase in 2024. Overall, the volume of non-residential electricity delivered increased (2%), whilst the residential electricity delivered decreased slightly (0.5%).

Figure 3-13 Electricity delivered - DNSPs

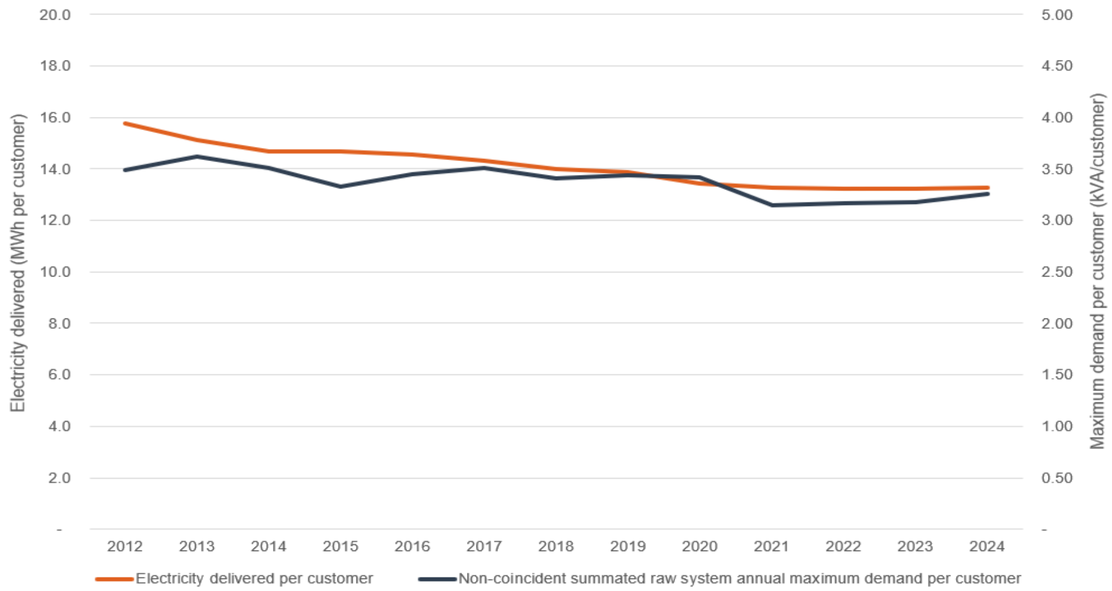


Source: Electricity delivered data is from EB RIN table 3.4.1, 'Energy delivered by type or class.' Customer numbers data is from EB RIN table 3.4.2, 'Distribution customer numbers by customer type or class.'
Note: Electricity delivered per customer and residential customer calculated by dividing total of electricity delivered by total customer numbers and residential customers respectively.

In 2024 residential consumption per customer decreased slightly. Since 2012, residential consumption per customer has been relatively consistent as increased consumption from a growing customer base and the electrification of household gas appliances has been offset by lower consumption from improved appliance efficiency and use of CER, such as rooftop solar and batteries.

The trend of decreasing consumption on a per customer basis is also apparent in the maximum demand per customer, though this metric has been rising since 2021, and again rose in 2024.

Figure 3-14 Electricity delivered and maximum demand



Source: Electricity delivered data is from EB RIN table 3.4.1, 'Energy delivered by type or class.' Customer numbers data is from EB RIN table 3.4.2, 'Distribution customer numbers by customer type or class.' Non-coincident summated raw system annual maximum demand' from EB RIN table 3.4.3.3 - 'Annual system maximum demand characteristics as the ZSS level' MVA measure.
Note: Electricity delivered per customer and residential customer calculated by dividing total of electricity delivered by total customer numbers and residential customers respectively.

Going forward, based on the step change scenario in AEMO's 2025 Inputs, assumptions and scenarios report we expect increased consumption from a growing customer base, residential customers switching their household heating and cooking appliances from gas to electric and replacing internal combustion engines with electric vehicles.[51] This consumption will be offset by improvements in appliance efficiency and residential customers continuing to invest into CER technologies.

There is uncertainty on how these factors will impact the maximum demand for DNSPs both on an overall and customer basis, and whether recent rising trend in 2024 is continued in future regulatory years. In future reports, we will continue to analyse whether increased consumption is reflected in higher maximum demand, including how this is differing across the electricity DNSPs

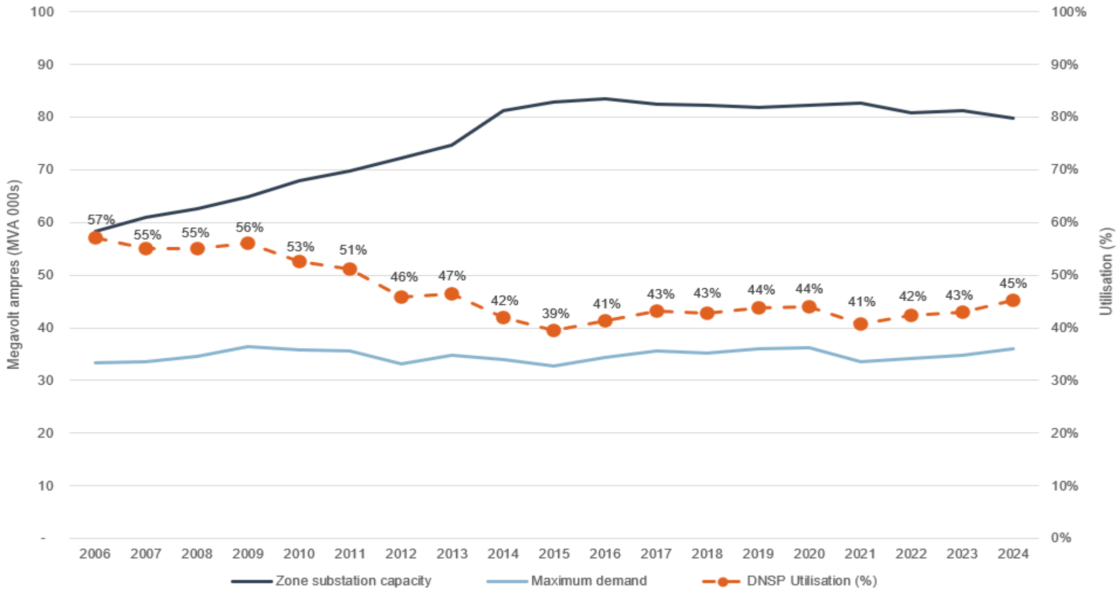
3.6 Utilisation increased slightly but remained consistent with prior years

Network utilisation is important, as it can measure the productivity and efficiency of network assets to determine whether customers are paying the lowest cost possible for network services. Our current network utilisation performance data measures the extent to which an NSPs network assets can meet the maximum demand in their network. We calculate

[51] AEMO, 2025 Inputs, Assumptions and Scenarios Report, August 2025, p 7.

utilisation by dividing a DNSP's non-coincident maximum demand by the total capacity of its zone substation (ZSS) transformers.[52]

Figure 3-15 Network utilisation - DNSPs

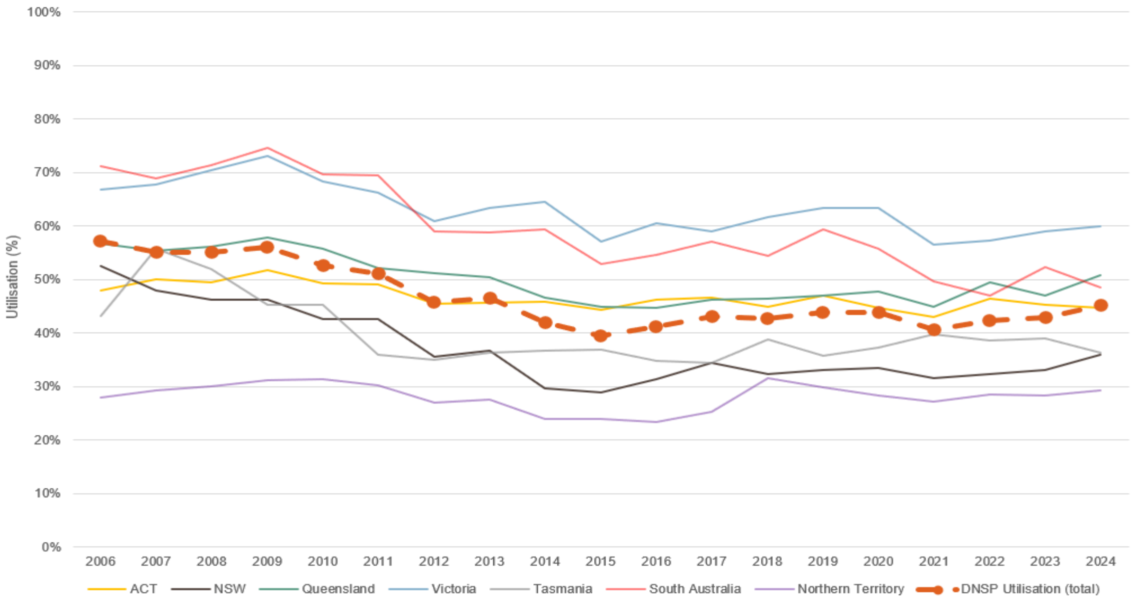


Source: Non-coincident summated raw system annual maximum demand' from EB RIN table 3.4.3.3 - 'Annual system maximum demand characteristics as the ZSS level' MVA measure. 'ZSS transformer capacity' from EB RIN table 3.5.2.2.
Note: System capacity utilisation calculated by dividing the DNSP's non-coincident summated raw system annual maximum demand by the DNSP's ZSS transformer capacity.

The ZSS transformer capacity, maximum demand and utilisation have all been relatively flat since 2014, although there has been a slight decrease in capacity in 2024 and a slight increase in maximum demand which has led to higher network utilisation in 2024.

52 The individual maximum demand on an DNSP's network for the regulatory year

Figure 3-16 Network utilisation - DNSPs by jurisdiction



Source: Refer to Figure 3-15 Figure 3-15.
Note: Network utilisation by jurisdiction calculated by dividing the sum of the jurisdiction's DNSP's non-coincident summated raw system annual maximum demand by the sum of the jurisdiction's DNSP's ZSS transformer capacity.

Network utilisation differs across DNSPs and jurisdictions. Powercor has consistently had the highest network utilisation measures whilst Essential Energy has the lowest. Lower utilisation for DNSPs in NSW and Queensland can be attributable to changes in jurisdictional reliability standards and forecast demand growth, which led to systematic capital investment in ZSS transformer capacity from 2009 to 2014.

3.6.1 Low voltage visibility will provide more information to stakeholders

Our current network utilisation measure is an informative but incomplete measure of whether a network can deal with network congestion or peak demand at a localised or overall level. These issues are being exacerbated by:

- the expected increase in energy delivered and peak demand from customers switching their household heating and cooking appliances from gas to electric and anticipated acceleration in the uptake of electric vehicles
- the increase in DER (including CER), as electricity being exported into the electricity grid can lead to localised network congestion which may need capital investment to alleviate.

With CER increasing, managing the changing demand-supply balance in localised low voltage networks is becoming increasingly challenging. Currently, there is a lack of visibility to stakeholders on how DNSPs are utilising their network assets to facilitate and optimise CER, whilst managing peak demand with network. The availability of data could assist a number of stakeholders especially customers investing into CER, consumer groups and policy makers to effectively plan and optimise the benefits of CER.

The visibility of this data was investigated as part of our low voltage visibility work program. Low voltage visibility plays a crucial role in relation to the facilitation and optimisation of DER and empowers non-network participants of all kinds to understand, interact, invest and connect with distribution networks.

In 2023, the Energy Security Board (ESB) Data Strategy tasked the AER to improve third party access to network data through the Low-voltage Network Visibility project.[53] In March 2025 we published our Phase 3 low-voltage network visibility report to identify the actions we will take to ensure distribution networks are transparently providing information to key stakeholders and the public.

Phase 3 low-voltage network visibility report – Summary of actions

The report outlines the following actions to ensure there is adequate visibility of distribution network data to third parties.

- We will support changing the NER to ensure DNSPs publish key information that they possess. This involves supporting key elements of the Integrated Distribution System Planning rule change, recently submitted by the AEMC by Energy Consumers Australia. This will improve DNSP planning processes, increase the amount of data collected and published by DNSPs and make it easier for third parties to understand the costs and benefits of DER investments connected to distribution networks.
- We will publish network performance metrics as reputational incentives for DNSPs to facilitate the connection of DER. This occurs through our Export services network performance reporting, which in 2025 will report on electric vehicles, electric vehicle chargers and community-scale batteries. Reporting on these types of metrics can provide reputational incentives and influence DNSP behaviour.
- We will investigate if new incentive arrangements are needed to align DNSP actions with consumer outcomes. This involves reviewing incentive arrangements, including our existing incentive schemes, guidelines and benchmarking models. Further we will seek to ensure that incentive arrangements are appropriate so that DNSPs are encouraged to provide available network capacity to potential customers, before building new network infrastructure. We will commence this review in 2026.
- We will encourage innovation in data sharing within the regulatory framework through policy-led sandboxing. The AER administers the Energy Innovation Toolkit, which supports energy innovators in trialling new products and services that will benefit consumers. Trial waivers can exempt innovators from having to comply with specified energy laws and rules for a specific period of time. In the report, we note we will treat trial waiver proposals favourably where they demonstrate enhanced benefits associated with the public sharing of network data and information.

Source: AER, Low-voltage Network visibility – Phase 3 Final Report, March 2025.

The Phase 3 low-voltage network visibility report notes that there are challenges to implementing network visibility, as data requirements can change, and there are costs associated with DNSPs providing more network visibility. As provided in the report, we will

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53 ESB, Data Strategy, accessed 4 November 2025.

work stakeholders to overcome these challenges to implement network visibility measures where they are cost beneficial to consumers.

3.7 Reliability for electricity DNSPs remains steady

Supply reliability is a key network service outcome. We measure reliability based on the frequency and duration of interruptions to customer supply. Our reporting is based on normalised measures of network interruptions, which do not include supply interruptions that are not reasonably within the control of NSPs, such as those caused by natural disasters, or interruptions which occur due to planned maintenance. This includes reporting on:

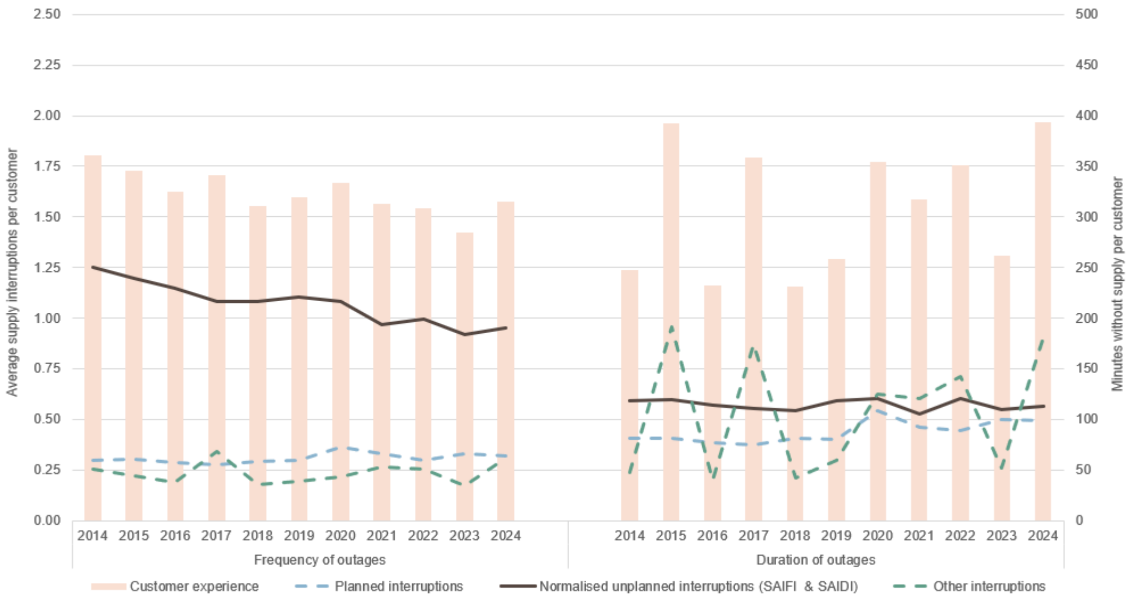
- system average interruption frequency index (SAIFI), which measures the average number of interruptions each year outside of excluded events
- system average interruption duration index (SAIDI), which measures the average duration (in minutes) of interruptions each year outside of excluded events.

Networks are incentivised to decrease SAIFI and SAIDI through the STPIS (see above). The STPIS incentivises networks to improve reliability where the value of the extra reliability to customers exceeds the capex or opex costs of providing the improved reliability.

When including all outages, in 2024 the average DNSP customer experienced 1.6 outages, for a total time without supply of 394 minutes. When normalised, the average DNSP customer experienced 1.0 outages, for a total time without supply of 115 minutes. When compared to 2023, there was a slight increase in both metrics on a normalised basis due to a higher frequency and longer duration of other (unplanned) outages.

Outages are highest for rural networks that are large with low customer density, while they are lowest for urban and CBD networks.

Figure 3-17 Frequency and duration of outages - DNSPs



Source: CA 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 regulatory years.

3.8 Rule changes to expedite smart meter rollout

Since 2017, coordinating and installing type 4 or type 4A meters[54] (smart meters) outside of Victoria was not the responsibility of the electricity DNSPs. Therefore, smart meter penetration should not be inferred as network performance, however the rollout of smart meters will improve network visibility, as it will provide more information to both electricity DNSPs and customers.

Our 2024 report noted that the AEMC had completed a review into the regulatory framework for metering services, and that a rule change process was underway to give effect to the recommendations made.[55] In November 2024, these recommendations were implemented following the AEMC publishing a final determination and final rules for the Accelerating smart meter deployment rule change project. These final rules enable the universal uptake of smart meters in the NEM by 2030.[56]

This rule change is being progressively implemented into the NER, with the rules in relation to the Legacy Meter Replacement Plan (LMRP) commencing in December 2024. This requires each electricity DNSP to develop a 5-year LMRP to schedule the replacement of legacy meters (type 5 and 6, excluding type 5 meters that are capable of remote acquisition) by 30 November 2030, with yearly interim targets.[57] Although DNSPs were required to submit their LMRP to the AER for approval in June 2025, the impact of this rule change will not be evident in the smart meter performance data in the 2025 regulatory year.

The installation of smart meters is an important part of the energy transition. The AEMC noted that a higher uptake of smart meters should enable a range of potential options that better integrate CER into the energy system and allow consumers to choose from different access and pricing services that best meet their needs and preferences. However, as stated by the AEMC, these benefits will rely on a minimum uptake of smart meters.[58]

3.8.1 Progress on smart meter installations

We report ‘smart meters’ as the sum of the Type 4 and Type 5 meters reported by DNSPs. These do not include accumulation meters, which are still a significant portion of the meters used outside Victoria.[59]

Accumulation meters are ‘count up’ meters which measure how much energy is consumed over a period, but not the time of day the consumption occurred. Smart meter installations are currently triggered by upgrades from single to 3 phase connections, solar PV

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54 Type 4A meters are smart meters with remote access functions and capabilities disabled.

55 AER, Electricity and gas networks performance report 2024, September 2024, p 46.

56 AEMC, Final determination - Accelerating smart meter deployment, November 2024, p ii.

57 AEMC, Accelerating smart meter deployment, November 2024, accessed 17 March 2025.

58 AEMC, Final report: Review of the regulatory framework for metering services, August 2023, pp ii-iii.

59 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.

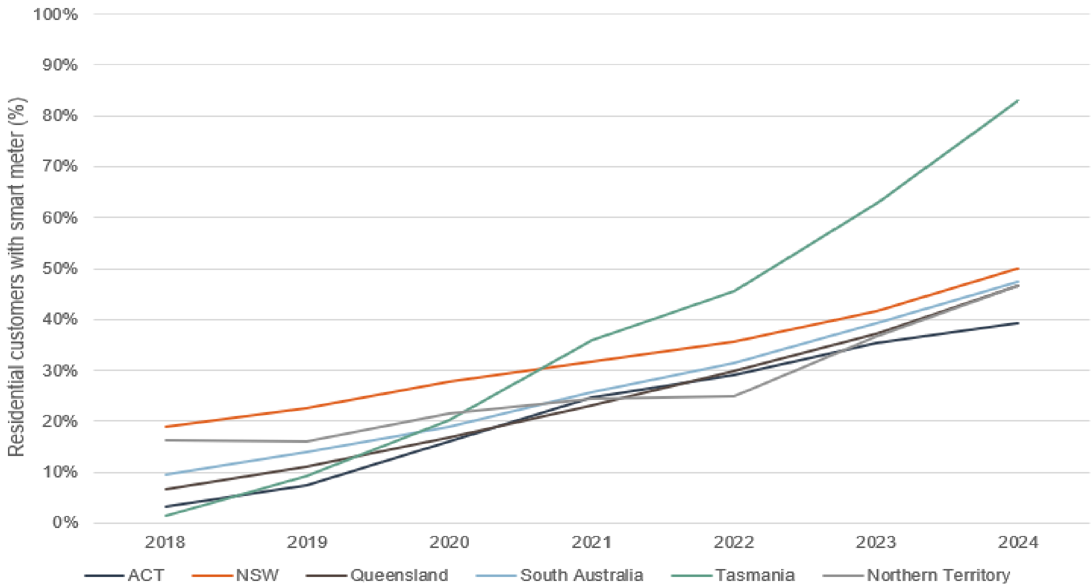
installations, replacements of old accumulation meters and new connections. Type 5 meters are more limited than type 4 meters only allowing time of use pricing.[60]

The penetration of smart meters is different amongst jurisdictions and customer types. The proportion of customers on smart meters also varies between electricity distribution networks within jurisdictions, with this information also provided in our operational performance data published alongside this report.

We have excluded Victorian smart meter installations from our analysis. This is due to Victorian electricity DNSPs effectively completing their smart meter rollout in 2015,[61] with on average 99.7% of residential customers with a smart meter and 97.9% of non-residential (low voltage) customers having a smart meter.

In 2024, Tasmania had the highest installation of smart meters for residential customers, with the state government committed to completing their smart meter rollout by the end of 2026.[62] The next highest jurisdiction was NSW, with the other jurisdictions ranging from approximately 40% to 47% of smart meter installations for residential customers.

Figure 3-18 Residential customers with a smart meter - 2024



Source: Residential smart meters: Annual RIN, ‘Table P1.1 - Distribution customers numbers by meter type’ - Residential - Type 4 and 5 meters.
Note: Proportion of smart meters installations for residential customers calculated by dividing the Residential smart meters by the total number of residential meters.

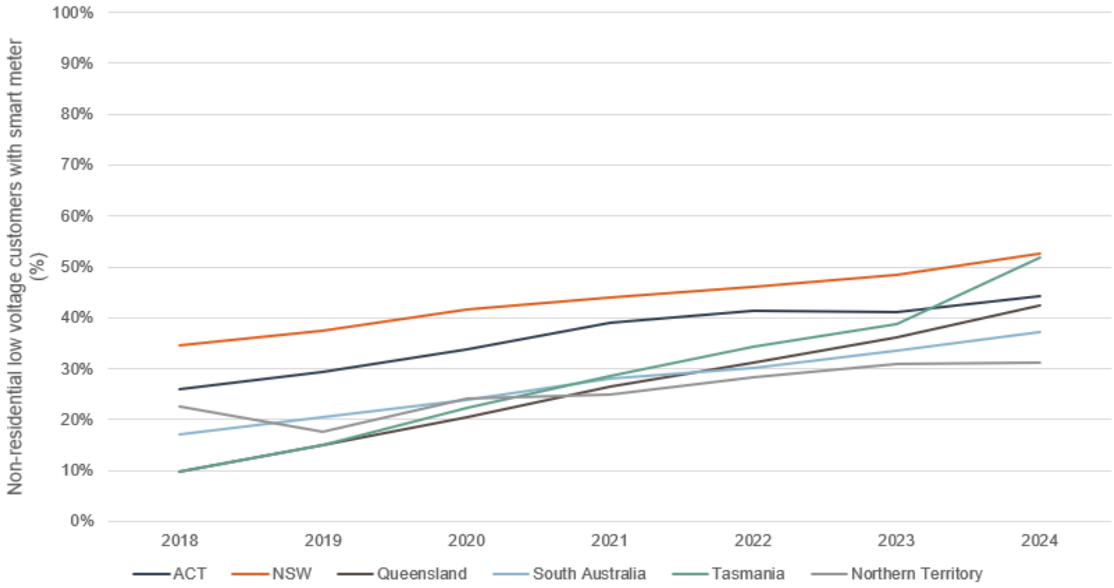
For non-residential low voltage customers, NSW and Tasmania had approximately the same proportion of smart meters installed, leading the other jurisdictions.

60 Although considered ‘smart meters’, some type 5 meters outside Victoria with no remote reading capabilities are being replaced as part of the AEMC’s recommendations for the rollout of smart meters.

61 Victorian Auditors General Office, Realising the Benefits of Smart Meters, September 2015.

62 Premier of Tasmania, Tasmania's smart meter rollout ahead of the curve, September 2024.

Figure 3-19 Non-residential (low voltage) customers with a smart meter - 2024



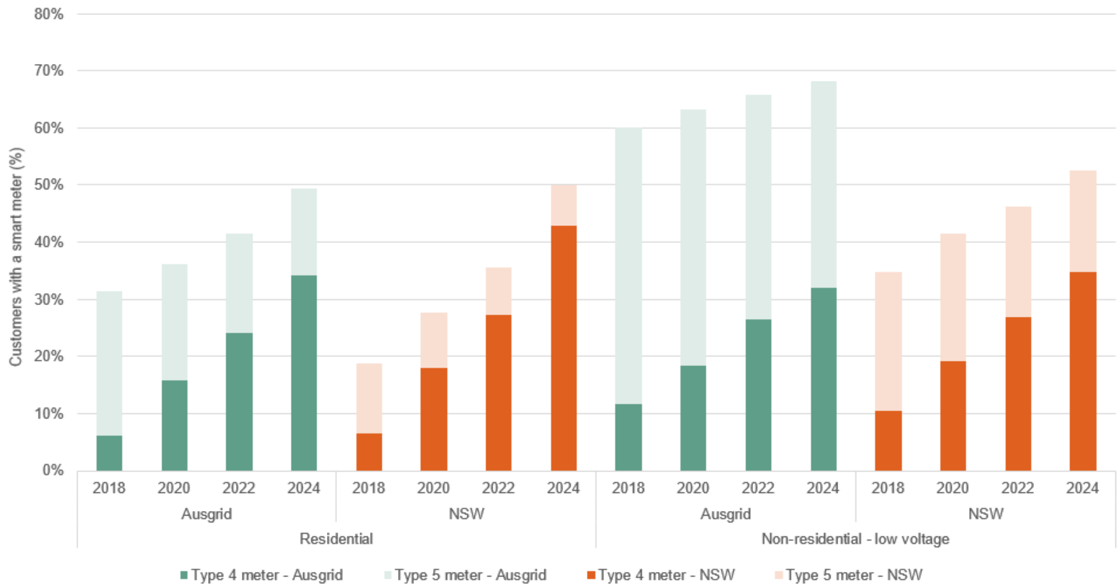
Source: Non-residential (low voltage) smart meters: Annual RIN, 'Table P1.1 - Distribution customers numbers by meter type' - non-residential - low voltage - Type 4 and 5 meters.
Note: Proportion of smart meters installations for non-residential (low voltage) customers calculated by dividing the non-residential - low voltage smart meters by the total number of non-residential - low voltage meters.

3.8.2 Smart meter replacement progress in Ausgrid's distribution network is slower due to inclusion of type 5 meters

Type 5 meters have time of use capabilities, so our reporting includes them with type 4 'smart meters'. The majority of non-Victorian type 5 meters are in the Ausgrid distribution network, and these meters are being replaced as part of the AEMC's recommendations for the rollout of smart meters.

Consequently, the smart meters installation progress for Ausgrid and the NSW jurisdiction, is lower than reported in the headline numbers. When only including type 4 meters, residential and non-residential low voltage smart meters in Ausgrid's distribution network are only marginally above 30% of all meters. When considering only type 4 meters for the NSW jurisdiction, the rollout for residential customers is similar to the progress in Queensland and South Australia.

Figure 3-20 Ausgrid - type 4 and 5 meters



Source: Residential and non-residential smart meters: Annual RIN, 'Table P1.1 - Distribution customers numbers by meter type' - Residential and Non-residential - Type 4 and 5 meters. Note: Proportion of smart meters installations for residential and non-residential customers calculated by dividing the residential and non-residential smart meters by the total number of residential and non-residential meters.

Despite slower progress in the overall smart meter rollout, the replacement of type 5 meters in Ausgrid's distribution network with type 4 meters is advancing. In the 7-year period, 37% of type 5 residential meters and 23% of type 5 non-residential low voltage meters (Figure 3-20) have been replaced in Ausgrid's distribution network.

3.9 Customers on cost reflective network tariffs increases

Network tariffs allow DNSPs to recover revenue to build, operate and maintain the network that is used to transport electricity. DNSPs charge network tariffs to retailers who then package the costs up as part of their retail tariffs to pass on to their customers. In addition to distribution network charges, a DNSP's network tariff also recover costs associated with pass-through transmission and jurisdictional scheme charges.

Since November 2014, DNSPs have been required under the rules to gradually implement tariffs that are more reflective of the efficient costs (or long run marginal cost) of providing distribution services to consumers. The program of network tariff reform aims to encourage higher network utilisation and more efficient use of a network's existing capacity, which may minimise the significant future capex investment to meet the consumption and demand from increased electrification in the energy transition.[63] It will also allow the efficient grid integration of CER such as solar PV, batteries and electric vehicles.

63 AER, Network tariff reform

Retail tariff charging components

Retail tariffs charged to customers usually consist of a fixed access or supply charge component, and one or more components for the electricity consumed. Electricity consumption may be charged at a flat rate where charges are based on anytime consumption or at a (more cost reflective) variable rate where the charges are based on time of use and/or demand:

- **Anytime consumption** charges are based on the amount of electricity consumed during a billing period, irrespective of the time of day or day of the week it is consumed.
- **Time of use (ToU)** charges are based on the amount of electricity consumed during a specific period of time, for example from 4pm to 9pm on a weekday.
- **Electricity demand** charges are based on the amount of electricity consumed at a specified point in time.

Cost reflective network tariffs can help to achieve efficient integration by encouraging and rewarding consumption when there is abundant network capacity (and encouraging and rewarding exports when network capacity is low). However, realising the full value of network tariff reform requires tariff design, effective consumer acceptance and response and coordination with planning and investment decisions. This is particularly important as the energy transition continues, electrification increases, new technologies are taken up, and energy use patterns change.

Cost reflective network tariffs contrast with flat network tariffs which are agnostic to when consumption occurs. Charging the cost reflective network tariffs to a customer's retailer, creates price signals that expose the retailer to the higher costs of network congestion or periods of peak demand.

This exposure is designed to incentivise retailers to take actions that reduce network congestion. Action may include retail offers with differing prices in different periods to encourage customers who are willing and able to reduce or shift their energy consumption. Incentives may involve retailers charging higher rates for network use during peak demand periods (while rewarding CER exports) and lower rates during off-peak periods (while discouraging CER exports). By minimising the potential capex investment and the associated maintenance costs of resulting network assets, DNSPs can lower network costs for all customers.

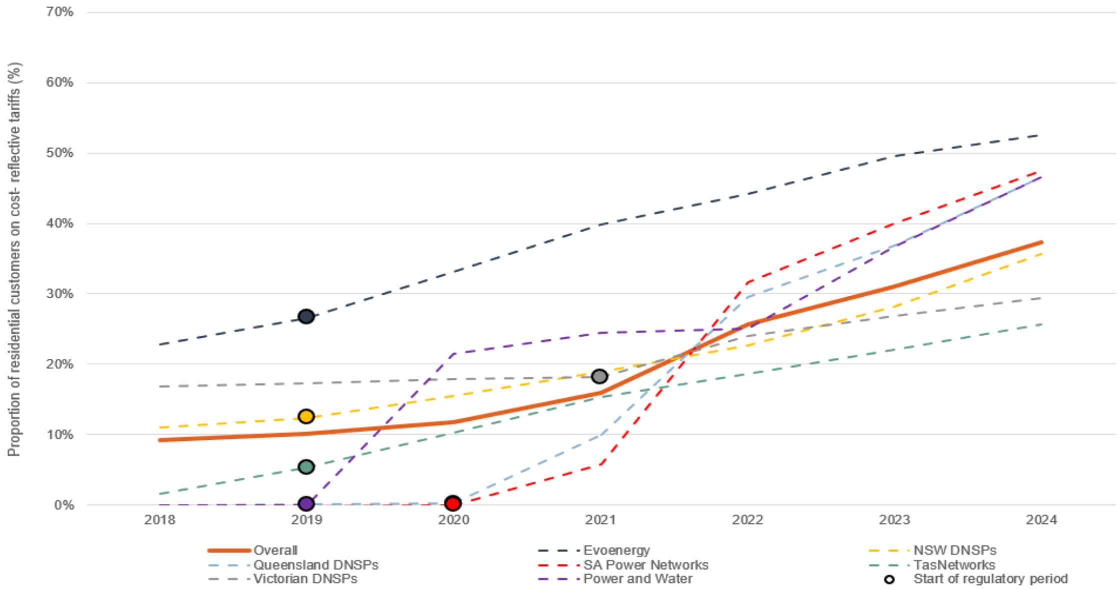
3.9.1 Residential customers on cost reflective network tariffs increased, but not uniformly

DNSPs assign network tariffs to each connection point, in accordance with the tariff assignment policy outlined in their tariff structure statement (TSS). Each DNSP's TSS needs AER approval every 5 years, alongside the DNSP's broader revenue proposal. The TSS sets out the DNSP's proposed tariffs, including a tariff assignment policy and how they are progressing tariff reform by making their tariffs more cost reflective.

Historically this has resulted in an uptick in the proportion of residential customers on cost reflective network tariffs following the start of the regulatory period. This is due to the "bulk" reassignment of customers to cost reflective network tariffs, as the reassignment policies have progressively shifted from opt-in, to opt-out and now to (mostly) mandatory.

This impact of the tariff reassignment is evident in Figure 3-21 for SA Power Networks, the Queensland DNSPs and Power and Water Corporation, which shows step changes at points in time when assignment policies changed. These DNSP's now have almost half their residential customers on cost reflective network tariffs after having practically no customers on these tariffs at the start of their last regulatory period.

Figure 3-21 Proportion of residential customers on cost reflective network tariffs



Source: Residential cost reflective tariffs: Annual RIN, 'Table P1.3A - NMI Count - by tariff type' - Sum of cost reflective tariffs.
Note: Proportion of cost reflective tariffs for residential customers calculated by dividing the sum of residential cost reflective tariffs by the total residential cost reflective and non-cost reflective tariffs.

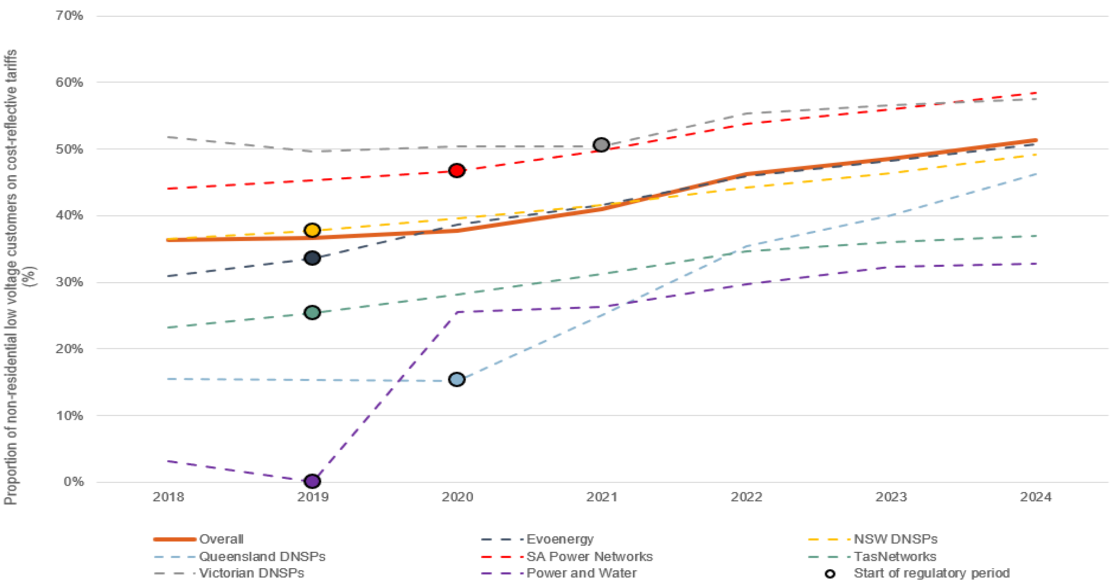
This contrasts with the Victorian DNSPs who have had an average annual 2 percentage point increase of residential customers on cost reflective network tariffs over the 7-year period.

Victoria's low adoption of cost reflective network tariffs is primarily due to assignment policies, in combination with its early smart meter rollout being practically completed in 2015. Similar to other DNSPs, Victorian DNSPs' assignment to cost reflective network tariffs was initially opt-in.

While policies have since become opt-out, Victoria's pre-existing full smart meter rollout has meant there are few triggers for reassignment to cost reflective network tariffs, so for many customers it remains in-effect opt-in. The current opt-out policies align with a Victorian Government Order in Council,[64] which doesn't allow mandatory reassignment to cost reflective network tariffs.

64 Electricity Industry (Victoria) Act 2005, Advanced Metering Infrastructure (Retail and Network tariffs) Order in Council, Victorian Government Gazette, S 295, 16 June 2021.

Figure 3-22 Proportion of non-residential low-voltage customers on cost reflective network tariffs



Source: Non-residential low voltage cost reflective tariffs: Annual RIN, 'Table P1.3B - NMI Count - by tariff type' - Sum of cost reflective tariffs. Note: Proportion of cost reflective tariffs for non-residential low voltage customers calculated by dividing the sum of non-residential low voltage cost reflective tariffs by the total non-residential low voltage cost reflective and non-cost reflective tariffs.

The number of non-residential low voltage customers (small and larger businesses) on cost reflective network tariffs is relatively consistent with last year, marginally increasing to more than half of all customers on cost reflective network tariffs.

3.9.2 Cost reflective network tariffs provided more pricing options to customers

An illustration of cost reflective tariffs rewarding consumption when there is abundant network capacity is through 'solar soak' tariff components. These components incentivise retailers to take actions to encourage customers to shift their electricity consumption to periods when locally generated electricity from CER is available and overall demand is relatively low, which often occurs during the middle of the day. SA Power Networks was the first DNSP to include a residential ToU network tariff with a low cost 'solar soak' period during the middle of the day for their 2020-25 regulatory control period.[65] It is now a nationwide trend, for example, with each Victorian DNSPs' TSS proposals for the 2026-31 regulatory period, proposing a version of a low cost 'solar soak period' from 11am to 4pm in their residential ToU network tariffs.[66]

Solar soak charges enable some non-CER customers to benefit from CER, while helping to mitigate the impact of minimum system demand events. By incentivising consumption during periods of energy abundance and network capacity, solar soak charges also facilitate more

65 AER, SAPN - Revised regulatory proposal - Attachment 17 - TSS Part B - Explanatory Statement, December 2019, pp 56-57.

66 AER, ASD - AusNet - TSS Compliance document, January 2025, p 4; CitiPower TSS 2026-31 - Compliance Document, January 2025, p 11; JEN - Att 09-01 TSS, January 2025, p 12. Powercor and United Energy's TSS 2026-31 compliance document used the same wording as CitiPower.

CER-driven energy being hosted on distribution networks, with lower generation costs and commensurate emissions reduction benefits.

The solar soak period is an example of how customers who can shift their consumption can use cost reflective tariffs to possibly lower their retail bill, and at the same time contribute to broader system and environmental benefits. In contrast, under a flat price tariff, customers only have one option to decrease their energy costs; use less energy. Through ToU pricing, retailers and their customers have more opportunities to lower their retail bill.

3.9.3 Tariff trials enabled DNSPs to innovate and test how customers respond

Tariff trials provide an opportunity for DNSPs to collaborate with electricity retailers, to explore complex and innovative tariffs and see how customers respond to different price signals and incentives. To date, DNSPs have submitted 38 tariff trial notifications to the AER, many of which incorporate multiple individual trial projects, with the pace of innovation increasing. We are seeing new tariff structures move from the concept stage to innovative trials to incorporation in approved TSSs.

As one example, in 2024, SA Power Networks concluded a tariff trial known as ‘Residential Electrify’ which enabled customers to opt into two residential versions of the trial tariff.[67]

Both versions of the tariff included a solar soak period from 10am to 4pm each day. This was designed for customers with CER, and/or household appliances with sufficient flexibility to use electricity outside peak demand periods. One version of the trial tariff also included export reward charges for customers able to export electricity.[68]

On conclusion of the trial, SA Power Networks found that 71% of solar customers and 80% of non-solar customers saved money from increasing daytime consumption and reducing energy consumption in peak demand periods.[69] This is a case study that demonstrates that when customers who can shift flexible loads are made aware of how to respond to price signals, they can benefit from cost reflective tariffs.

SA Power Networks TSS for the 2025-30 regulatory period, approved by the AER in April 2025, includes tariffs based on those trial tariffs.

3.9.4 Comparison of smart meters to cost reflective tariffs

To access the benefits of cost reflective tariffs, customers must have their accumulation meter replaced with a smart meter. As noted above, tariff assignment policies have enabled most DNSPs to reassign customers to cost reflective network tariffs following the installation of their smart meter (typically with a 12 month lag or transition tariff before reassignment).

A comparison of smart meter installations to the take-up of cost reflective network tariffs is an important metric. As mentioned above, these tariffs create price signals to incentivise retailers to take actions to reduce network congestion. This may include retailers offering

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67 SA Power Networks, Trial Tariffs 2024-25, August 2024.

68 SA Power Networks, Trial Tariffs 2024-25, August 2024, pp 4, 5-7.

69 AER, SAPN - 5.7.15 - CER Integration Strategy - January 2024, p. 11

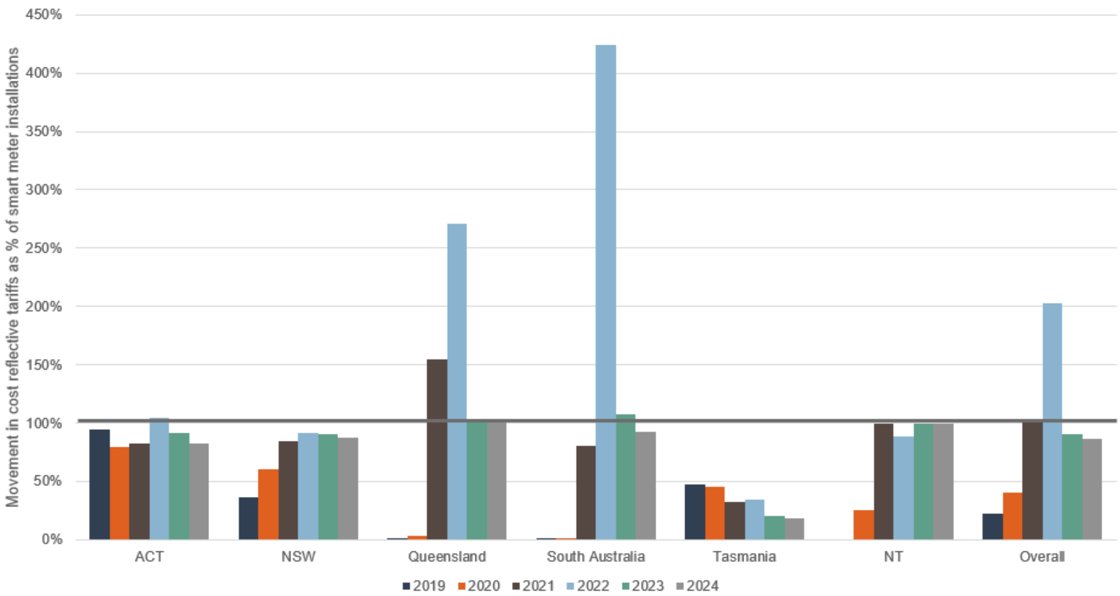
cost reflective retail tariffs, which have different prices in different periods to encourage customers who are willing and able to reduce or shift their energy consumption.

3.9.4.1 Tariff reassignment moves residential customers to cost reflective network tariffs

The comparison of residential smart meter installation and a customer on a cost reflective network tariff, differs across the jurisdictions and is largely based on tariff reassignment policies. Since 2021, in ACT, NSW and NT a smart meter installation has largely resulted in residential customers being on a cost reflective network tariff.

Similar findings were also apparent in Queensland and South Australia for all years except 2022 (and 2021 in Queensland) where there was a significant increase in residential customers on cost reflective network tariffs. This is due to the tariff assignment policy for Queensland and South Australian DNSPs, which allowed the DNSPs to reassign customers with a smart meter installed to a cost reflective network tariff.[70]

Figure 3-23 Residential cost reflective network tariff movement compared to smart meter installations - non-Victorian jurisdictions



Source: Residential smart meters: Refer to Figure 3-18. Residential cost reflective tariffs: Refer to Figure 3-21.
Note: Movement in cost reflective tariffs as % of smart meter installations calculated by dividing the movement in Residential cost reflective tariffs by the movement in Residential smart meters.

In contrast, Tasmania's significant increase in smart meter installations was not proportionate to an increase in customers on a cost reflective network tariff. As the rollout intensified in 2022, the adoption of cost reflective network tariffs decreased.

This low adoption is linked to TasNetworks' assignment policies, as their 2019-24 TSS allowed residential customers to opt-out from cost reflective network tariffs.[71] For the next 2024-29 regulatory period TasNetworks' 2024-29 TSS continues to allow customers to opt-

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70 AER, Final decisions, Ergon Energy and Energex Distribution Determination, TSS - 2020 to 2025, pg. 19, and SA Power Networks Distribution Determination 2020-25, amended TSS June 2020, pg. 10

71 TasNetworks, Revised TSS 2019-24 – Explanatory statement, April 2024, p 12.

out from assignment to a cost reflective network tariff, but only for a 12-month window following their smart meter installation.[72]

3.9.4.2 Lower take-up of cost reflective network tariffs for non-residential low voltage customers

For non-residential low voltage customers there is less correlation between a smart meter installation and a customer moving to a cost reflective network tariff, although these differ between small business and large business customers.[73] Similar to residential customers, the movement of non-residential low voltage customers to cost reflective network tariffs is reflective of tariff reassignment policies. This enabled bulk reassignment events as well as a 12-month lag on reassignment in the ACT following smart meter installation.

Over 2019 to 2024, Endeavour Energy,[74] Essential Energy[75] and TasNetworks[76] enabled small non-residential low voltage customers to opt-out of their tariff reassignment. Further non-residential customers appear to have a higher opt out rate than residential customers, which decreased the take-up of cost reflective network tariffs in NSW and Tasmania.

Queensland and Northern Territory had no opt-out and no reassignment lag and (after bulk reassignments), with their later years showing a close correlation between a smart meter installation and assignment to a cost reflective network tariff.

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72 TasNetworks, Fact sheet - 2024-2029 Network pricing strategy, December 2023, p 1.

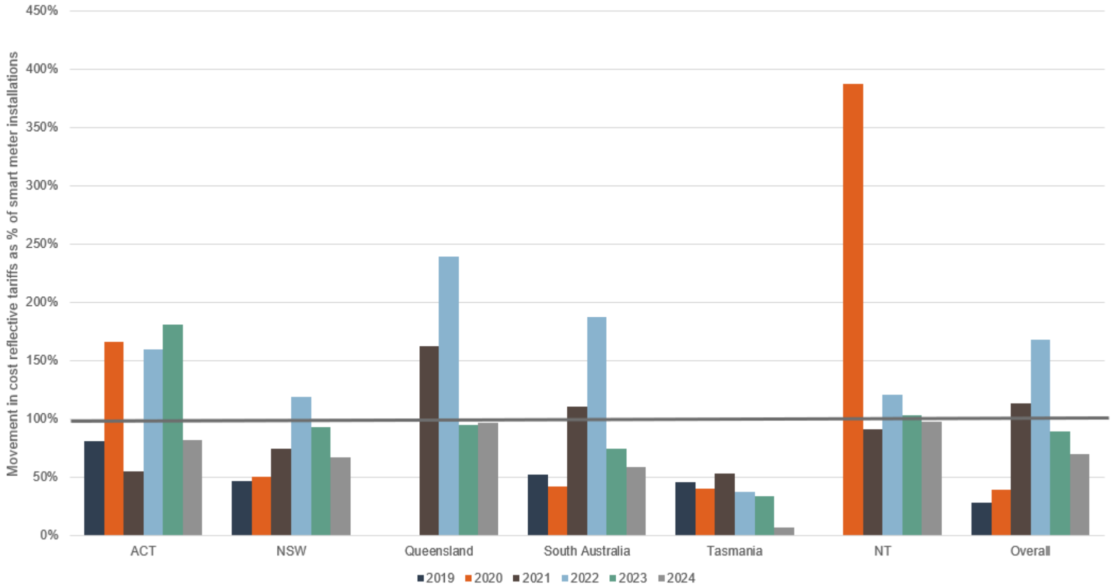
73 Larger business customers are more likely to already have a smart meter installed, decreasing the likelihood of a smart meter installation leading to a tariff reassignment to a cost reflective network tariff.

74 Endeavour Energy, Revised TSS 2019-24, April 2019, p 13.

75 Essential Energy, Revised TSS 2019-24, January 2019, p 10.

76 TasNetworks, Revised TSS 2019-24 – Explanatory statement, April 2024, p 12.

Figure 3-24 Non-residential low voltage cost reflective network tariff movement compared to smart meter installations - non-Victorian jurisdictions



Source: Non-residential (low voltage) smart meters: Refer to Figure 3-19. Non-residential low voltage cost reflective tariffs: Refer to Figure 3-22.
Note: Movement in cost reflective tariffs as % of smart meter installations calculated by dividing the movement in Non-residential low voltage cost reflective tariffs by the movement in Non-residential low voltage smart meters.

3.9.5 Rule change provides safeguards for customers on their retail bills

In addition to the universal uptake of smart meters in the NEM by 2030, the AEMC's Accelerating smart meter deployment rule change project, also proposed new safeguards for customers following a smart meter installation.[77] Submissions made during consultation highlighted concerns with retail demand tariffs, with the Australian Energy Council highlighting their complexity, noting that customers are not reasonably capable of understanding retail demand charges and/or how their energy usage relates to the tariff's price structure.[78]

In their final rule determination, the AEMC considered that additional customer safeguards were warranted to mitigate customer assignment to retail tariffs they did not understand.[79] The new requirements from this rule change will come into operation in December 2025.[80]

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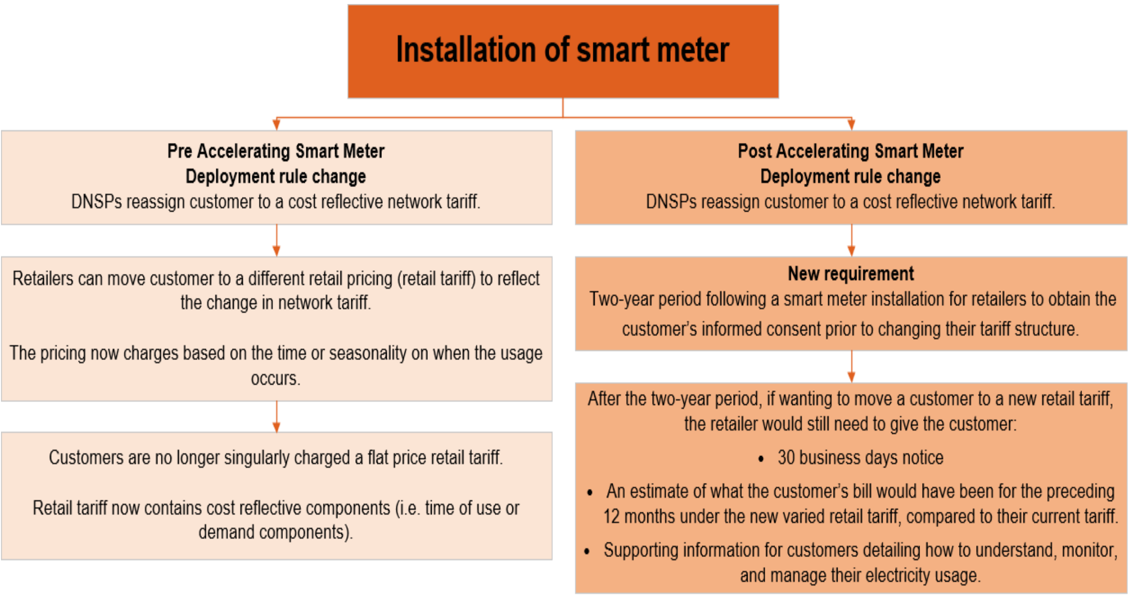
77 AEMC, Accelerating smart meter deployment - Rule change request, September 2023.

78 AEMC, Accelerating smart meter deployment - AEC, September 2024.

79 AEMC, Accelerating smart meter deployment - Final determination, November 2024, p 27-29.

80 AEMC, Accelerating smart meter deployment - Final determination, November 2024, p 61.

Figure 3-25 Additional requirements from Smart Meter Deployment rule change



Source: Rule determination - National Electricity Amendment (Accelerating Smart Meter Deployment) Rule

The AEMC's rule change introduced a requirement for retailers to obtain the customer's explicit informed consent for any retail tariff structure changes in the two years following a smart meter installation, and to provide certain information to customers when seeking that consent.

Their rule changes sought to ensure customers receive sufficient information from their retailers to understand the impact of any new retail offer following a smart meter installation. Retailers must provide information to the customer on how to understand, monitor and manage their electricity usage under the new retail structure. The AEMC also believed this would help minimise negative customer impacts such as 'bill shock' and build social licence with customers for the smart meter rollout.[81]

The AEMC also introduced a requirement for designated retailers to make a flat retail tariff available to customers with a smart meter although jurisdictions would need a local instrument to apply this rule.[82] To date, Queensland and South Australia have introduced such an instrument. The requirement offers additional protection for customers who can't meaningfully shift their consumption to benefit from cost-reflective retail tariffs or find cost reflective tariffs complex.[83]

These changes may impact the expediency of reassigning cost reflective retail tariffs, when the customer has a smart meter installed. However, this won't decrease the transition of customers to cost reflective network tariffs, as the AEMC's rule determination specifically noted that there were no changes to existing network tariff arrangements. DNSPs will continue to reassign customers to cost reflective network tariffs after a smart meter is

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81 AEMC, Rule determination: Accelerating smart meter deployment rule, November 2024, pp 27-31.

82 The designated (or local area) retailers are based on a customer's location. These retailers must provide an energy contract to establish a new connection to the electricity network, or for other matters.

83 In accordance with the requirements of the NERL, jurisdictions need to opt into this new flat tariff requirement and will only apply in a jurisdiction if implemented by a local instrument.

installed in accordance with their approved TSS. This leaves retailers facing an incentive to use alternative business tools/mechanism to assist their customers to manage their energy use in ways that increase efficient use of network capacity.

4 Gas distribution network operational performance

This chapter focuses on the performance of gas DNSPs for the 2024 regulatory year. We are reporting on the three scheme (transmission) pipelines: Amadeus Gas Pipeline, Roma Brisbane Pipeline and Victorian Transmission System through the operational and financial datasets (Microsoft Excel workbooks) and gas TNSP infographics published alongside this report.

References to NSPs in this chapter relates to gas DNSPs and TNSPs.

In 2024 the regulatory year for all gas DNSPs was the same for the first time. Previously, the regulatory year for Victorian DNSPs commenced on 1 January each year, but it now starts on 1 July, consistent with the other jurisdictions.

In last year's report we annualised operational performance data for the Victorian DNSPs to account for a 6-month transitional period. Our analysis noted this impacted their 2023 data, most noticeably in the gas delivered and UAFG, and therefore stakeholders should be cautious about making any significant conclusions from the data.[84]

The expenditures for gas NSPs are the same as electricity NSPs; opex is for the day-to-day operations of the network, whilst capex is spent on infrastructure investment. Similar to electricity NSPs, a gas DNSPs' capex and opex is recovered through the revenue building blocks, with forecasts determined by the AER to incentivise efficiency gains and lower spends. This incentive-based regulation will lead to lower forecasts in future years and lower network costs for customers.

4.1 Gas demand uncertainty continues to impact gas DNSPs

In November 2021, we published an issues paper, Regulating gas pipelines under uncertainty, which addressed issues we will face when making future access arrangement determinations for NSPs.[85] The paper noted that the rate of existing residential gas customers electrifying their appliances will impact the pace of decline in gas demand in future years, which could result in:

- Network costs being shared amongst fewer customers
- Customers who are unable to electrify, such as renters and low-income households
- Future gas customers bearing the cost of any unrecovered past network investment
- Price volatility and uncertainty further reducing demand
- Potential stranding of the gas distribution networks.

84 AER, Electricity and gas networks performance report 2024, September 2024, p 50.

85 AER, Electricity and gas networks performance report 2024, September 2024, p 51.

State and territory governments have already started to implement measures to reduce residential and small commercial customers reliance on gas. In our final determination for Jemena Gas Networks 2025-30 access arrangement, we noted that declining gas demand for gas distribution network services was the most significant expected driver of future rising gas distribution network costs. Further, we noted that a more customers leave the gas distribution networks, there will be fewer customers to share the fixed costs of providing the gas distribution network services.[86]

This final determination also noted the differing opinion of stakeholders. Industrial customers expressed support for investing now into the gas distribution networks to develop renewable gas supply, while consumer advocates expressed concern about the potentially worsening asset stranding risk, with that risk inherently being transferred to consumers.[87] These are issues that will continue to evolve in future years, as governments, industry and other stakeholders grapple with the role of gas networks in the energy transition.

The uncertainty of the pace of decline in gas demand is omnipresent in our gas network performance reporting, as it differs across each DNSP and affects their revenues, expenditures, the valuation of their network assets and their gas delivered.

4.2 Gas distribution costs remained low for customers

DNSPs are monopoly business that distribute gas to residential customers, commercial businesses, and industries. Historically, DNSPs have been regulated under a weighted average price cap form of control, which differs from a revenue cap. The weighted average price cap uses the building block revenue forecast and forecast demand over the access arrangement period to create the target revenue for the regulatory year. This involves determining a set of initial year tariffs and a series of X-factors[88] for the access arrangement period for the NSPs. The X-factors along with actual inflation, changes in demand and other factors constrain annual price increases on reference tariffs.

In contrast to revenue caps, the weighted average price cap enables NSPs to earn above or below the revenue set in the building blocks, due to actual demand being higher or lower than forecast. The use of the weighted average price cap places the ‘demand risk’ on NSPs and not customers, where lower demand results in lower revenues for NSPs whilst higher demand results in higher revenues.

In our final decision for JGN’s 2025-30 access arrangement, we approved JGN’s proposed hybrid tariff variation mechanism for its gas transportation reference service. This hybrid tariff variation mechanism was the first time the AER has approved a mechanism incorporating elements of both weighted average price cap regulation and revenue cap regulation.

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86 AER, Final decision – JGN access arrangement 2025-30, May 2025, pp v-vi.

87 AER, Final decision – JGN access arrangement 2025-30, May 2025, pp v-vi.

88 The X-factor is used with CPI to smooth the revenue an NSP will collect each regulatory year. This X-factor is an input in the control formula applied in annual pricing and is the change in real revenue/price from year-to-year. The X-factor is updated annually for changes in the allowed return on debt.

In making our decision we noted hybrid tariff variation mechanism was an additional method to manage demand uncertainty, both for JGN and its customer. Further, we considered the mechanism appropriately balanced the allocation of volume risk between JGN and its customers. Our decision also encouraged other gas DNSPs to consider similar approaches.[89]

4.2.1 Revenues remained low as customers use less gas

Revenue in this chapter relates only to the forecast and actual revenues from reference services, which for DNSPs are haulage reference services. Due to the bespoke nature of an NSPs access arrangement, this can also include non-reference services.[90] Categorising revenue in this way does not materially change our analysis, as reference prices influence the price that NSPs may charge for non-reference service.

In 2024 customers paid an average of $347 to DNSPs, an increase in real terms of $16 from 2023. Overall, this led to DNSPs recovering $1.6b from customers, a $90m (6.1%) increase from the previous year.

Historically the revenue recovered and revenue per customer in 2024 is the second lowest in our DNSP operational performance dataset. When excluding 2023, which was affected by annualising the six-month transitional period, both the total revenue and revenue per customer were the lowest in our dataset.

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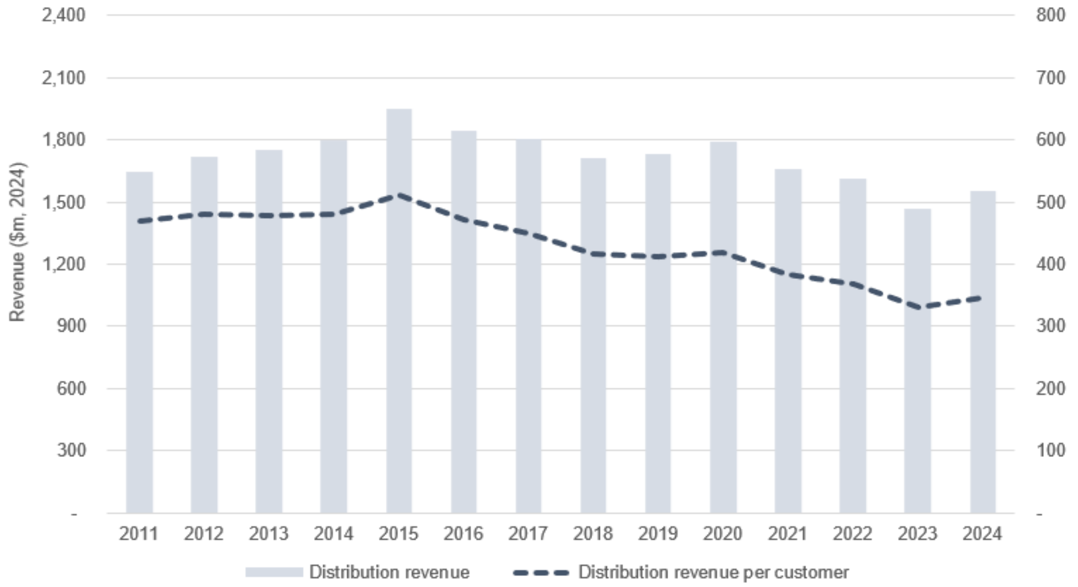
89 JGN, Final decision - JGN access arrangement 2025-30 - Overview, May 2025, p ix.

90 This difference is more pronounced between DNSPs and TNSPs. This is due TNSPs having a higher proportion of large customers with bespoke commercial arrangements, TNSPs (particularly Amadeus and RBP) provide a higher proportion of non-reference services. As noted above, this version of the 2025 Electricity and gas networks performance report does not include information on TNSPs.

Figure 4-1 Distribution revenue and revenue per customer - DNSPs - $ real 2024



Source: Distribution revenue: Annual RINs - F3.1 Reference services, Customer numbers: Annual RINs - S1.1 Customer numbers by customer type.
Note: AER calculation to convert to $ June 2024 terms. Distribution revenue per customer calculated by dividing DNSP's distribution revenue by DNSP's customer numbers.

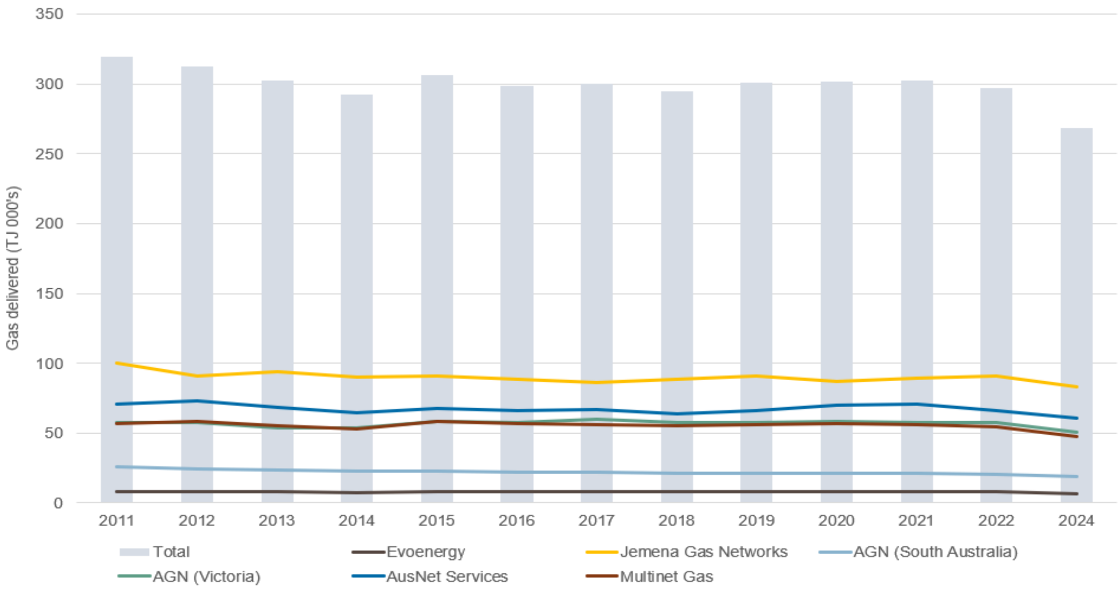
4.2.1.1 Milder temperatures contribute to lower revenues in 2024

In our operational performance dataset, we compare actual revenue against the target revenue for the regulatory year. Target revenue is based on the annually adjusted tariffs and actual demand from two years prior. For the 2024 regulatory year, the target revenue for Evoenergy, Jemena Gas Networks and AGN (South Australia) was based on the demand from 2022.[91]

In 2024, the gas delivered by DNSPs decreased by 10% from 2022, resulting in Evoenergy, Jemena Gas Networks and AGN (South Australia) earning less than their target revenues. For the Victorian DNSPs, the decrease did not impact the revenues earnt in 2024, as their revenues were determined based on their forecast demand.

91 The 2024 target revenue for Victorian DNSPs was based on the forecast demand and year 1 tariff prices from their 2023-28 access arrangement.

Figure 4-2 Gas delivered - Total and by DNSP



Source: Gas delivered: Annual RINs - N1.1 Demand
Note: Due to an over representation of warmer months during the six-month transitional period for Victorian DNSPs, we have removed 2023 from our analysis. This is discussed in detail in last year's report.

A decrease in gas demand of 10% is significant in our gas dataset, with this decrease from 2022 driven by lower gas delivered to residential and industrial customers.

Figure 4-3 Contributions to annual movement in gas delivered

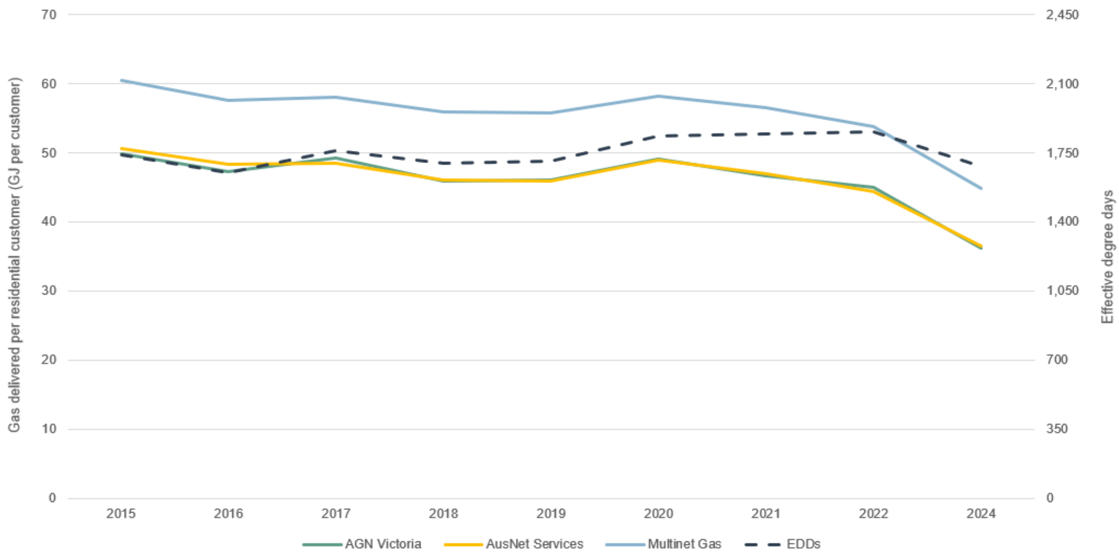
Source: Gas delivered: Annual RINs - N1.1 Demand by customer type
Note: Due to an over representation of warmer months during the six-month annualisation for Victorian DNSPs, we have removed 2023 from our analysis. This is discussed in detail in last year's report. Contributions to annual movement calculated by dividing annual movement in customer type by the total movement for regulatory year.

Annual movement of gas delivered can be attributable to several factors, which differ between DNSPs and jurisdictions. JGN and AGN (South Australia) have proportionately lower residential consumption, so movement is more likely attributable to industrial customers. For these DNSPs, gas usage is more likely to be driven by business conditions and strategy, changes to supply or connection sources, and shutdowns or maintenance of premises.

The factors differ for residential customers, who are a larger component of the Victorian DNSPs customer base.[92] Movement in residential gas usage can be due to the electrification of heating and cooking appliances and associated jurisdictional policies, customer preference on gas use with cost-of-living pressures and weather conditions.

The best method to determine the use of residential gas demand for weather conditions in Victoria, is effective degree days (EDDs). This measures the combined impact of average temperature, wind and number of sunshine hours to model the daily gas demand-weather relationship in Victoria. When comparing the EDDs for Victoria to gas delivered for each residential customer for each Victorian DNSP, there is a distinct correlation. This indicates that milder temperatures during the 2024 regulatory year have contributed to the lower residential gas consumption in 2024.

Figure 4-4 Gas delivered per residential customer and EDD - Victorian DNSPs



Source: Gas delivered: Annual RINs - N1.1 Demand by customer type. Effective degree days: Information request to DNSPs.
Note: Due to an over representation of warmer months during the six-month transitional period for Victorian DNSPs, we have not included gas delivered and EDDs for the 2023 regulatory year.

Despite EDDs being correlated with residential gas demand in Victoria, the correlation appears to be declining relative to historical trends, with weather conditions having a lower impact on residential gas delivered. This appears to be caused by different factors including electrification and improved efficiency of newer gas appliances and changing consumer behaviour from cost-of-living pressures.

Going forward, although there is uncertainty in relation to the pace of decline in gas demand from the electrification of household appliances and other policy developments in the energy

92 Residential customers are also the largest component of Evoenergy customer base and consume more gas than commercial and industrial customers in their distribution network.

transition, there is a forecast for lower gas delivered by gas distribution networks in the short to medium term.

In AEMO's Gas Statement of Opportunities, the step change scenario's assumptions involve residential and commercial consumption declining in the short term, with more significant electrification of appliances forecast in the medium to longer term (particularly in Victoria and NSW). This is expected to forecast residential and small commercial gas consumption by 125 petajoules (PJ), from 176 PJ in 2025 to 51 PJ in 2044, despite rising population and economic growth.[93]

4.2.2 Gas DNSPs earn minimal incentive scheme rewards

The incentive schemes for gas NSPs differ from those for electricity NSPs as there are no specific incentive schemes in relation to service outcomes or reliability.[94]

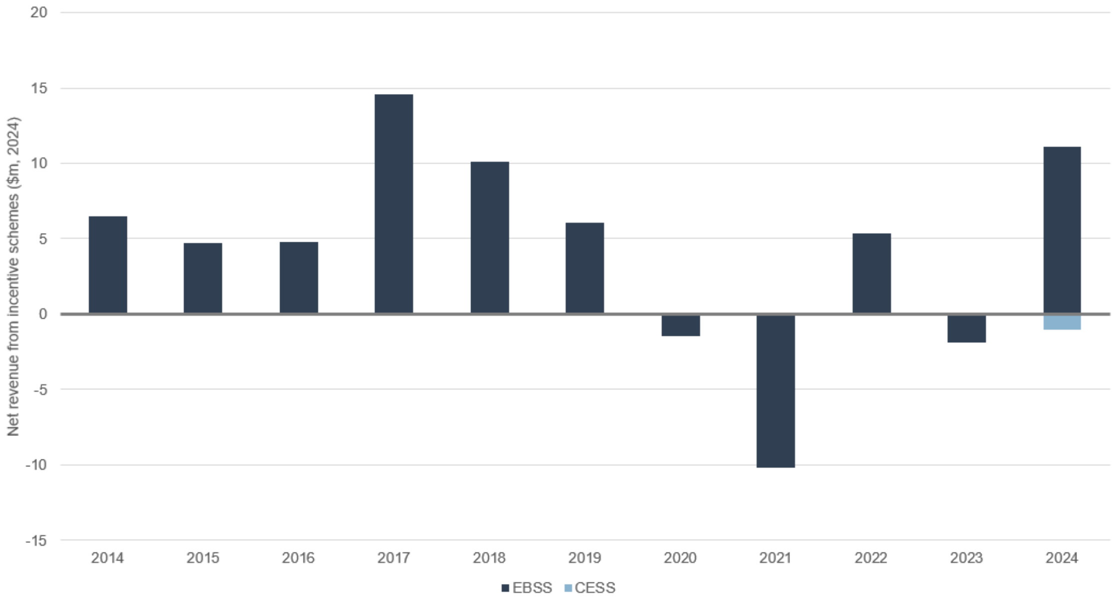
As seen with the electricity NSPs, incentive schemes are designed to deliver better outcomes for customers and promote achievement of the NGO, with the overall benefits to customers outweighing the incentive revenues provided to the DNSPs.

Relative to electricity NSPs, historically there has been minimal revenues earned by DNSPs in relation to their incentive scheme performance in previous access arrangement periods. In 2024, DNSPs earned $10m in revenues from incentive scheme rewards, representing less than 1% of total distribution revenues. This was an increase of $12m from 2023, where DNSPs paid small penalties, but no revenues were earned.

93 AEMO, 2025 Gas statement of opportunities, March 2025, p 23.

94 Although there are no incentive schemes in relation to service delivery for NSPs, the Essential Services Commission requires the Victorian DNSPs to make guaranteed service level (GSL) payments to customers who receive a level of service worse than a specific threshold or level. These relate to late or missed appointments, delay to new connections, frequency of outages and the duration of outages.

Figure 4-5 Revenue from incentive schemes - DNSPs - $ real 2024

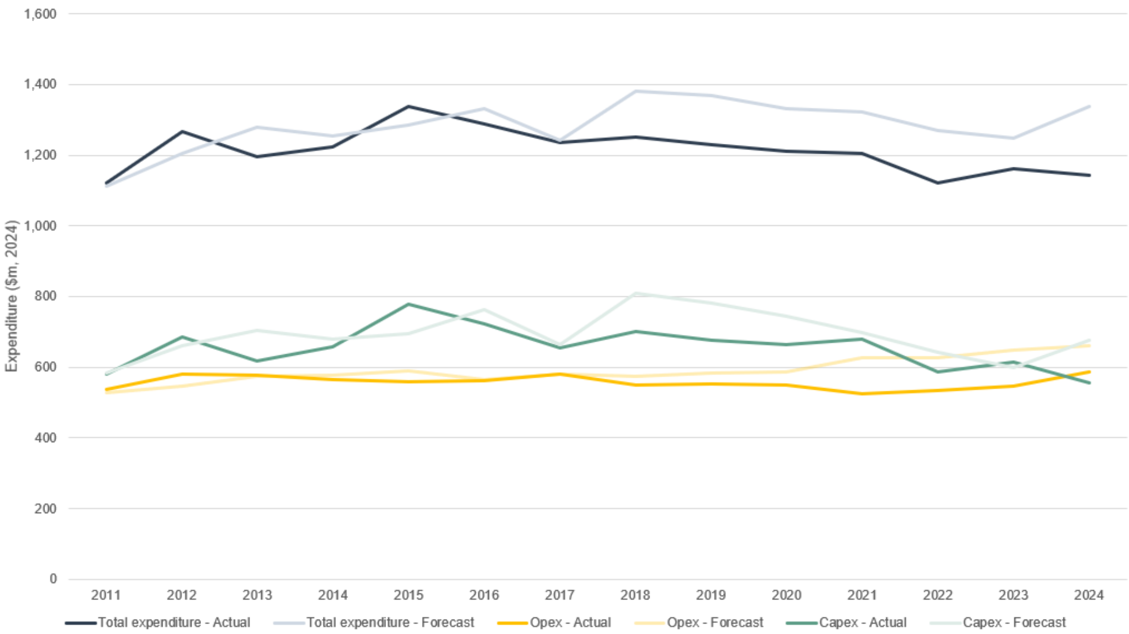


Source: Incentive scheme revenues/payments from Annual RIN table F3.6 Revenue - Rewards and penalties from incentive schemes. Where incentive schemes revenue/payments are not available, data is from respective DNSP's PTRM, 'Revenue adjustments.'
Note: AER calculation to convert to $ June 2024 terms.

4.3 Gas DNSPs underspend on expenditure allowances

In 2024, DNSP expenditure decreased slightly by 2% to $1.1b, with in real terms a 11% and 18% underspend in opex and capex respectively. In comparison to 2023, the opex spend increased by 7% whilst the capex investment decreased by 10%.

Figure 4-6 Total expenditure - DNSPs - $ real 2024

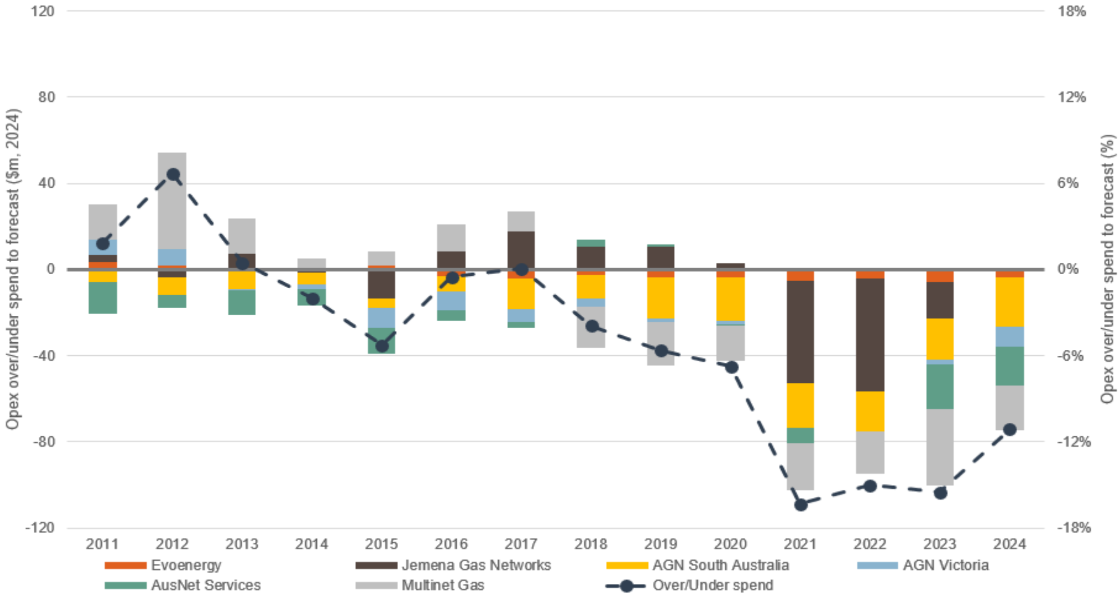


Source: Actual capex RFMs - RFM input - actual capex, actual asset disposal, actual capital contributions, or where not available in an RFM, annual RINs - F2.4 Capex by asset class, F2.5 Capital contributions by asset class, F2.6 Disposals by asset class. Actual Opex: Annual RINs - F4.1 Opex by purpose. Forecast capex: PTRM Input - ‘Forecast net capex.’ Forecast opex: PTRM Input - ‘Forecast operating and maintenance expenditure.’ Note: AER calculation to convert to $ June 2024 terms. Net capex is gross capex less capital contributions and disposals. Actual and forecast total expenditure is the sum of capex and opex.

4.3.1 Gas DNSPs’ opex underspends lead to higher returns

Gas DNSPs have had 7 consecutive underspends of their opex allowance (from 2018 to 2024) for a collective underspend of $465m. This was the case for most DNSPs in this period, most noticeably Multinet Gas, which reversed their overspends from 2011 to 2017.

Figure 4-7 Opex over/under spend to forecast - DNSPs - $ real 2024



Source: Actual Opex: Annual RINs - F4.1 Opex by purpose. Forecast opex: PTRM Input - 'Forecast operating and maintenance expenditure.'
Note: AER calculation to convert to $ June 2024 terms. Opex over/under calculated by comparing actual opex against forecast opex for respective regulatory year

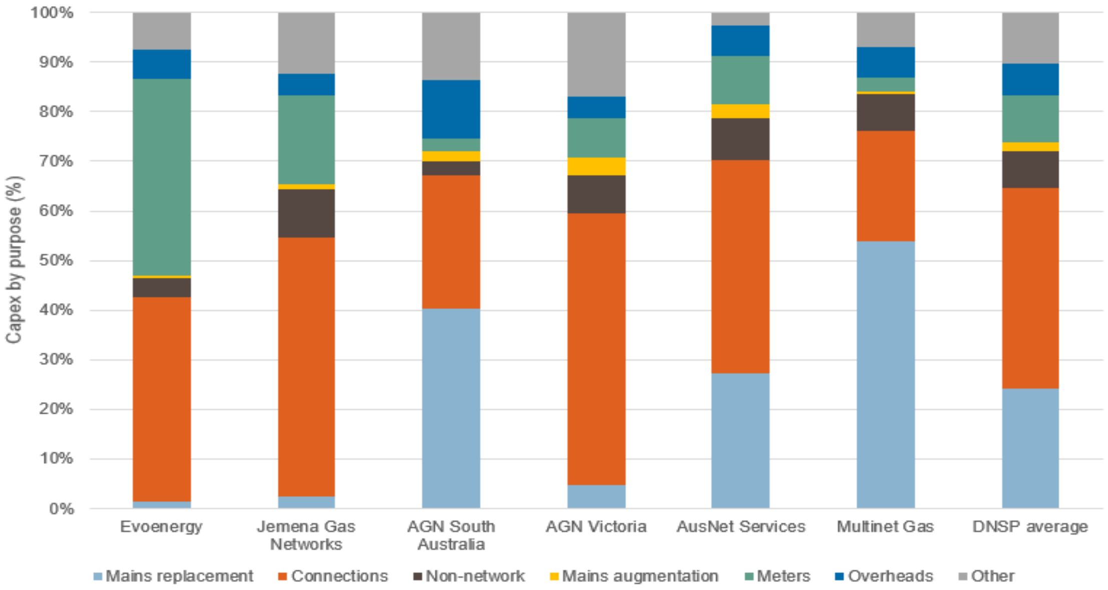
Opex efficiency benefits both NSPs and consumers and is a key feature of our incentive-based regulatory framework. Lower opex enables NSPs to earn returns higher than their allowed returns and decreases opex forecasts in future access arrangements. Financial performance is discussed further in Chapter 5.

4.3.2 Gas DNSPs' capex investment based on new connections and mains replacements

DNSP capital costs have historically been for new connections and mains replacements. Connections expenditure has been driven by the costs required to connect customers to gas supply, whilst mains replacement expenditure has been driven by the replacement of cast iron pipeline with pipeline using polyethene and polyamide materials. These "plastic" pipelines have several advantages, namely their resistance to damage from corrosion or the effects of gas, ease of installation and cost effectiveness.

In 2024, DNSPs invested $555m in the gas distribution networks, a 10% decrease from 2023. Similar to prior years, 65% of the capital investment by DNSPs was in connections and mains replacements.

Figure 4-8 Capex by driver - DNSPs - $ real 2024



Source: Capex by purpose: Annual RINs - E1.1.1 Reference Services.
Note: AER calculation to convert to $ June 2024 terms. Other consists of ICT, telemetry and other capex

The differing capex profile of the gas DNSPs is due to each DNSP connecting differing numbers of customers to their network and being on different stages of their mains replacement program. Each DNSP (except Evoenergy) started their mains replacement programs at different times, with Jemena Gas Networks principally replacing their cast iron pipelines before 2011.[95] AGN Victoria finalised the replacement of its low pressure mains replacement program in its previous access arrangement, and only AGN South Australia, AusNet Services and Multinet Gas had material mains replacement capex in their current access arrangement.[96] We discussed the necessity of mains replacement programs in last year's report.[97]

In relation to their mains replacement progress, we note that at the conclusion of the 2024 regulatory year, Multinet had 696km of cast iron pipeline, whilst AGN (South Australia) and AusNet Services had 45km and 41km respectively.

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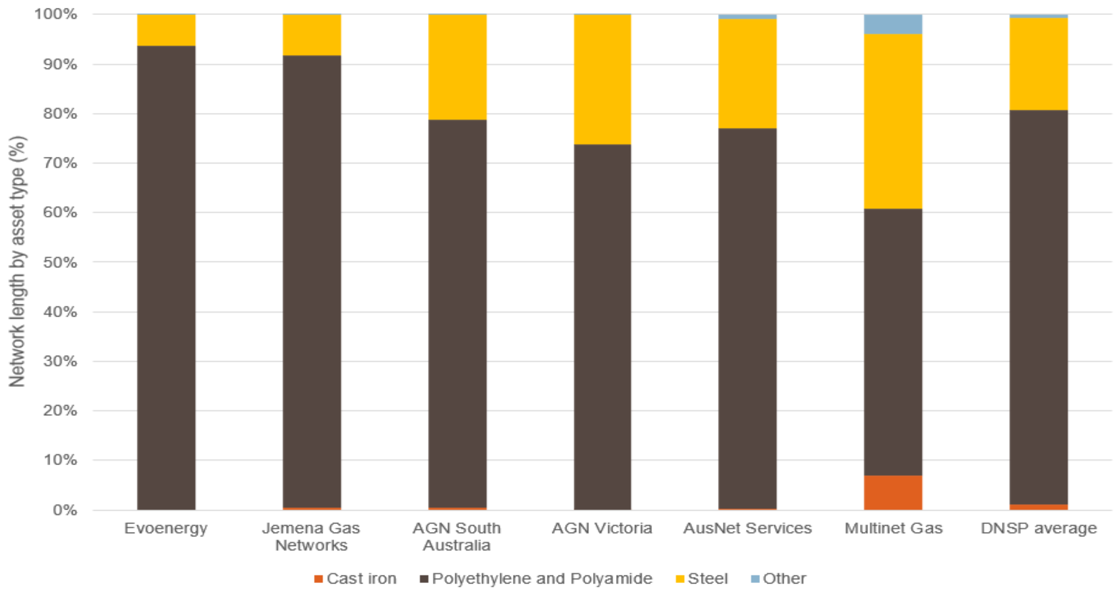
95 Evoenergy's gas network was commissioned in 1982 using polyethene and polyamide materials instead of cast iron materials.

96 AGN Victoria, AGN Victoria final plan 2023-28, July 2022, p 21.

97 AER, Electricity and gas networks performance report 2024, p 61

Figure 4-9 Network length by asset type - DNSPs



Source: Network characteristics by pressure and type: Annual RINs - E1.1.1 Reference Services.
Note: AER calculation to convert to $ June 2024 terms. Other consists of ICT, telemetry and other capex

In their current access arrangement:

- AGN South Australia has $267m of approved capex for mains replacement, with an expectation that approximately $100m will be incurred in 2025 and 2026. Mains replacement constitutes 45% of their total approved capex.[98]
- AusNet Services has approved capex of $133m for mains replacement, with $103m approved for the period 2025 to 2028. Mains replacement constitutes 31% of their total approved capex.[99]
- Multinet Gas has approved capex of $424m for mains replacement, with $346m approved for the period 2025 to 2028. Mains replacement constitutes 62% of their total approved capex.[100]

Both AGN South Australia (2026) and AusNet Services (2028) plan to complete their mains replacement program in their current access arrangement period.[101] Multinet Gas plans to complete their mains replacement program in 2031.

We discuss the changes in connection numbers that impact connections capex in 2024 below in section 4.4.

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98 AER, Final Decision: AGN South Australia 2021-26 Capex, April 2021, p 8. Adjusted to $ June 2024 dollars.

99 AER, Final decision: AusNet Services 2023-28 Capex, June 2023, p 6.

100 AER, Final decision - Multinet Gas 2023-28 - Capex, June 2023, p 6.

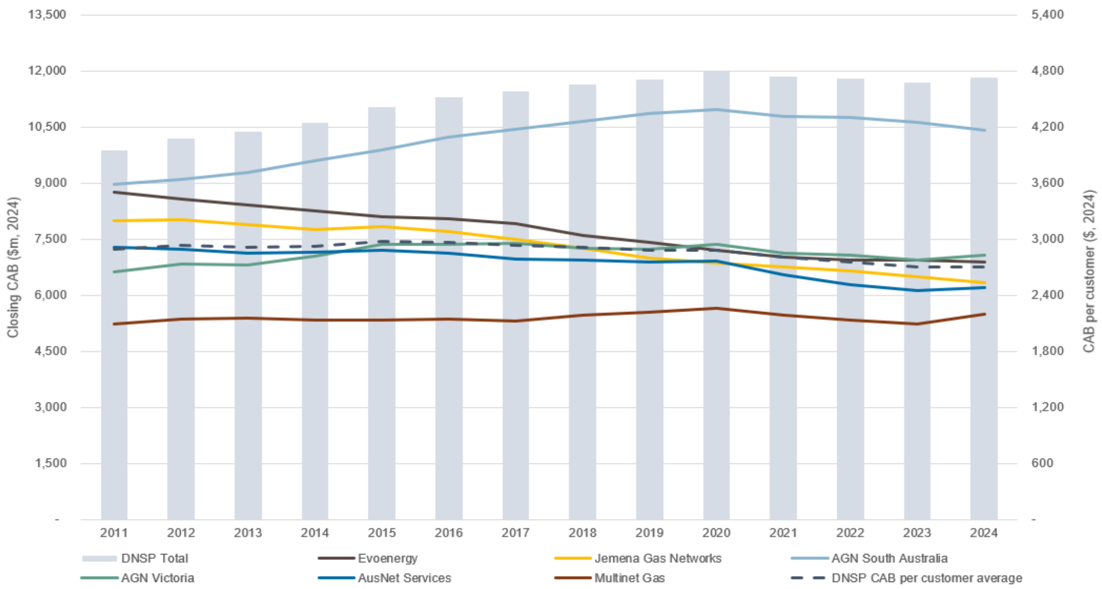
101 AGN, Media release, AER Final decision supports blending renewable gas into the South Australian gas supply, April 2021; AER, ASG - Access Arrangement Information 2024-28, July 2022, p 87.

4.3.3 Gas DNSPs asset base increased amidst uncertainty with decline in gas demand

The capital asset base (CAB) is the total economic value of the network assets used by the DNSPs to provide network services. The valuation of a DNSP's CAB is often dependent on the geographical size and location of their network, whilst the CAB per customer is based on the customer density of their network. This is why AGN South Australia's and Multinet Gas's CAB per customers is the highest and lowest respectively across the DNSPs.[102]

In 2024, the total CAB increased in real terms by 1.2%, with the total DNSP CAB per customer remaining consistent with last year.

Figure 4-10 CABs and CAB per customer - DNSPs - $ real 2024



Source: CAB: RFMs - 'Total capital base roll forward' - Interim closing capital base, or where unavailable using Annual RINs - F10.1 'Capital base values'. Customer numbers: Annual RINs - S1.1 'Customer numbers by customer type'.
Note: AER calculation to convert to $ June 2024 terms. CAB per customer calculated by dividing total CAB by total customer base and also DNSPs CAB by DNSPs customer base.

The differing CAB per customer impacts the distribution network costs paid by customers, as higher CAB values are reflected in larger return on capital and return of capital building blocks. The return of capital building block decreases the CAB value as the network assets are depreciated across their working life, with the total CAB decreasing in a regulatory year in real terms when the total depreciation exceeds the new investment in network assets.

As noted above, the uncertainty in relation to the pace of decline in gas demand has led to concerns of potential stranding of network assets. One of the potential options to this issue, is to accelerate the depreciation of an NSP's network assets by shortening the life of the network assets or increasing the rate at which they are depreciated. This is allowed by the

[102] Further discussion of CAB per network length was discussed in last year's report.

NGR, which enable us to accelerate depreciation where necessary to allow cost recovery and generate efficient prices as new information becomes available.[103]

We have considered accelerated depreciation in the Victorian DNSPs and Jemena Gas Networks recent access arrangement determinations. In each determination, we have allowed accelerated depreciation to reduce the stranded asset risk associated from long term demand uncertainty. However, to balance the stranding risk for future customers against the short-term price impacts for current customers, in their most recent determinations we have limited accelerated depreciation to 1.5% per annum real price change for Victorian DNSPs[104] and 0.5% per annum real price change for JGN.[105]

AusNet Services 2023-28 access arrangement variation proposal

In September 2024, AusNet Services submitted a proposal to vary its approved 2023-28 access arrangement by increasing its accelerated depreciation and making associated adjustments to their capex and opex forecasts. This involved AusNet Services recovering additional revenue from customers in the last three years of the access arrangement.

This proposal was based on recent initiatives from the Victorian Government and the ESC, in relation to partial bans on new gas connections, cost reflective charges for connections and intentions to undertake regulatory impact statement (RIS) assessments for electrification of commercial buildings and gas appliance bans.

Our draft decision did not approve AusNet Services' proposal, because we were not satisfied it had justified the various elements. We believed the Victorian policy and regulatory changes would accrue more slowly than proposed, and there was uncertainty as to how gas customers would respond. Further, some elements of AusNet Services' proposal were already catered for through flexibility mechanisms in their current 2023-28 access arrangement and we considered that intervention was not required.

In response to our draft decision, AusNet Services submitted a letter indicating it had accepted our draft decision and would not submit a revised proposal. In May 2025 we made our final decision to not accept AusNet Services' proposal, using the reasons set out in the draft decision.

Source: AER, Final decision - AusNet Services 2023-28 access arrangement variation proposal, May 2025.

The decision to enable some accelerated depreciation is reflective of our issues paper on *Regulating gas pipelines under uncertainty*. The paper noted that opportunity and flexibility for adjustment is greatest when we act as soon as we can to minimise the adverse impact of a decline in gas demand.

The decision to allow for measured levels of accelerated depreciation, was also made to provide the right incentives for DNSPs to make efficient investments in the transition to net zero. DNSPs will continue to incur maintenance and replacement costs to ensure their pipeline assets can provide safe and reliable network services for the remaining customers.

103 NGR, Rules 89(1) (b) and (c)

104 AER, Final decision - AusNet Services access arrangement 2023-28 - Overview, June 2023, p 24.

105 AER, Final decision - JGN access arrangement 2025-30 - Overview, May 2025, p. vii

Without accelerated depreciation, networks may potentially deter or defer important investments in their network assets which would not be in the long-term interest of consumers.

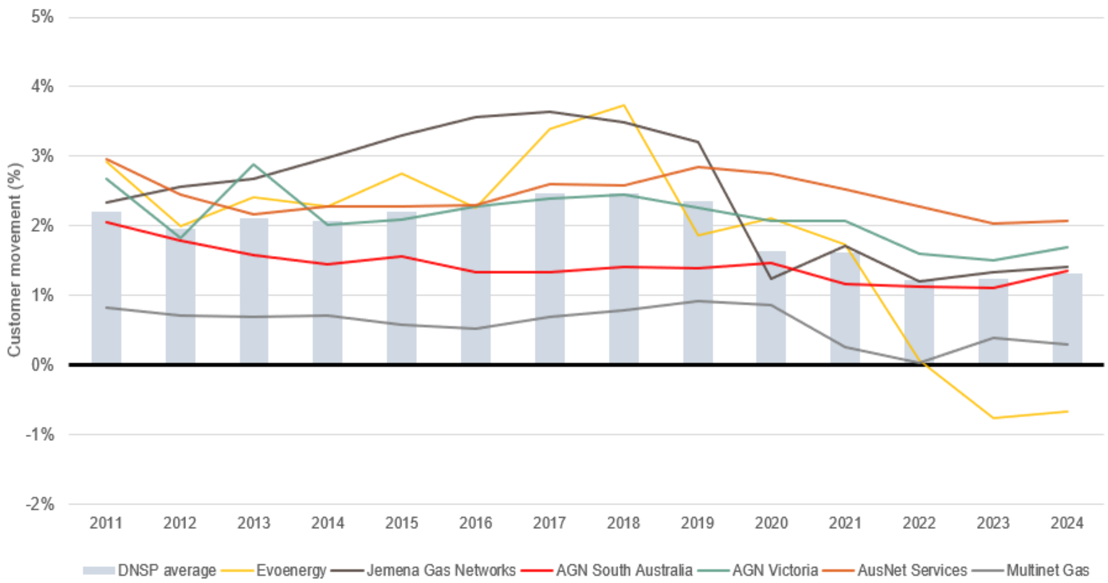
4.4 Gas DNSP customer base increases slightly in 2024

Gas distribution networks have traditionally been run as growth assets with costs spread over a growing customer base. Australia's energy transformation is changing the outlook for distribution networks and the role of gas as an energy source for their customers. New connections will be a key factor in determining the future of gas distribution networks going forward.

In this report and in our operational performance dataset we have included more details on movements in gas residential connections to provide stakeholders with additional information to consider the future of gas distribution networks.

In 2024, there was a 1.3% increase in net residential customer connections, a slight increase from 2023, with all DNSPs except Evoenergy increasing their customer base in 2024. This is the second consecutive regulatory year Evoenergy has decreased its customer base, following the implementation of the ACT regulations banning new gas connections. These regulations came into effect under the *Climate Change and Greenhouse Gas Reduction Act 2010* in December 2023, half-way through the 2023 regulatory year.

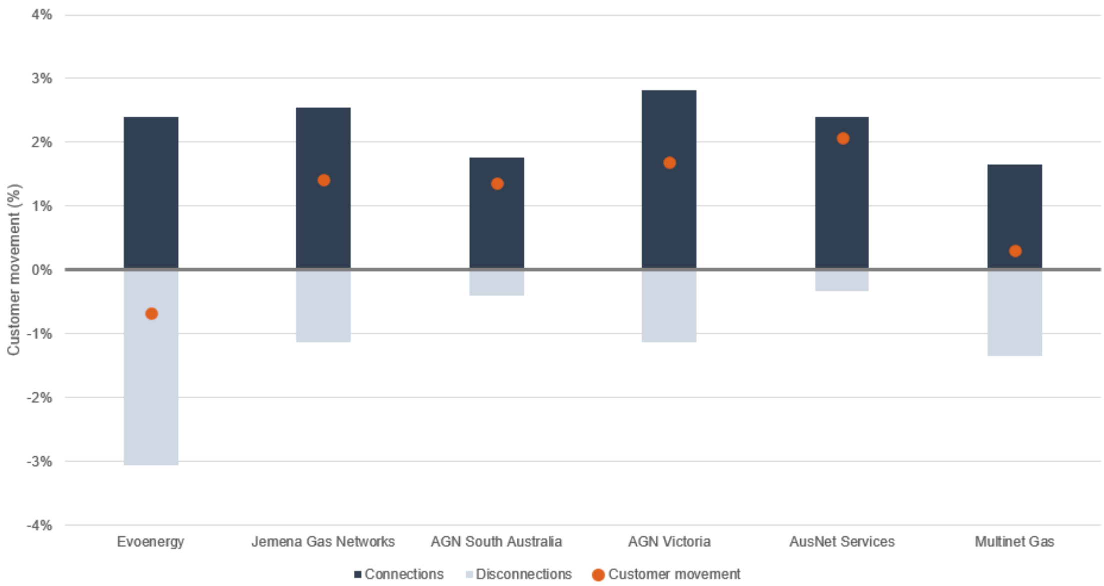
Figure 4-11 Residential customer numbers growth - DNSPs



Source: Residential customer numbers: Annual RINs - S1.1 Customer numbers by customer type - Residential
Note: Residential customer growth determined by percentage change in residential customer numbers from prior year.

Our 2024 report noted that gas connection restrictions in Victoria and the ACT for certain customers, [106] may lead to a decrease in their gas DNSPs customer base.[107] However for Victorian DNSPs this did not occur, as each DNSP increased their residential customer base in 2024.

Figure 4-12 Residential connections and disconnections - DNSPs - 2024



Source: Residential customer numbers: Annual RINs - S1.1 Customer numbers by customer type. Note: Connections and disconnections divided by total customer numbers.

The increase for the Victorian DNSPs is due to customers with approved planning permits being connected after the restrictions were implemented and the new connections restrictions only applying to new dwellings which required a planning permit. This involved gas DNSPs reticulating gas based on customer requests in new estates with existing planning permits or customers requesting a gas connection in knockdown rebuilds which don't require planning permits. AGN Victoria's gas connections were linked to the Commonwealth Governments' COVID HomeBuilder program which provided first home buyers and owner occupiers with a grant to build a new home or substantially renovate an existing home.[108]

The number of residential connections in Evoenergy's distribution network decreased in 2024 but remained consistent with connections for the 2022 regulatory year, which was before the ACT Regulations banning new gas connections came into effect. This was due to connection requests being made before the implementation of the Regulations and the Regulations not applying:[109]

- to the NSW region of Evoenergy's network (i.e. Queanbeyan and Bungendore)

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106 Victorian Government, Victoria's gas substitution roadmap, Department of Energy, Environment and Climate Action, accessed 11 April 2025. ACT Government, Regulation to prevent new gas connections starts in December, media release, November 2023.

107 AER, Electricity and gas networks performance report 2024, September 2024, p 66.

108 Australia Government - The Treasury, HomeBuilder, April 2021, accessed 11 April 2025.

109 ACT Government, Preventing new gas network connections, December 2023, accessed 11 April 2025.

- on National Land in the ACT (e.g. National Capital Authority Designated Area, Canberra Airport, HMAS Harman and Duntroon, among others)
- to industrial customers or commercial connections in commercial zones where there is an exemption by the Minister for Water, Energy and Emissions Reduction.

4.4.1 Victorian Government announces new policy on gas connections

The rate of existing residential gas customers electrifying some or all of their gas appliances will impact the pace of decline in gas demand in future years, which will flow onto our reporting of a gas DNSPs revenues, expenditures and the valuation of their network assets. We also discuss some of these impacts in section 4.1 of this report.

In June 2025, the Victorian Government announced their new policy in relation to electrification regulations.[110] The new regulations require all new residential and commercial buildings to be all-electric and existing gas hot water systems in residential buildings to be replaced with electric appliances at their end-of-life.[111]

The electrification regulations will commence in two stages. The building regulations will commence on 1 January 2027 for all-electric new homes and commercial buildings and 1 March 2027 for gas hot water system installation and replacements in existing homes.[112] Currently, more than half of all gas customers are in Victoria, with the revenues and network assets of the Victorian DNSPs being slightly less than half of the total revenue and CAB of all DNSPs.

Based on these dates, these restrictions will not be reported by gas DNSPs until their 2027 regulatory years. We will continue our reporting of customer's connections, disconnections and the overall customer base of gas DNSPs in future years, to assess how these are being impacted by the various state and territory gas connection policies.

4.5 UAFG and pipeline outages remained consistent

Our reporting of the service outcomes of gas distribution networks is limited to unaccounted for gas (UAFG) and pipeline outages.

Although there are no prescribed AER incentive schemes for service performance for DNSPs, due to the safety risks associated with gas, it is imperative that DNSPs provide a safe and reliable supply of gas to customers. Whilst there are a number of different measures of supply quality, network outages and UAFG are two measures that are readily quantifiable and reporting annually.

4.5.1 UAFG differs across the gas DNSPs

UAFG is the difference between the measured quantity of gas entering the network (gas receipts) and measured gas deliveries (gas withdrawals). UAFG can have various causes, however they can be broadly itemised into 5 categories: gas leakage (fugitive emissions),

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110 Victorian Government, Building Electrification Regulations Summary, June 2025, p 7.

111 The Victorian Government noted exemptions will apply to this requirement.

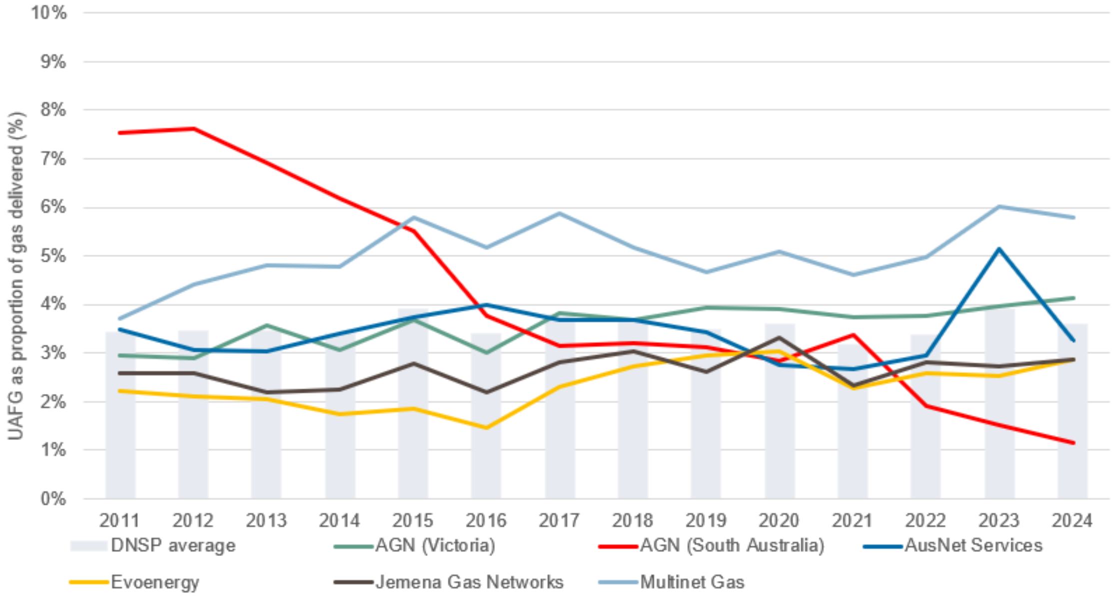
112 Victorian Government, Building Electrification Regulations Summary, June 2025, p 15.

metering errors, gas heating values (losses related to the quality of gas injected into the pipelines), data quality, and theft.[113]

UAFG is an important measure for customers both financially and for the environment, which we discussed in detail in last year's report.[114]

In 2024, there was an overall UAFG loss of 3.6%, a slight improvement from 3.9% in the prior year. Individually the loss rate differed across the DNSPs, with Victorian DNSPs (in particular, Multinet) having higher loss rates than Evoenergy, Jemena Gas Networks and AGN (South Australia).

Figure 4-13 UAFG proportion of gas delivered - DNSPs



Source: Gas delivered: Annual RINs - N1.1 Demand by customer type. UAFG: Annual RINs - S11.3 - Unaccounted for gas - distribution and transmission.
Note: UAFG loss rates calculated by dividing the DNSP's UAFG by the DNSP's gas delivered.

4.5.2 Pipeline outages remain infrequent

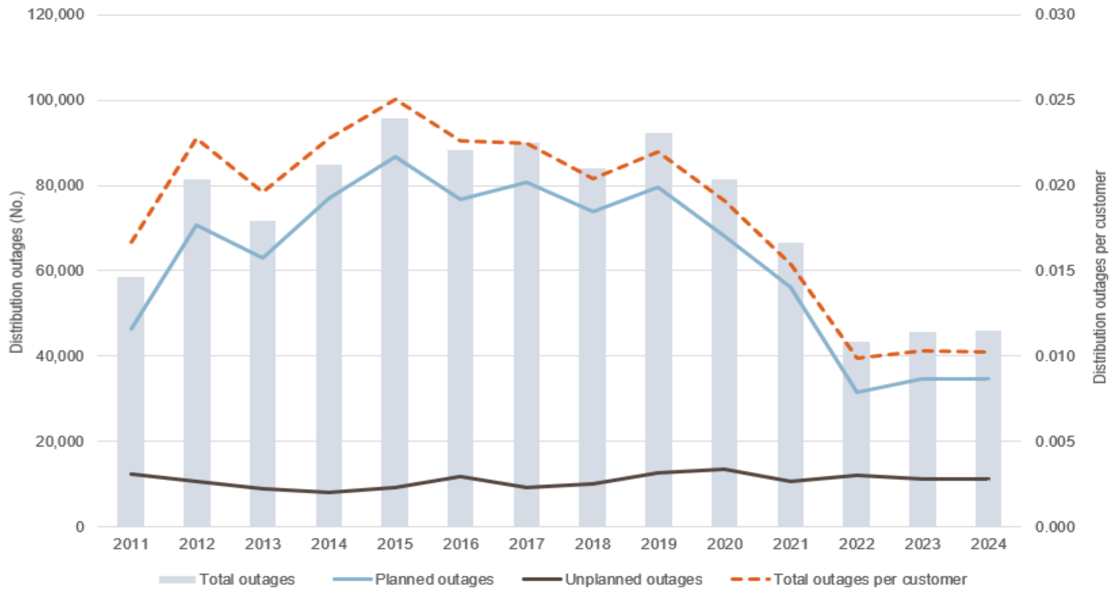
Pipeline outages remain infrequent for customers as the network assets are inherently reliable. This is due to network assets being substantially underground and more protected from adverse weather conditions than electricity networks and gas DNSPs can usually carry out works without causing supply outages.

Due to these factors, outages remained infrequent in 2024, continuing at the same low level as 2023, with customers experiencing 0.01 outages per customer on average.

113 ESC observed up to 17 different components within these 5 categories in Review of unaccounted for gas benchmarks: final decision, December 2022, p 7.

114 AER, Electricity and gas networks performance report 2024, September 2024, p 70.

Figure 4-14 Planned and unplanned outages – DNSPs



Sources: Planned Outages: Annual RIN - Table S11.1.1 'Network outages - planned.' Unplanned outages: Annual RIN - Table S11.1.1 'Network outages - unplanned.' Customer numbers: Annual RINs - S1.1 'Customer numbers by customer type'

Note: Outages is the sum of planned and unplanned outages. Outages per customer is the total outages divided by the total DNSP's customer numbers.

Based on the 2024 figures, statistically 1 in 100 customers will experience an outage on a distribution network each year. However, because gas is essential for industry and commercial businesses, as well as residential customers, a single outage can have a significant detrimental impact. Due to this, we will continue to report on outages and what is driving them in future years.

In assessing outages operational data, we note that different DNSPs may have adopted materially different approaches to reporting outages. While this data effectively tracks outage trends for individual gas DNSPs over time, it is limited in comparing the relative performance between different DNSPs.

5 Financial performance in 2024

Our performance reporting assesses the financial performance of NSPs, or network profitability, through three measures:

- Return on assets (RoA)
- Return on regulated equity (RoRE)
- Earnings before interest and tax (EBIT) per customer.

Explanatory notes which explain our approach to calculate each profitability measures are included in Appendices C, D, and E. Further information is also available in our Final position paper - profitability measures for electricity and gas network businesses and the illustrative RoRE model published alongside this report.

We report our financial performance data and the profitability measures exclusive (real) and inclusive (nominal) of inflation (through the indexation of the RAB/CAB). The RoA, RoRE[115] and EBIT per customer profitability measures included in this report are exclusive of inflation, i.e. an NSP's real returns, as our regulatory frameworks are designed to target a real rate of return. In the financial performance datasets, we publish alongside this report, we have inserted 'switches' which enable stakeholders to calculate the returns of an NSP inclusive or exclusive of the indexation of the RAB/CAB.[116]

Since 2022 we no longer report on a fourth profitability measure - RAB Multiples, which is calculated as the NSP's enterprise value divided by its RAB or CAB.

The regulatory framework is designed to compensate NSPs for efficiently incurred costs (such as opex, depreciation, interest costs and tax costs) and to provide them with an expected profit margin in line with the required return in the capital or financial markets for an investment of similar risk. This return is designed to attract efficient investment, if set at an appropriate level and supported by the incentive-based regulatory framework.

The incentive-based regulatory framework is based on encouraging efficiency by NSPs and therefore an NSP's actual performance will differ from the forecasts and benchmarks we set. These differences can occur for a number of reasons, some of which we discussed in last year's report.[117]

We report each of the three profitability measures for NSPs and gas DNSPs in this section as a sector, i.e. on a weighted average basis. This means that what is reported is the result

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

116 The financial performance model also enables stakeholders to assess a NSP's returns inclusive and exclusive of incentive schemes and the impact of inflation. For electricity DNSPs, stakeholders can also assess returns inclusive or exclusive of pass-through revenues.

117 AER, Electricity and gas network performance report 2024, September 2024, p 73.

in aggregate, where there can be differences in the underlying financial performance between individual NSPs.

5.1 Networks RoA returns decreased in 2024

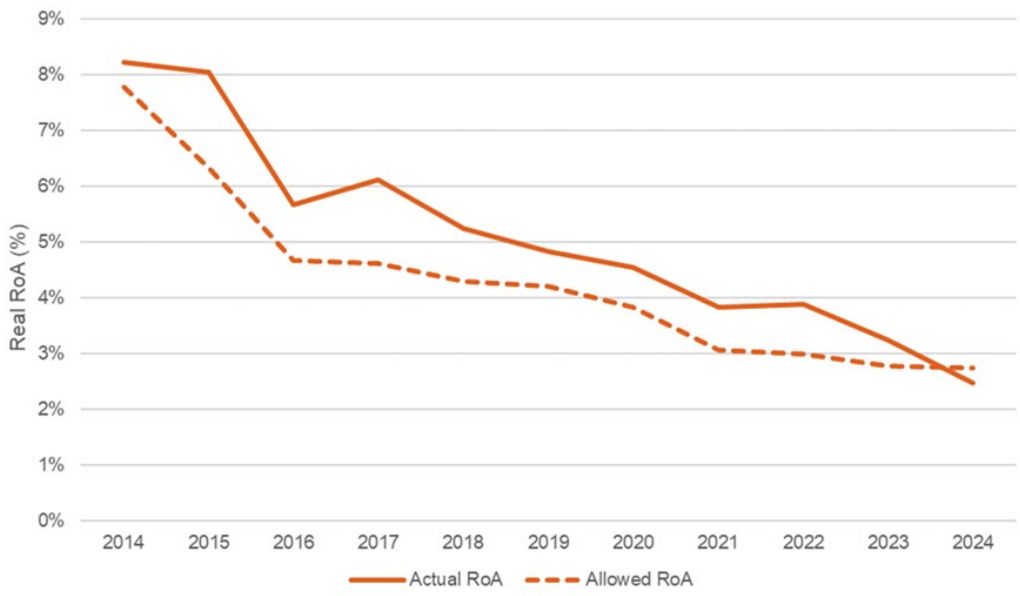
The RoA is measured as the earnings before interest and tax (EBIT) divided by the electricity NSP's RAB and the gas DNSP's CAB. This measure allows comparison of an NSP's EBIT profits against their allowed rate of return and calculates the EBIT that an NSP can earn from their RAB or CAB.

The RoA profitability measure is the best assessment on whether NSPs have returns greater than their allowed rate of returns and achieved the NEO or NGO. This is due to efficiency from capex, opex and incentive schemes being key features of our incentive-based regulatory framework, where the NSP's performance will benefit consumers in the form of lower network costs in the future and superior service levels.

5.1.1 Electricity NSPs have returns lower than allowed returns

In 2024, on a weighted average basis, electricity NSPs' RoA decreased by 0.8 percentage points (p.p), continuing the gradual decrease of RoA throughout our dataset. The decrease on a weighted average basis led to electricity NSPs, for the first time in our dataset, generating returns below their allowed rate of return.

Figure 5-1 Real RoA compared to allowed real RoA - electricity NSPs



Source: Electricity/Gas financial performance model, allowed real rate of return - PTRM 'WACC' sheet
Note: Financial performance numbers are nominal. Calculation details are in the profitability model and RoA explanatory note published alongside this report. The weighted averages are weighted by the RAB/CAB of each NSP.

The lower RoA by electricity NSPs' is primarily attributable to:

- Revenue differences (-0.4 p.p). Electricity NSPs can experience revenue differences for several reasons, including temporarily recovering higher or lower revenue than targeted through the revenue cap, the impacts of revenue smoothing, changes in the annual revenue target to account for past over-or-under recoveries in previous regulatory periods and the revenue from approved cost pass throughs.

- Under recovery of revenues from pass through transmission costs and jurisdictional schemes (-0.2 p.p). Returns from pass throughs occur when the electricity DNSP has higher or lower payments for transmission and jurisdictional charges, that they receive from the transmission and jurisdiction components of network revenue. The impact of pass through revenues on the profitability measures will balance out over time.

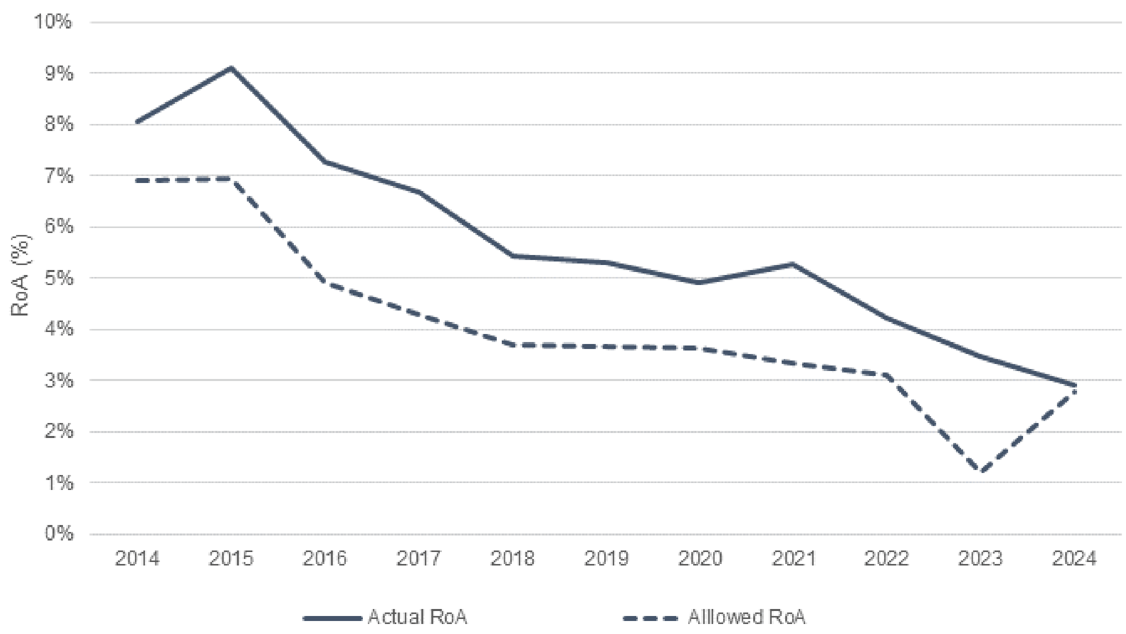
This was partially offset by incentive scheme rewards from prior regulatory years (0.3 p.p) applied in their 2024 revenues.

5.1.2 Gas DNSPs have returns marginally above allowed returns

In 2024 gas DNSPs had a decrease in their RoA returns (0.6 p.p) and continued the gradual decrease of RoA throughout our dataset. On average, gas DNSPs had returns that were insignificantly different to their allowed returns (0.1 p.p), with the difference narrowing from 2023.[118]

This result is in contrast to what was reported in our 2023 report, when we had to rely on annualising 6 months of data for the Victorian gas DNSPs. It is evident that this distorted the results, as can be seen in Figure 5-2.

Figure 5-2 Real RoA compared to allowed real RoA - gas DNSPs



Source and Note: Refer to Figure 5-1.

118 Due to the expected inflation for the six-month transitional extension to the 2018-22 access arrangement period (January to June 2023) being 3.08%, the nominal pre-tax allowed returns for the Victorian gas DNSPs which ranged from 2.82% to 3% were converted into real per-tax allowed returns which ranged from -0.25% to -.07%. These numbers were annualised to account for the six-month regulatory year and has resulted in the lower allowed returns and distorted higher returns in 2023.

The decrease in RoA was driven by

- opex efficiency (0.5 p.p): Opex efficiency returns occur when gas DNSPs' actual opex incurred is below the opex allowance included in the gas DNSPs access arrangement.
- incentive scheme rewards (0.1 p.p) from prior regulatory years.

The impact of these drivers was offset by the revenue differences (-0.5 p.p). For gas DNSPs, revenue differences can occur from the impacts of revenue smoothing, revenue adjustments from previous access arrangements and lower revenues earnt under the weighted average price cap.[119]

5.2 EBIT per customer continues to decrease

EBIT per customer is a measure of an NSP's operating profit divided by its customer base.[120] This measure complements the RoA by using the same measure of profit (EBIT) over a different cost driver. EBIT per customer is not a calculation of the EBIT per residential customer. It is an average of the entirety of an NSP's customer base, including businesses and large customers who contribute substantially more revenue per customer.

This follows the same trend as the RoA, with lower EBITs and growing customer bases resulting in lower EBIT per customer across all sectors and segments.

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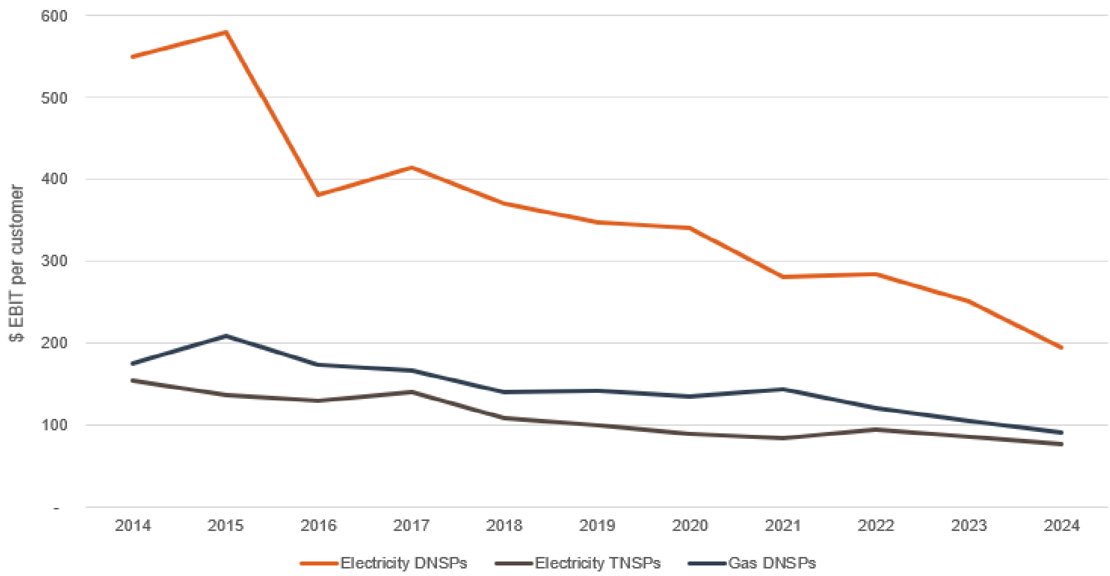
119 Refer to section 4.2 for a discission of weighted average price caps.

120 The customer base for electricity TNSPs is the sum of direct-connect customers and the distribution customers located in the same region as the electricity TNSPs.

Figure 5-3 Real EBIT per customer - electricity DNSPs and TNSPs and gas DNSPs



Source: Electricity and gas financial performance models.
Note: Financial performance numbers are nominal. Calculation details are in the financial performance model and EBIT per customer explanatory note. The weighted averages are weighted by the customer base of the electricity NSPs and gas DNSPs.

The EBIT per customers for electricity TNSPs and gas DNSPs are materially lower than for electricity DNSPs. This is a consequence of the higher capital intensiveness of electricity distribution networks, resulting in electricity DNSPs having larger RABs per customer. However, it does not mean than electricity TNSPs or gas DNSPs are less profitable in relation to the same levels of investment.

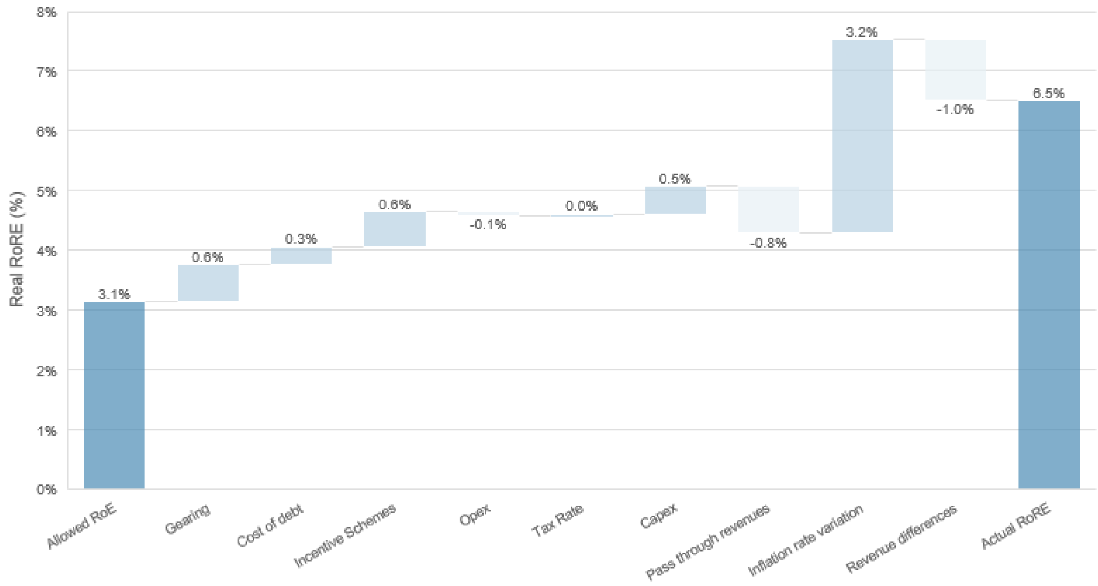
5.3 RoRE returns decrease as inflation eased in 2024

The RoRE is the net profit after tax (NPAT) divided by the NSP's regulated equity. As NPAT is the final or ultimate return to an NSP's equity holders, it captures the 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 differences between actual and forecast tax and interest expense can be heavily impacted by the external environment. Changes to tax policy, as well as interest and inflation rates can result in NSP's RoRE differing from their return on equity allowance.

In 2024, on a combined weighted basis, electricity NSPs and gas DNSPs had returns higher than their allowed returns. The primary driver remained inflation rate variation (3.2 p.p), as for most electricity NSPs and gas DNSPs, actual inflation applied was 4.1%, above the AER's expected inflation of 2.5%.

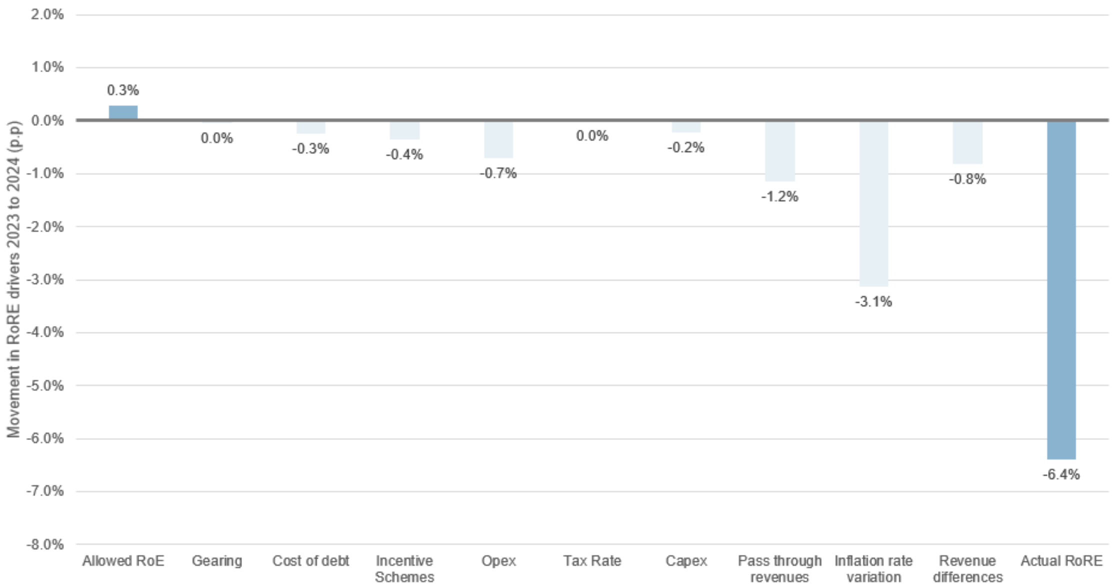
Figure 5-4 Contributions to real RoRE - electricity NSPs and gas DNSPs - 2024



Source: PTRM and electricity and gas DNSP financial performance models (confidential versions).
Note: Financial performance numbers are nominal. AER calculation of the differences in the RoRE is for indicative purposes and involves substituting actuals for each driver for the AER benchmark allowances. In this methodology, the contribution of each driver to the RoRE are impacted by the driver's sequence of substitution. We calculate the incremental change in returns with each new factor for each electricity NSP and gas DNSP and take a weighted average across all electricity NSPs and gas DNSPs.

Despite returns being higher than allowed, when compared to 2023 on a weighted combined basis, electricity NSPs and gas DNSPs had lower returns from each RoRE driver. This has led to the total actual RoRE decreasing by 6.4 p.p in 2024, despite allowed returns increasing by 0.3 p.p.

Figure 5-5 RoRE drivers - electricity NSPs and gas DNSPs - 2023 to 2024



Source: PTRM and electricity and gas DNSP financial performance models (confidential versions).
Note: Refer to notes for Figure 5-4.

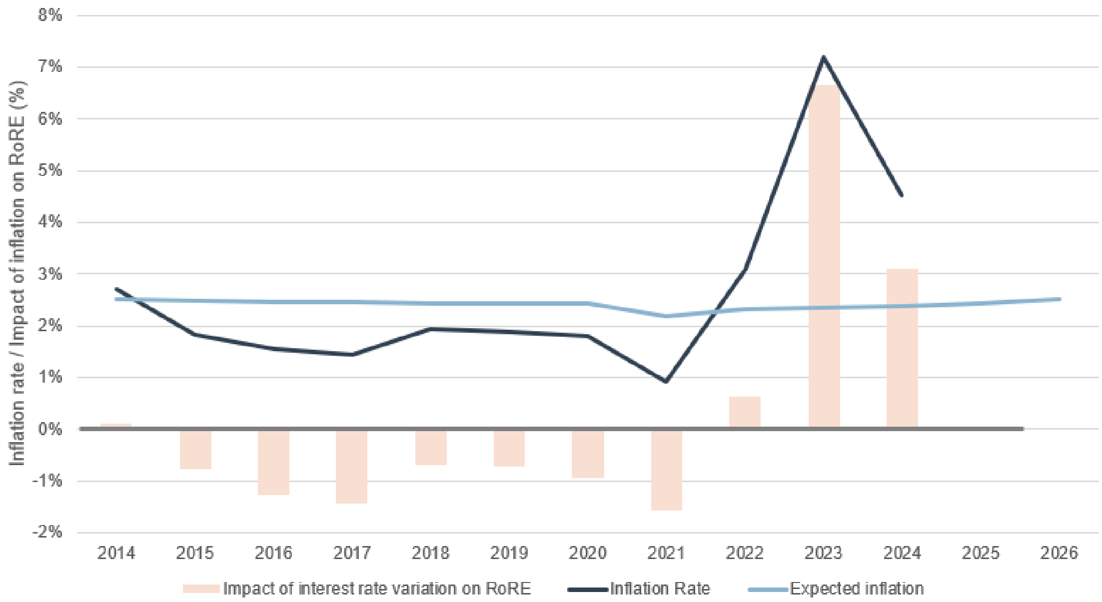
5.3.1 How does inflation impact RoRE

Our 2024 report provided extensive discussion in relation to the impact of inflation and how the calculation and interpretation of RoRE is bespoke to our regulatory framework.

The operation of the framework involves NSPs bearing the risk from actual inflation differing from expected inflation, as it is a more efficient allocation of risk. NSPs have greater resources or ability than consumers to mitigate against variations from expected inflation. As NSPs bear the risk from inflation, there will higher returns for NSPs when inflation is higher than expected, and lower returns when inflation is lower than expected.

There has been a recent shift from a very low to materially higher inflation rate environment, contributing to higher RoRE achieved by networks. Figure 5-6 illustrates how this shift affected the actual inflation rate applied to index electricity NSPs' RABs on average. It also shows how actual inflation as measured by the Consumer Price Index (CPI) diverged from regulatory forecasts and the effect this had on real RoRE since 2014.

Figure 5-6 Impact on real RoRE from inflation rate variation - electricity NSPs



Source: Electricity financial performance model and expected inflation from Electricity NSPs regulatory determinations.

The high inflation rate environment from 2022 to 2024 has led to RoRE returns being significantly higher than allowed returns, which was most noticeable in 2023. As inflation decreases in the 2025 regulatory year, we expect the returns from inflation rate variation to also decrease.

5.3.2 RoRE returns may not reflect actual network's profits or cash flows received

Our RoRE calculation methodology is necessary to compare the outturn RoRE against the allowed returns on equity included in our regulatory determinations and access arrangement. However, there are factors which result in the RoRE not resembling the profit to an NSP's equity holders which increases the equity in their business or the cash available for disbursement.

In the 2022 to 2024 regulatory years, the higher inflation will result in higher cash flows in the future through the return on capital and return of capital building blocks in future regulatory determinations and access arrangements. These higher returns due to inflation could be seen as similar to 'unrealised gains' on assets, as the NSPs did not receive increased cash flows which could be distributed to their equity holders.

Other factors which may not result in the RoRE not resembling profit or cash flows includes:

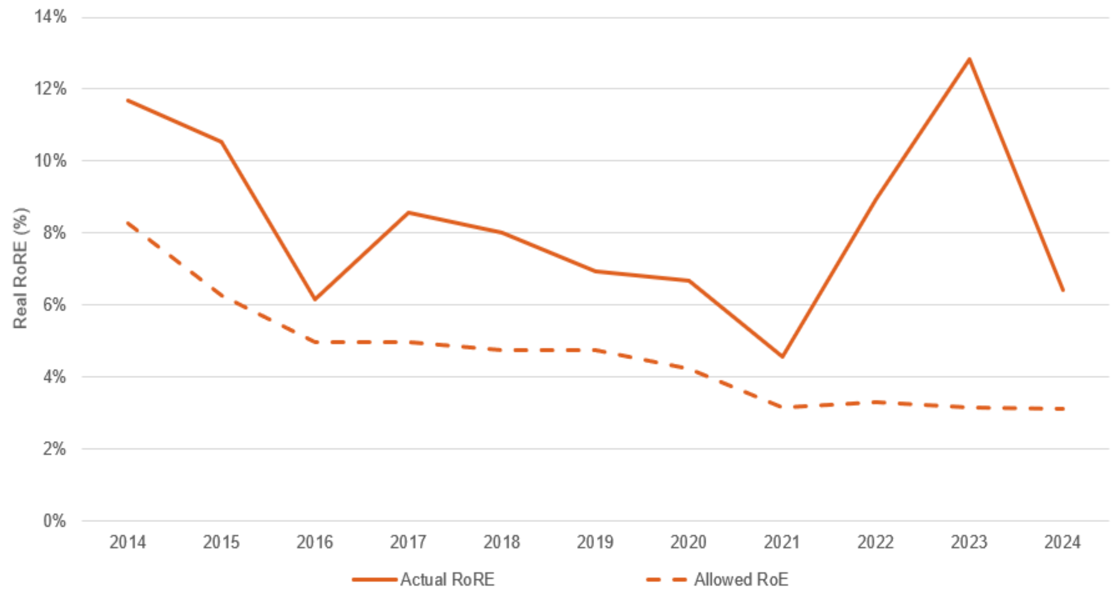
- the use of the RAB/CAB, indexation of interest-bearing liabilities and returns arising from imputation credits to calculate an NSP's returns, which are not traditionally used to determine a business's return of equity in broader competitive markets.
- the calculation methodology to determine the RoRE differing in certain aspects from the financial reporting requirements under the respective accounting standards.

These limitations are due to our regulatory framework being designed to compensate NSPs for efficiently incurred costs and therefore their allowed rate of return, which involves EBIT and not NPAT.

5.3.3 Electricity RoRE decreases due to lower inflation

When compared to 2023, the weighted average electricity NSP RoRE decreased by 6.9 p.p, reducing the difference from the allowed returns to 3.3 p.p.

Figure 5-7 Real RoRE versus allowed RoE - electricity NSPs



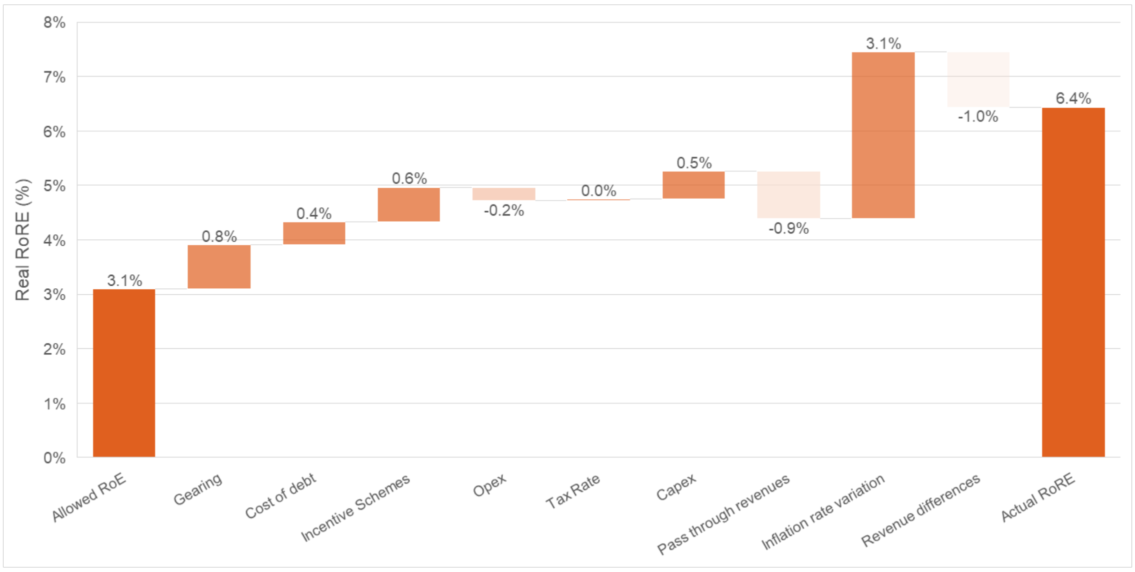
Source: Electricity financial performance model
Note: Financial performance numbers are nominal. The weighted average RoRE is calculated by multiplying an NSP's real RoRE against the proportional size of the NSPs' sectors regulated equity.

Inflation was the primary contributor to the 2024 RoRE being higher than the electricity NSPs' allowed returns and lower than the weighted average RoRE in 2023. This is due to inflation rate variation contributing 3.1 p.p to the actual RoRE in 2024, a decrease from the 6.7 p.p contribution in 2023.

Similar to 2023, electricity NSPs had higher returns from the different gearing in their capital structures (0.8 p.p), lower cost of debt (0.4 p.p) and revenues from incentive schemes (0.6

p.p), however the returns from these drivers were lower than last year. These were offset by the impact of pass-through revenues and revenue differences (combined 1.9 p.p) and the combined opex inefficiency of electricity NSPs (0.2 p.p).

Figure 5-8 Contributions to real RoRE - electricity NSPs - 2024



Source: PTRM and electricity financial performance model (confidential version).
Note: Refer to notes for Figure 5-4.

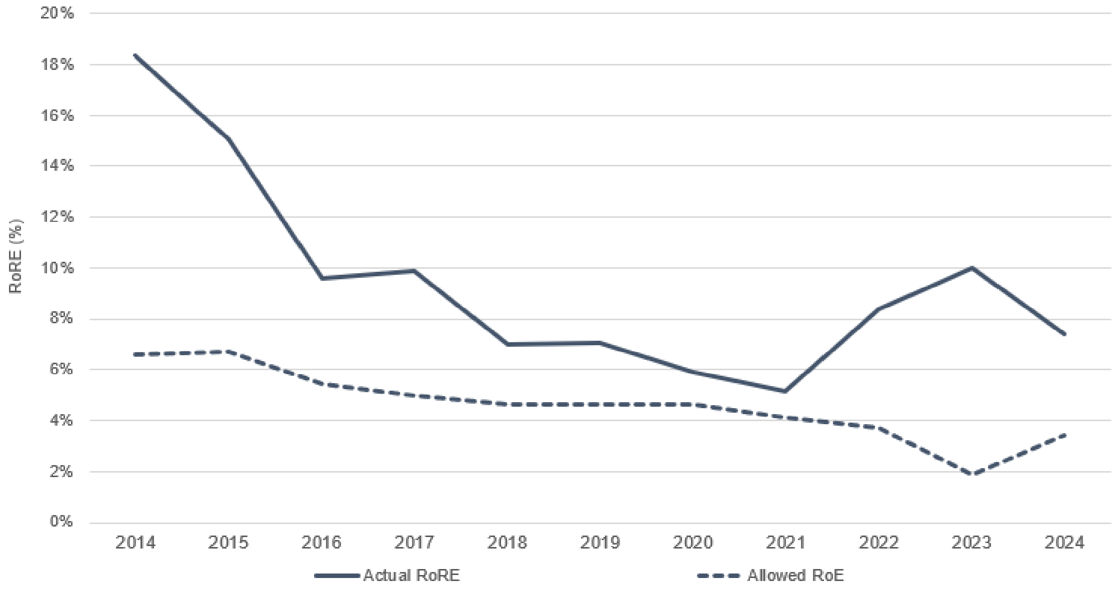
With annual inflation in the December 2024 quarter decreasing to 2.4% from the December 2023 quarter annual inflation of 4.1%, inflation should have minimal impact on most NSPs' RoRE next year.[121] However, this will be offset by the Victorian electricity DNSPs applying their 4.1% inflation on an 18-month lag to calculate their 2025 RoRE.

5.3.4 Gas DNSPs' RoRE returns decrease

When compared to 2023, the weighted average gas DNSPs RoRE decreased by approximately 2.5 p.p, whilst the difference between actual and allowed returns decreased to 4 p.p.

121 Both inflation rates are sourced from the Australian Bureau of Statistics (ABS).

Figure 5-9 Real RoRE versus allowed RoE - gas DNSPs



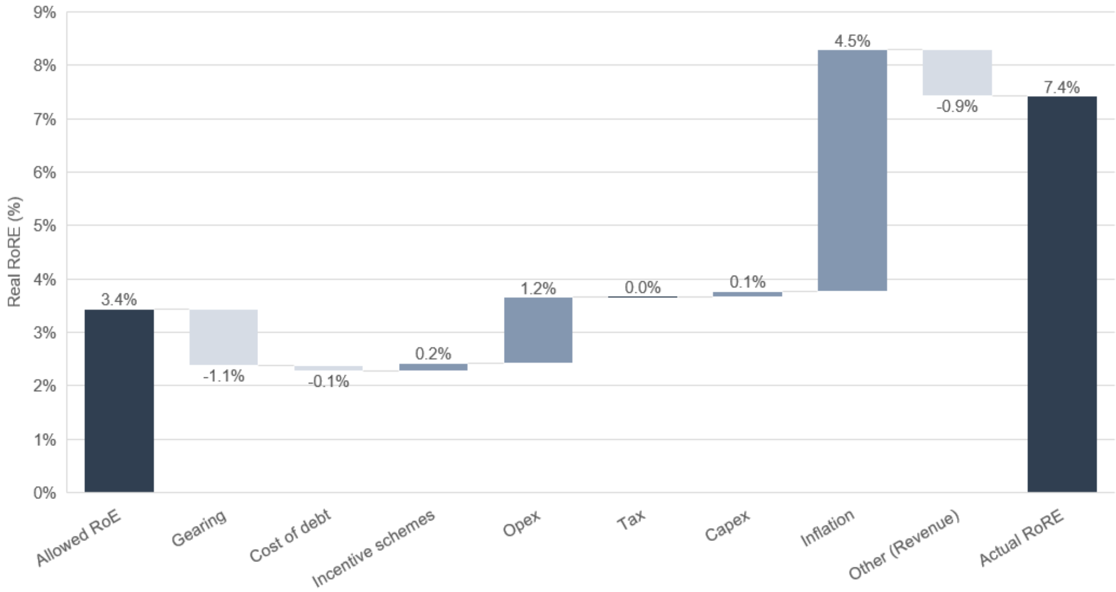
Source: Gas DNSP financial performance model.
Note: Refer to Figure 5-7.

The decrease in returns, is due to a specific one-off revenue adjustment for Victorian gas DNSPs associated with their six-month transitional access arrangement, which artificially increased their 2023 RoRE returns (-5.8 p.p), and lower revenue adjustments (-0.5 p.p) and opex efficiency (-0.4 p.p). This was offset by higher allowed returns (1.6 p.p) and higher returns from inflation rate variation (1.7 p.p).

The higher inflation returns for gas DNSPs in 2024 was due to the 18-month lag in applying an inflation rate of 7.8% to Victorian gas DNSPs', rather than the inflation rate of 4.1%[122] (which was applied to Evoenergy, Jemena Gas Networks and AGN South Australia).

[122] These inflation rates are based on the annual inflation rates for the 2022 and 2023 December quarters.

Figure 5-10 Contributions to real RoRE - gas DNSPs - 2024



Source: PTRM and gas DNSP financial performance model (confidential version).
Note: Refer to notes for Figure 5-4.

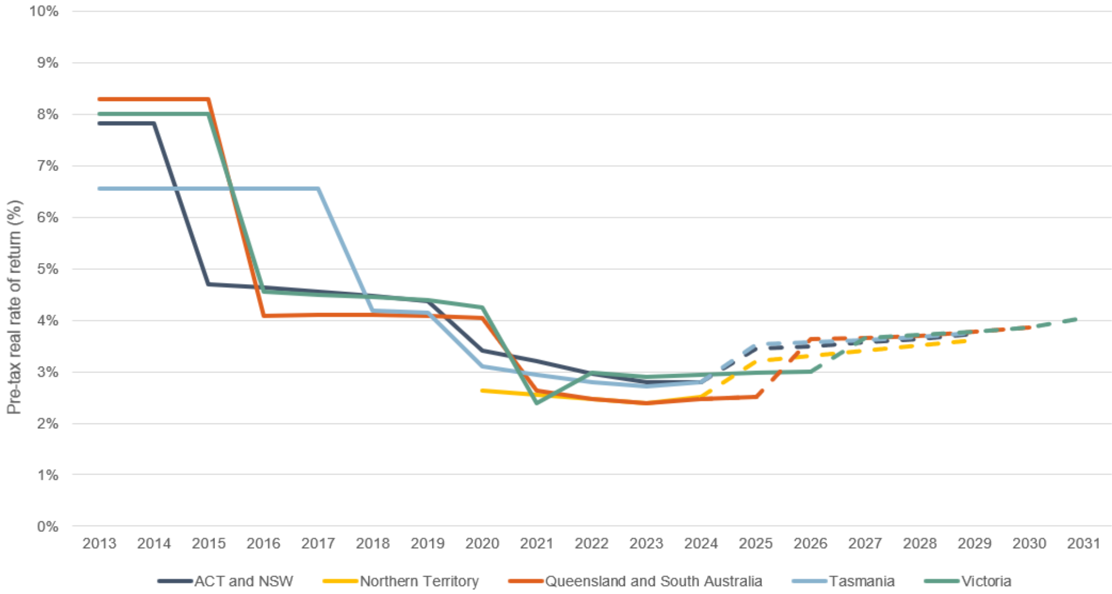
Similar to electricity NSPs, we expect the inflation rate variation to decrease in 2025, as Victorian DNSPs have 4.1% inflation applied to their returns, and Evoenergy, Jemena Gas Networks and AGN South Australia have 2.4% inflation. This will likely lead to lower overall RoRE returns for gas DNSPs in 2025.

5.4 Outlook for future allowed returns

Our financial performance data largely spans the periods in which the lower rates of return were applied in an NSP's regulatory determination and access arrangement. As detailed above, this has led to lower revenues, both in total and on a per customer basis.

An NSP's rate of return comprises of their return on equity and their return on debt. The return on equity is determined “on the day” of the regulatory determination and remains constant across an NSP's regulatory period, whilst their return on debt is updated annually.

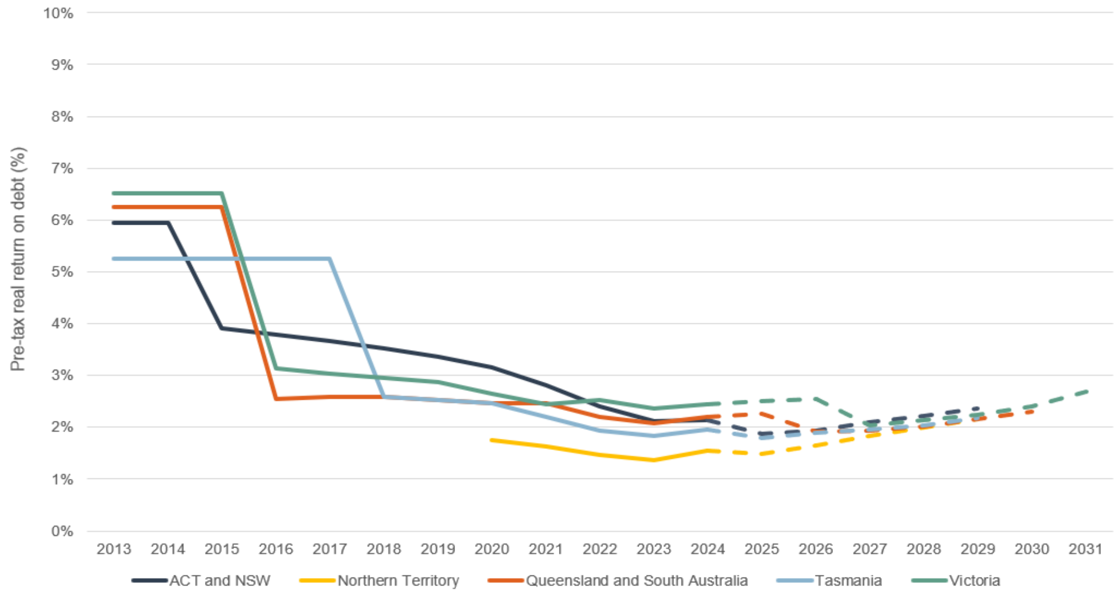
Figure 5-11 Allowed rate of return - electricity DNSPs



Source: Allowed real rate of return - PTRM 'WACC' sheet.
Note: Allowed rate of return post 2024 denoted with dashed line. Victorian DNSP pre-tax real WACC is from their draft decisions for their 2026-31 regulatory control period.

Unlike returns for equity, the return on debt is progressively updated for any changes in an NSP's debt costs. The difference in timing between returns for equity and debt reduces the sensitivity of the rate of return to changes in debt markets between regulatory determinations. For consumers, this means the recent decrease in interest rates will not be experienced immediately, but rather gradually implemented in their network costs using a trailing average approach across a 10-year period.

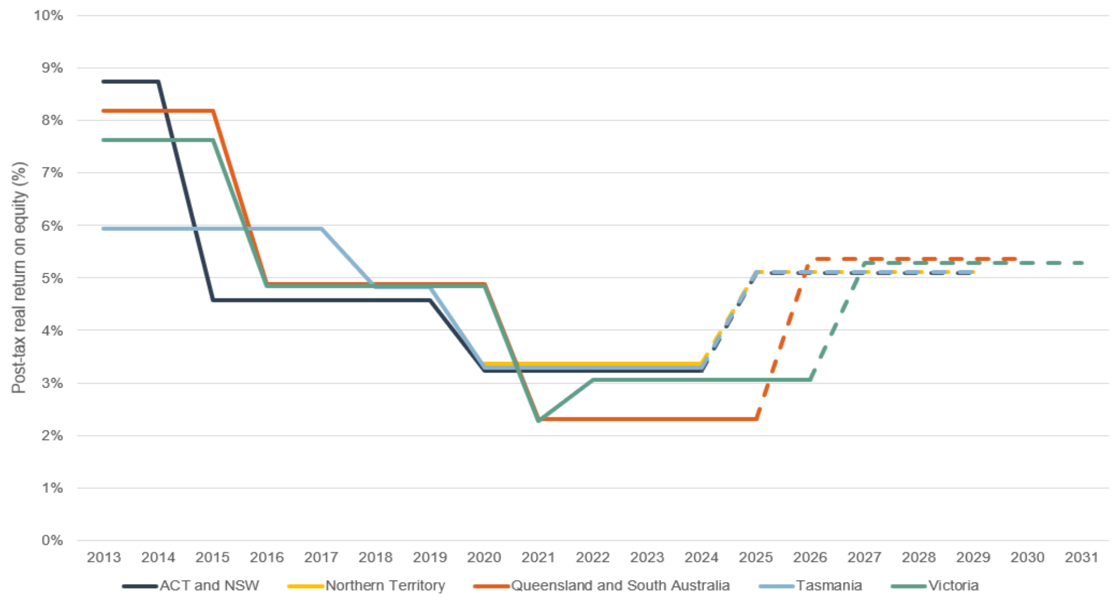
Figure 5-12 Pre-tax real return on debt - electricity DNSPs



Source: Allowed pre-tax real return on debt - PTRM 'WACC' sheet.
Note: Allowed pre-tax real return on debt post 2024 denoted with dashed line. Victorian DNSPs pre-tax real return of debt is from their draft decisions for their 2026-31 regulatory control period.

In contrast, as noted with the recent determinations for all non-Victorian electricity DNSPs, changes in the required return in the capital and financial markets for an investment of similar risk are immediately reflected in an NSP's return on equity.

Figure 5-13 Post-tax real return on equity - electricity DNSPs



Source: Post-tax real return on equity - PTRM 'WACC' sheet.
Note: Allowed pre-tax real return on equity post 2024 denoted with dashed line. Victorian DNSPs pre-tax real return on equity is from their draft decisions for their 2026-31 regulatory control period.

Although higher returns on equity will increase the allowed rate of returns, its impact will be limited by the return on debt being updated over a 10-year period. This prevents any significant step change in an NSP's rate of return and an NSP's forecast revenues from changes in the external environment between regulatory determinations.

6 Glossary

Term	Definition
Access arrangement	An arrangement setting out the terms and conditions of access to pipeline services
AEMO	Australian Energy Market Operator - manages the National Electricity Market (NEM) and the retail and wholesale gas markets of eastern and southern Australia and oversees system security of the NEM electricity grid and the Victorian gas transmission network. AEMO is also responsible for national transmission planning and the operation of the Short-Term Trading Market (STTMs) for gas
Allowed revenue	The allowed revenue represents the total amount of money an NSP is permitted to collect from customers during a specific regulatory period
Building Block Model	The model used by the AER to determine the revenue requirements for NSPs. This model encompasses five components: return on capital, regulatory depreciation, opex, incentive mechanism, and corporate income tax
Core regulated services	Standard Control Services for electricity DNSPs and prescribed Transmission Services for electricity TNSPs. Haulage reference services and ancillary reference services for gas DNSPs, reference services and other services provided as a covered pipeline for gas TNSPs
Cost pass through	A cost pass through event refers to a situation that occurs beyond the reasonable control of a network business and has not been accounted for in its current 5-year revenue determination
CPI	Consumer Price Index
DMIAM	Demand management innovation allowance mechanism
ESC	Essential Services Commission of Victoria - Independent regulator established in 2001 to regulate Victoria’s energy, water, and transport sectors, and administer the rate-capping system for the local government sector
Export	Electrical energy that flows from a customer's premises to a distribution network via the connection point
Gearing	The ratio of the value of debt to total capital (which includes both debt and equity)
Indexation	Adjustment made to nominal values of an asset, revenue, or expenditure, so that the amounts reflect inflation rate changes
LFiT	Large-scale Feed-in Tariff
NEL/NER	National Electricity Law (NEL) and National Energy Rules (NER) govern the operation of the NEM. The NEL is contained in a Schedule to the National Electricity (South Australia) Act 1996. The NEL is applied as law in each participating jurisdiction of the NEM by application statutes

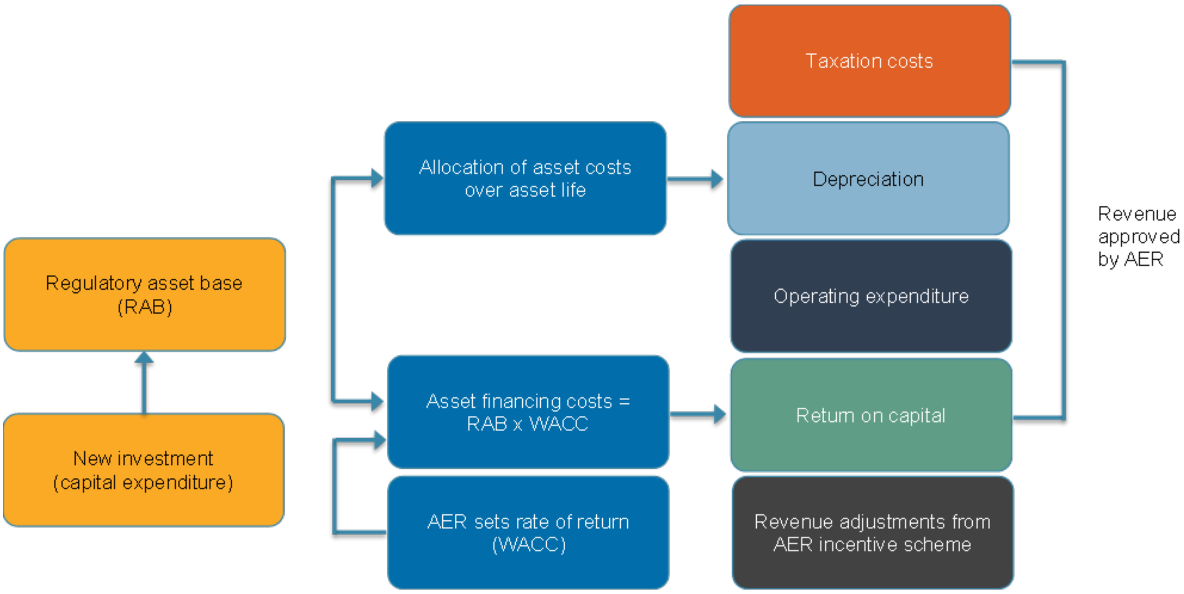
Term	Definition
	Changes to the NER are made by the AEMC.
NEM	National Electricity Market - operating in NSW, Queensland, South Australia, Victoria, Tasmania and the ACT, the NEM is both a wholesale electricity market and the physical power system
Network utilisation	Network utilisation measures the extent that network assets are used to meet customer demand
NGL/NGR	The National Gas Law (NGL) and the National Gas Rules (NGR) bring responsibility for regulation of access to natural gas pipeline services provided by transmission and distribution pipelines under the national energy market framework.
Nominal terms	Values expressed in current monetary units, without accounting for changes due to inflation or other factors
PTRM	Post-Tax Revenue Model - used as part of the building block determinations for NSPs. It is used to calculate the allowed revenue for a given regulatory period.
Real terms	Values that have been adjusted for inflation
Regulatory determination	A determination of the maximum revenue an electricity NSP can recover from customers for the use of their electricity distribution or transmission networks during the regulatory period.
Reliability	The frequency and duration of interruptions to customer supply
RFM	Roll-Forward Model - establishes the method used to roll forward the capital base (increase or decrease from the previous value)
RIN	Regulatory Information Notice - AER employs RINs to collects information from regulated businesses to undertake its functions
SIB capex	‘Stay in business’ capex
Tariff variation model	The AER employs a tariff variation model to manage changes in reference tariffs for energy services. Each year, gas DNSPs submit tariff variation notices to the AER for approval
WACC (or allowed returns)	Weighted Average Cost of Capital - the overall cost of financing a company’s operations and investments, balancing equity, and debt considerations
X-factor	The X-factor is used with CPI to smooth the revenue an NSP will collect each regulatory year. This X-factor is an input in the control formula applied in annual pricing and is the change in real revenue/price from year-to-year. The X-factor is updated annually for changes in the allowed return on debt

Appendix A: How are network revenues determined?

We set the maximum allowed revenue for electricity NSPs and price caps for gas NSPs at a level that allows NSPs to recover the costs of providing their core regulated services. These are referred to as 'building blocks.' The building blocks include:

- **return on capital** - a return on the RAB or CAB to compensate investors for the opportunity cost of funds invested in the NSP
- **return of capital (depreciation)** - which returns the initial investment in the RAB or CAB to investors over time
- **forecast operational expenditure** incurred providing network services
- the estimated cost of **corporate income tax**
- **revenue adjustments**, including revenue increments or decrements resulting from applying incentive schemes and other revenue adjustments

Figure A-1 The building block model to forecast revenue



Source: AER
Note: AER: Australian Energy Regulator. RAB: regulatory asset base. WACC: weighted average cost of capital.

For electricity and gas NSPs we update the target revenue each year to account for actual inflation, changes in the NSPs returns on debt, cost pass throughs and other factors.

Appendix B: Gas TNSP performance data

The gas transmission network service provider (TNSP) operational and financial performance datasets provide key operational and financial performance data for Amadeus Gas Pipeline (AGP), Roma Brisbane Pipeline (RBP) and Victorian Transmission System (VTS)[123] for the 2024 regulatory year. This is the period between:

- 1 July 2023 and 30 June 2024 for AGP and RBP
- 1 January 2024 and 31 December 2024 for VTS.

All financial values in these datasets are adjusted for inflation and provided in 30 June 2024 real dollar terms.

The data is sourced from annual regulatory information notices and roll forward models and post-tax revenue models from the gas TNSPs access arrangements, which are published on the AER website.

These datasets exclude confidential data. This ensures the confidentiality of commercially sensitive information is maintained while still providing the operational and financial data to assess the performance of the gas TNSPs.

B.1 Regulatory framework for AGP, RBP and VTS

These 3 gas TNSPs are the transmission pipelines which we regulate under 5-yearly access arrangements. These access arrangements use a building block approach to assess the TNSP's efficient costs and specify prices and reference services that must be provided to customers. The operational and financial performance of other scheme or non-scheme transmission pipelines are not included in this supplementary report.[124]

These 3 gas pipelines are regulated under the NGL and National Gas Rules (NGR) with the aim to promote efficient investment and operation of gas services for consumers' long-term interests. The AER employs an incentive-based weighted average price cap through access arrangement decisions. This approach, combined with performance monitoring, ensures the efficient and reliable delivery of gas transmission services to consumers at affordable prices.

B.2 Reference services and tariffs

AGP and RBP are regulated under weighted average price cap tariff variation mechanisms. This form of regulation provides for negotiations to occur between the operators of the gas TNSPs and transmission capacity users, known as "shippers".

For AGP and RBP, approved reference services and tariffs are reference points for those negotiations. Actual services and tariffs may vary from the reference services and tariffs we

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123 Information on the geographical location, injection and withdrawal locations and use of the gas for these TNSPs is provided in last year's Gas transmission network performance supplementary 2024.

124 The AER's reporting on scheme and non-scheme pipeline service reporting is provided in our Gas pipeline monitoring and transparency report 2025.

approve. This is expected and consistent with the regulatory framework and will result in these TNSPs possibly earning more revenue or incurring more costs.

While we expect negotiations may produce services and tariffs that vary from the reference services and tariffs we approve, the approved reference service must be available to shippers at no more than the approved reference tariff. The TNSP may charge less for a reference service but must not charge more than the approved reference tariff.

For VTS, reference services and tariffs are tightly defined with location-specific tariffs derived from a relatively complex and highly cost reflective tariff model. In this case, the reference services and tariffs we determine are the tariffs paid by shipper.

Appendix C: DMIAM outcomes in 2024

Our demand management innovation allowance mechanism (DMIAM) provides electricity DNSPs with funding for research and development in demand management projects that have the potential to reduce long term network costs.

The DMIAM applies to each electricity DNSP's eligible projects as set out in their regulatory determination. To receive the innovation allowance, the electricity DNSPs must report on their projects to us, including the:

- amount of the allowance spent,
- a list and description of each eligible project on which the allowance was spent, and
- a summary of how and why each eligible project complies with the project criteria.

For each eligible project completed in a regulatory year, electricity DNSPs must describe how the project will inform future demand management projects, including any lessons learnt. Lessons learnt may include demand management projects or techniques (either generally or in specific circumstances) that are unlikely to form technically or economically viable non-network options as well as successful projects and techniques.

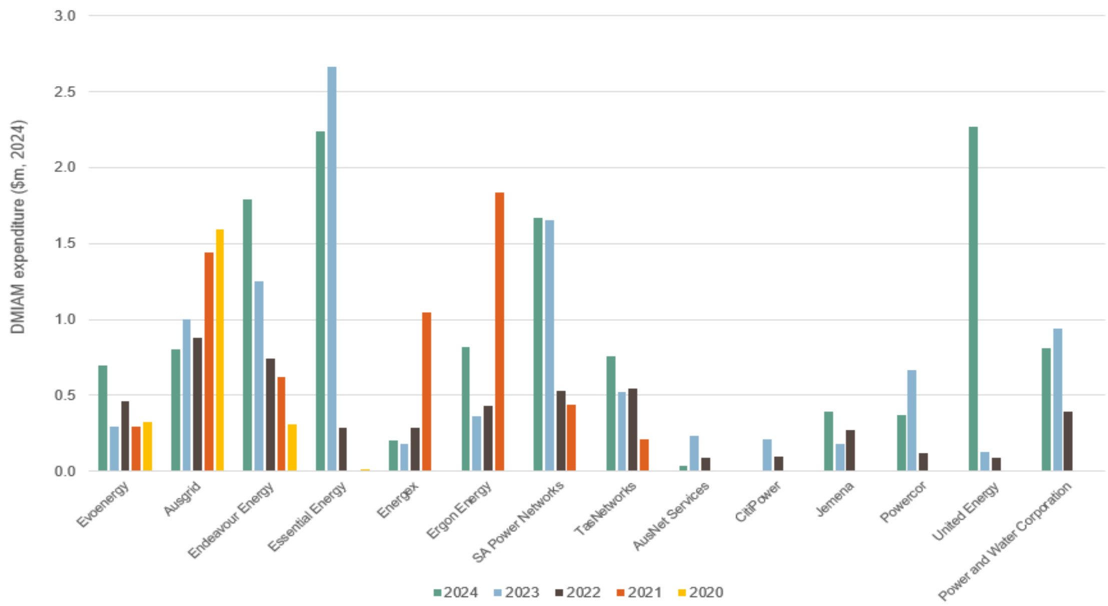
Electricity DNSPs must also provide any other information required to enable an informed reader to understand, evaluate, and potentially reproduce the demand management approach of an eligible project. A key objective of our DMIAM is to assist in enhancing industry knowledge of practical demand management projects through the annual publication of DMIAM activity reports from distributors.

Our DMIAM complements our demand management incentive scheme (DMIS) by increasing the capacity of distribution businesses to invest in ideas that may eventually form parts of projects under the DMIS.

C.1 DMIAM expenditures increased in 2024

The number of projects has declined, with 4% fewer projects in 2024 compared to the previous year. However, total project costs have increased by 32% year-on-year.

Figure C-1 Approved DMIAM expenditure - electricity DNSPs - 2020 to 2024

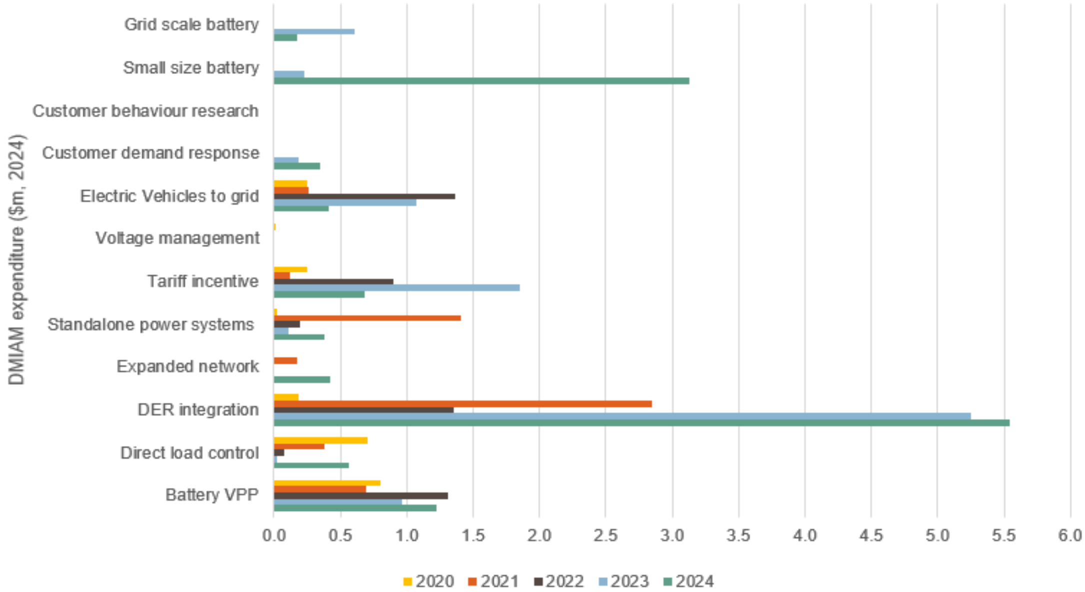


Source: AER analysis

C.2 DER and small size batteries most popular DMIAM projects

In 2024, distributed energy resources (DER) integration and small size battery were the most popular project types, with significantly more expenditure than any other project type. This is likely in response to the increasing installations of domestic and small commercial PV across the distribution networks.

Figure C-2 DMIAM expenditure by category - electricity DNSPs - 2020 to 2024



Source: AER analysis

Appendix D: Explanatory Note: RoA

This note explains our approach to reporting on the return on assets (RoA) for the NSPs we regulate. This note also explains factors to consider when interpreting RoA:

What is RoA?

RoA is a simple and commonly used ratio, indicating how profitable a company is relative to its total assets. RoA is suited to capital intensive businesses and allows us to compare NSPs' profits against their allowed rates of return. We calculate RoA using the following formula:

$$\text{ROA} = \frac{\text{EBIT}}{\text{Capital base}}$$

Where:

- EBIT is earnings before interest and tax
- Capital base is the value of the NSP's assets at the start of the regulatory year

How to interpret ROA

Our regulatory framework targets a real rate of return, compensating NSPs for actual inflation outcomes and preserving the purchasing power of NSPs and investors. To capture these two components of our framework, we report the:

- real rate of return, which excludes inflation and is compared against the real pre-tax rate of return
- nominal rate of return, which includes inflation and is compared against the nominal pre-tax rate of return

An NSP's RoA can be compared against:

- its allowed rate of return
- RoAs for other NSPs in the sector
- Australian and international regulated businesses where the RAB/CAB is valued on a similar basis to that of the NSP

It is difficult to compare an NSP's RoA directly to those of unregulated businesses. This is due to the unique characteristics of the RAB/CAB under the regulatory framework, and the resulting rules for regulatory accounting, which differ to statutory accounting requirements.

Factors contributing to differences between RoA and allowed rate of return

An NSP's returns can also temporarily deviate from its allowed rate of return each year due to the application of the regulatory framework.

Certain additional factors can affect how regulated revenues are recovered from customers in subsequent regulatory years and should be considered when interpreting the RoA. These additional factors are provided in Table D-1.

Table D-1 Factors contributing to differences between RoA and allowed rate of return

Factor	Sector	Details
NSW/ACT transitional decision and remittal	Electricity NSPs	Analysis for the NSW/ACT electricity DNSPs over the 2014-19 regulatory period should be interpreted with caution. Reported revenues for those years are not adjusted for: • the transitional decision in 2015, which set a higher revenue target than what was in the final regulatory determination. Revenues recovered in 2015 were therefore materially higher than in the final decision. This over recovery was returned to customers over the remainder of the regulatory period • our 2014-19 regulatory determinations, which NSPs appealed and were set aside. During the appeal period, we accepted undertakings by NSPs setting out how they would recover revenues for years 2017-2019. These undertakings resulted in NSPs collecting more revenue than what the final remittal decision provided. These NSPs are returning revenue over recovered from this process to customers in the 2019-24 regulatory period
Queensland solar bonus scheme	Electricity NSPs	During the 2010-15 regulatory period for Energex and Ergon Energy, we included forecast solar bonus scheme payments in the opex allowance. We included a pass through mechanism for any difference to be applied two years later during the annual pricing process. Uptake of this scheme materially exceeded forecasts. This resulted in substantial under recoveries during regulatory years 2014 and 2015, which were recovered through higher revenue targets in 2016 and 2017. In the 2015-20 regulatory period, solar bonus scheme amounts were recovered through a different mechanism (a jurisdictional scheme obligation). This fed into network costs as part of the annual pricing process. Due to the changing treatment of this scheme, the switch in our model to remove pass through events does not ‘zero out’ the scheme’s specific impacts as applied in the 2010-15 regulatory period. Returns in 2014 and 2015 therefore appear lower than they otherwise would and returns in 2016 and 2017 appear higher than they otherwise would.
LFiT (Large-scale Feed-in Tariff) jurisdictional scheme	Electricity NSPs	Evoenergy applied to the ACT Government to recover reasonable costs in relation to the LFiT jurisdictional scheme. As the applications occurs in the middle of the regulatory year, Evoenergy must use forecasts rather than actual expenditure. This can result in large over or under recoveries of jurisdictional revenue. Due to this, there has been substantial over and under recoveries of jurisdictional revenue in the period 2018 to 2024. As a result, when determining the ROA inclusive of jurisdictional schemes, the returns are higher and lower than they otherwise would. Although no longer a jurisdictional scheme pursuant to the NER, the LFiT scheme continues to operate, with recovery outside of the AER’s approved network prices in 2025 and 2026.

Factor	Sector	Details
JGN transitional decision and remittal process	Gas NSPs	Analysis for JGN over the past (2014 to 2020) and current (2020 to 2026) access arrangement periods should be interpreted with caution. Reported revenues for those years have not been adjusted for the following factors: • the over-recovery of revenue for their 2014 to 2020 access arrangement whilst JGN sought a review of the AER's determination under the limited merits review framework • the downwards adjustment of $169m following the remittal process. This reduces allowed revenues for the 2020 to 2026 access arrangement • the effect of multiple annual adjustments to account for movements in underlying price drivers being applied in 2020. This resulted in approximately a $26m increase to JGN's target revenue that year, which is not captured in their PTRM forecast.
Victorian gas DNSPs transitional regulatory year	Gas NSPs	The 2023 regulatory year for the Victorian gas DNSPs was only six months. This was due to the Victorian Government deciding to move the state's DNSPs access arrangement periods from a calendar year basis to a financial year basis, which required a six-month extension to their 2018-22 access arrangements. The revenue set for the extension period for the Victorian gas DNSPs involved extending their tariff prices from 2022 with an adjustment for inflation. This decision to maintain the tariff prices in real terms resulted in expected revenues for the Victorian DNSPs which were materially above the approved building block model. This resulted in the Victorian gas DNSPs achieving returns higher than they otherwise would in 2023, with an expectation that the returns from their 2023-28 access arrangement would be lower than they otherwise would.
Unaccounted for gas	Gas NSPs	Gas DNSPs in the ACT, NSW and South Australia are required to directly contract UAFG volumes. As a result, UAFG is included in their allowed opex, and therefore their revenue allowance in our access arrangement determinations. Victorian gas DNSPs operate under a slightly different framework. The ESC sets a benchmark rate of UAFG for each NSP, measured as UAFG divided by total gas delivered. Gas retailers are required to contract sufficient gas to cover customer consumption and the actual UAFG. If actual UAFG is greater than the benchmark, the NSP is required to compensate retailers for the UAFG exceeding the benchmark. Where actual UAFG is lower than the benchmark, retailers make reconciliation payments to the NSP. Benchmark levels of UAFG for 2018 to 2028 can be found in the ESC's 2017 (for 2018 to 2022) and 2022 (for 2023 to 2028) UAFG benchmark reviews.

Factor	Sector	Details
		Because UAFG is considered via the ESC's benchmark process, it is not considered in their access arrangement determinations, nor included in NSPs' opex forecasts.

How we calculate RoA

This section sets out our approach and data sources for calculating ROA. This approach aims for the best possible comparison of NSPs' actual returns against allowed returns on capital. We source data for calculating ROA from:

- the latest approved or proposed RFMs for the NSP
- the latest approved or proposed PTRMs for the NSP
- the NSP's annual data submissions, including through RINs

Revenue and expenditure

For electricity DNSPs and gas NSPs we source revenue and expenditure data from the income worksheet of the annual reporting RINs. For electricity TNSPs, we source that data from the disaggregated income statement of the annual regulatory accounts.

- data relating to electricity NSPs are standard control services for electricity DNSPs and prescribed transmission services for electricity TNSPs
- data relating to gas NSP's core regulated services are haulage reference services for gas DNSPs and reference services and other services provided as a covered pipeline services for gas TNSPs

Revenue excludes the following:

- capital contributions: These are not included in the RAB and are not used in to calculate returns in the regulatory framework
- interest income: This is excluded as it is not part of the regulatory framework
- profit from the sale of fixed assets: Disposals (gross proceeds from an asset's sale) are removed from the RAB/CAB. The value of disposals in any given year is not used to calculate returns for that year and is therefore excluded from our annual calculations
- Disposals, however, affect returns on capital in future years by reducing net capex added to the RAB/CAB. We capture this effect by using the actual opening RAB/CAB as the basis for calculating returns

Expenditure excludes the following:

- finance charges: These largely comprise interest payments on debt and are therefore excluded from RoA, which is based on EBIT
- impairment losses: These are not permitted by the regulatory framework
- losses from the sale of fixed assets are excluded as the NSP is compensated through return of capital (depreciation)

- for gas NSPs, disposals affect returns on capital in future years by reducing the net capex added to the CAB. We capture this effect by using the actual opening CAB when calculating returns

Electricity DNSPs, Ausgrid and Evoenergy are owners of dual function assets. These assets operate in parallel with TransGrid's transmission network and essentially perform a transmission function by supporting the main NSW transmission network. Revenue and expenditure associated with dual function assets are treated as standard control services for the relevant DNSPs.

Depreciation

We have reported depreciation using nominal straight-line depreciation, which is measured on an as-incurred basis for all NSPs.

Depreciation is sourced from the final decision RFM where available. Where this is unavailable, we use the most recent regulatory proposal (for electricity NSPs), access arrangement proposal (for gas DNSPs) or draft decision RFM. Where those models are unavailable, we source depreciation from the PTRM, updated for the Consumer Price Index (CPI) to reflect inflation where available.

RAB (electricity)

To allow comparisons between actual and expected returns, we use the opening RAB in calculating RoA. We have reported the RAB on an as-incurred basis for electricity NSPs.

The opening RAB is sourced from the final decision RFM where available. Where this is unavailable, we use the most recent regulatory proposal or draft decision RFM. Where those models are unavailable, we calculate a partially as-incurred RAB roll-forward using as-incurred capex reported in the annual RIN. This allows us to consistently report the opening RAB on an as-incurred basis.

The PTRM calculates the opening RAB using expected inflation. We have updated the opening RAB using actual inflation where available. When calculating real RoA, we inflate the opening RAB by CPI. This is because an NSP's returns on capital are calculated using the nominal rate of return (nominal pre-tax return on debt and nominal post-tax return on equity). Inflating the RAB by CPI ensures an NSP's returns, and RAB are in the same dollar terms. When calculating nominal RoA, inflating the RAB is not required. RAB indexation is included as part of an NSP's returns, compensating the NSP for actual inflation.

CAB (gas)

To allow for comparison between actual and expected returns, we use the opening CAB in calculating RoA. We report the CAB on an as-incurred basis for both gas NSPs.

The opening CAB is sourced from the final decision RFM where available. Where a final decision RFM is unavailable, we use the most recent access arrangement proposal or draft decision RFM. Where those models are unavailable, we source opening CAB values from the annual RINs. For gas TNSPs, we calculate the CAB on as-incurred basis. This entails using the as-incurred capex reported by the gas TNSPs in their annual RINs.

When calculating real RoA, we must inflate the opening CAB by CPI. This is because an NSP's returns on capital are calculated using the nominal rate of return (nominal pre-tax return on debt and nominal post-tax return on equity). Inflating the CAB by CPI ensures that an NSP's returns, and the CAB are in the same dollar terms. When calculating nominal RoA, inflating the CAB is not required. CAB indexation is part of the returns an NSP receives, compensating the NSP for actual inflation.

Indexation of the opening RAB/CAB

Indexation of the RAB/CAB is sourced from the final decision RFM where available. Where this is unavailable, we use the most recent regulatory proposal (for electricity NSPs), access arrangement proposal (for gas DNSPs) or draft decision RFM. Where those models are not available, we calculate indexation using CPI figures sourced from the Australian Bureau of Statistics.

Incentive scheme revenues and payments

Our regulatory framework provides electricity and gas NSPs with revenues or payments through targeted incentive schemes aimed at improving network efficiency and reliability for electricity networks and to improve efficiency of gas DNSP's network expenditure.

These schemes allow the businesses to earn revenue (payments) above (below) their allowed rate of return. Customers should ultimately benefit from these schemes through lower regulated prices and improved reliability. We have calculated RoA both with and without incentive scheme outcomes to show the impact of incentives on actual returns.

- for electricity NSPs, the revenues and payments from incentive schemes have been sourced from the revenue sheet of the EB RIN (table 3.1.3), with impacts of the CESS identified in the PTRM
- for gas NSPs, the revenues and payments from incentive schemes have been sourced from the revenue sheet of the annual RINs (table F3.6)

Annual updates

We will update RoA annually, using appropriate RFM data where available.

Appendix E: Explanatory Note: EBIT per customer

This note explains our approach to reporting on earnings before interest and tax (EBIT) per customer for the electricity NSPs and the gas DNSPs. It also explains what factors to consider when interpreting these ratios. We do not report EBIT per customer for gas TNSPs.

What is EBIT per customer

EBIT per customer is a simple ratio of an electricity NSP or a gas NSP's reported EBIT over the total reported number of customers connected to its network in a year. EBIT per customer differs from other profitability measures that rely on asset or equity values and provides an alternative perspective on the drivers of operational profit margins.

$$\text{EBIT per customer} = \frac{\text{EBIT}}{\text{Customer Numbers}}$$

Where:

- EBIT is earnings before interest and tax in a year
- customer numbers - These are sourced for electricity and gas as per the approach specified at the end of this note.

How to interpret EBIT per customer

EBIT per customer is best compared against the individual electricity NSP or gas DNSP's past performance. This comparison will track changes in the measure through time to identify drivers of variation in returns, such as variations in the RAB or CAB or allowed returns.

EBIT per customer is not a measure of profit per residential customer, as electricity NSPs also provide energy and gas DNSPs gas to commercial and industrial customers. All these customer types contribute to the revenue collected, and to the costs of providing network services. Due to this, the electricity NSP and gas DNSP's individual customer profiles can materially affect the average profits it earns per customer.

Comparisons between NSPs

Differences in EBIT per customer among electricity NSPs and among gas DNSPs are largely explained by the size of their capital bases and customer numbers. Other factors that can influence EBIT per customer should be considered when interpreting this metric, which includes Customer profiles and those provided in Table D-1 of the RoA explanatory note.

Customer profiles

'Customer profile' refers to the composition of customers, including the type and size of customers it services.

- an electricity NSP's customer profile may be influenced by the geographical area it services as this can determine network size, topology, and customer density. We collect data on customers across the classifications of residential, small commercial and large scale commercial and industrial

- a gas DNSP's customer profile may also be influenced by the geographical area it services or whether industrial customers use the gas distribution network to transport gas. We collect data on customers across the classifications of residential, commercial, and industrial

For both electricity NSPs and gas DNSPs, generally, different classes of customers share the costs of providing network services. This makes it difficult to isolate the costs required to serve a particular customer or group of customers. It is therefore difficult to estimate EBIT per customer for the different customer classes. For example, when compared to residential customers, commercial or large-scale industrial users make up a small proportion of overall customer numbers but contribute a relatively high proportion to revenue given their higher energy consumption.

Holding other things constant, we would expect EBIT per customer for commercial and industrial users to be higher than EBIT per customer for residential customers.

How we calculate EBIT per customer

This section sets out our approach and data sources for calculating EBIT per customer. We source data for calculating EBIT per customer from:

- the latest approved or proposed RFMs
- the latest approved or proposed PTRMs
- the annual data submissions, including through annual RINs reported to the AER

Information on the revenue and expenditure, depreciation, incentive scheme revenues and payments to calculate EBIT is provided in the ROA explanatory note.

Customer Numbers

We source customer numbers from different datasets, according to their sector:

- electricity DNSPs: The STPIS reliability sheet of the annual RIN (Table 6.2.4)
- electricity TNSPs: Adding customer numbers from the electricity DNSPs connected to the electricity transmission network in the same jurisdiction; and customers connected directly to the transmission network (direct connections points). We source this data from the operational data worksheet of the EB RIN (Table 3.4.2)
- gas DNSPs: Are sourced from the customer number sheets (by type and tariff) of the annual RINs (Tables S1.1 and S1.2)

Annual updates

We will update EBIT per customer annually, using appropriate RFM data where available.

Appendix F: Explanatory Note: RoRE

This note explains our approach to reporting the return on regulated equity (RoRE) for the NSPs we regulate. It also explains factors to consider when interpreting RoRE.

What is RoRE?

RoRE is a measure of regulatory profitability. It is suited to capital intensive businesses and allows us to compare an NSP's profits against its allowed rate of return. We calculate RoRE using the following formula:

$$\text{RORE} = \frac{\text{Regulatory NPAT}}{\text{Regulated Equity}}$$

Where:

- regulatory NPAT is regulatory net profit after tax
- regulated equity is the implied value of equity in the RAB for electricity NSPs, and CAB for gas NSPs

How to interpret RoRE

Our regulatory framework targets a real rate of return. NSPs are also compensated for actual inflation outcomes, preserving the purchasing power of NSPs and investors. To capture these components of our framework, we report the:

- real RoE, which excludes inflation of the equity base and is compared against the real post-tax return on equity
- nominal RoE, which includes inflation of the equity base and is compared against the nominal post-tax return on equity

An NSP's RoRE can be compared against its relevant allowed return on equity, the RoE of other NSPs in the sector and Australian and international regulated businesses where the RAB/CAB is valued on a similar basis to that of the NSP

It is difficult to compare an NSP's RoRE directly to those of unregulated businesses. This is due to the unique characteristics of the RAB/CAB under the regulatory framework, and the resulting rules for regulatory accounting, which differ to statutory accounting requirements.

Common EBIT

Calculating RoRE begins with calculating earnings before interest and tax (EBIT). EBIT is also used to calculate RoA and EBIT per customer. All notes on interpreting the RoA and EBIT per customer are therefore also relevant to this measure.

Confidentiality

Unlike the RoA or EBIT per customer, we do not publish all RoRE calculations. Specifically, we do not publish interest and tax expense calculations used in moving from EBIT to regulatory NPAT. While the interest expense incurred in providing core regulated services may not be commercially sensitive, this information could be used to ‘back-out’ equivalent commercially sensitive information relating to unregulated business units.

To make the information and its outcomes as transparent as possible, we have published a full version of our RoRE model using illustrative data, allowing stakeholders to understand the calculation steps.

Factors causing differences between real and forecast RoE

Factors affecting RoA and EBIT per customer also affect the RoRE. RoRE is also affected by differences between forecast and actual financing structure, forecast and actual interest rates and forecast and actual taxation. These are discussed in Table D-1 and provided in more detail below.

Differences in financing structure

To finance investments in the RAB/CAB, NSPs raise capital through a mix of equity and debt. We forecast the rate of return using a benchmark proportion of capital raised through debt—also known as the gearing level. In practice, NSPs can depart from the benchmark. Holding other things constant, raising a higher proportion of capital through debt:

- increases interest expense, decreasing the RoRE
- reduces the equity base over which profits are distributed, increasing the RoRE

The net impact of these two effects depends on whether the NSP raises debt at interest rates above or below our forecast return on debt. In general, we find that raising more capital through debt (higher gearing) results in a higher RoRE. In effect, NSPs are taking on more risk to achieve higher returns on equity as they bear the risks, costs, and benefits of departing from the benchmark gearing level.

Differences in interest paid on debt

Our rate of return instrument includes a methodology for calculating interest rates at which a benchmark efficient NSP would raise debt—that is, the allowed return on debt. In practice, NSPs may raise debt at rates above or below our benchmark.

We calculate an effective portfolio interest rate using the interest expense and interest-bearing liabilities allocated to NSPs in providing core regulated services. These calculations are more reliable where debt is clearly allocated to specific NSPs. Some company groups that raise debt at the group level must apply an allocation method to estimate debt attributable to specific NSPs. Estimated data is inherently less reliable than observed data.

Differences in forecast and actual debt costs can have various drivers, including but not limited to NSPs:

- being perceived as having higher or lower default risk than our methodology implies
- raising debt at longer or shorter terms than our benchmark 10-year assumption
- raising debt in tranches departing from the assumed structure of debt raising under our trailing average portfolio return on debt
- accessing lower interest rates due to raising debt as part of a larger diversified ownership group

- raising debt over windows differing from our specified averaging periods over which forecast rates of return are calculated

Where NSPs raise debt at rates lower than their allowed return on debt, this contributes to a higher RoRE. If NSPs raise debt at rates higher than their allowed return on debt, it contributes to a lower RoRE.

Differences in tax expense

Under our post-tax framework, allowed revenue forecasts include an amount for expected tax payments. In practice, NSPs may pay a different amount of tax to this allowance.

Because we calculate actual tax paid at the NSP level within our model, tax expense varies in response to other changes in revenue or expenses. We also adopt different tax rates based on the reported company structure for tax purposes. Differences in this tax structure can contribute to differences between forecast and actual tax expense. We describe these in greater detail in the next section.

How we calculate RoRE

This section sets out our approach and data sources for calculating RoRE. This approach aims to facilitate the best possible comparison between RoRE and allowed returns on equity.

Data for calculating an NSP's RoRE comes from the following sources:

- the latest approved or proposed RFMs for the NSP
- the latest approved or proposed PTRMs for the NSP
- annual RIN submissions the NSP reported to the AER
- the NSP's response to an AER information request, which are to be included in a future Regulatory Information Order

Illustrative model

Alongside this note, we publish a version of our full model using illustrative data. We encourage stakeholders to explore this model for greater detail on the calculation steps involved in moving from EBIT to regulatory NPAT and the relationships between variables.

Overall methodology

Calculating the RoRE begins with EBIT as calculated for the RoA and EBIT per customer measure. We then:

- deduct interest expense arising from providing core regulated services—allocated by NSPs as part of their responses to our tax and interest information request
- deduct tax expense—calculated within the model as described below
- add returns arising from distributing imputation credits—using the benchmark value of imputation credits multiplied by tax expense

This gives us what we refer to as regulatory NPAT. To calculate RoRE we then divide regulatory NPAT by the equity base.

We calculate the equity base as the value of the opening RAB/CAB each year less the value of interest-bearing liabilities (debt) the NSP allocates as arising from providing core regulated services.

We also make a series of other adjustments depending on whether we are calculating a real or nominal RoRE. These are described in our profitability measures review and are set out in our illustrative model.

Interest expense

We regulate NSPs as individual networks. In practice, most NSPs are part of larger ownership groups. Commonly, debt is raised, and interest is accounted for at the ownership group level.

Estimating RoRE for an NSP requires an estimate of its interest expense in providing core regulated services at the network level. NSPs have allocated interest expense and the value of interest-bearing liabilities (i.e., how much debt gives rise to that interest expense) in providing core regulated services. In doing so, NSPs have used a top-down approach—that is, debt used in financing the RAB/CAB.

NSPs have used several approaches to do this, which they have specified in their responses to our information request. In the first year of our reporting, we engaged accounting firm PwC to assist us reviewing the first tranche of responses. A summary of their review is available on our website.

Tax expense

Like interest expense, tax expense is typically incurred at the ownership group level. However, unlike interest expense, the tax structure an NSP is held under affects its tax expense. This includes:

- entities taxed as companies. All gas NSPs currently fall under this category.
- National tax equivalency regime (NTER) entities
- government owned non-NTER entities
- flow-through entities

Flow-through ownership structures do not pay tax at the level of the NSP. Rather, the tax obligation passes through the partnership or trust to the ultimate tax paying entity, who pays tax at their applicable statutory tax rate. As identified in our tax review, this is the relevant level of tax for consideration as 'actuals'.

To undertake a top-down approach to tax, we would need the individual tax expenses across all owners of an NSP and individual allocations of the expense for each owner. As such, we consider tax expense is better suited to a bottom-up approach. This requires EBIT to be adjusted only for relevant differences for tax purposes, and to multiply this by an applicable tax rate. Our analysis has used the following tax rates in the relevant proportions:

- entities taxed as companies—30%
- NTER entities—30%
- government-owned non-NTER entities—30%

- flow-through entities—19.5%

We requested where available a weighted average of individual investors' tax rates. Where not available, we have applied an indicative rate of 19.5%. All NSPs have advised they were unable to develop a more detailed weighted average rate.

To calculate tax expense, we start with EBIT and then:

- deduct interest expense
- add back nominal straight-line depreciation
- deduct depreciation of the tax asset base, sourced from our RFM where available
- adjust for permanent differences due to disallowed interest expense and adjustments to prior returns
- add total taxable revenue and/or income from customer contributions and gifted assets

This provides an estimate of pre-tax income, which we then multiply by the tax rate described above. We then adjust for any tax-losses carried forward, which reduce the tax allowance. This gives our estimate of raw NPAT.

Imputation credits

The building block revenue framework recognises that imputation credits are a value stream available to equity holders alongside dividends and capital gains. We adjust the estimated cost of tax allowance for the value of imputation credits, which reduces the allowed revenue. By making an adjustment to the tax allowance, we avoid double counting the value of the imputation credits and forecast returns to equity/allowed returns to equity.

We make this adjustment by adding returns from imputation credits to our estimate of raw NPAT. We calculate these returns as the benchmark value of imputation credits (i.e., gamma) multiplied by tax expense after any utilisation of tax losses.

Calculating real versus nominal RoRE

Our model allows users to calculate either real or nominal RoRE. To calculate nominal RoRE, we add indexation of the RAB/CAB to our calculation of EBIT. Nominal RoRE should be compared against the equivalent post-tax nominal return on equity.

To calculate real RoRE, we remove indexation on the equity component of the RAB/CAB from our estimate of NPAT. We then inflate the equity base of the RAB to be in common real dollar terms with our estimate of NPAT. In our model, the real RoRE flows on from the real RoA, where we have already deducted indexation of both equity and debt. As a result, to work out the real RoRE, we must add back to our estimate of NPAT the indexation on the debt component of the RAB/CAB, which we have previously deducted.