2024 Electricity and gas networks performance report

September 2024

AUSTRALIAN ENERGY REGULATOR

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Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601
Email: aerinquiry@aer.gov.au
Tel: 1300 585 165

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Executive Summary

This is the AER's first combined annual Electricity and gas networks performance report, published in accordance with the National Electricity Law[1] (NEL) and National Gas Law[2] (NGL). This report replaces the previous separate electricity performance reports (published since 2020) and gas network performance reports (published since 2021). We have combined them to provide earlier analysis of gas distribution network service provider (DNSP) performance data to stakeholders and to enable the annual performance of electricity and gas networks in the 2023 regulatory year[3] to be considered together.

This report analyses the key outcomes and trends in the operational and financial performance of the 25 network service providers (NSPs) regulated by the AER under the National Electricity Objective (NEO) and National Gas Objective (NGO).[4] To the extent that 2023 is an inflexion point in the cycle of investment and financial performance, we make observations about the shifts from past trends.

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, no earlier than required, 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

Consumers pay lower networks costs and experience good reliability

In 2023, after adjusting for inflation (in real terms), electricity consumers on average paid the lowest cost for electricity network services since the beginning of our dataset. While after including inflation (in nominal terms) the average electricity network costs increased for consumers, it remains well below the 2015 peak. Further, gas distribution network consumers on average paid the lowest costs for gas distribution network services since the series began in 2011, both in real and nominal terms.

In addition to lower network costs, measured outages in both electricity and gas have been less frequent, and reliability performance is at a near all-time high.

These outcomes have been achieved primarily by two main factors, being network outperformance under incentive-based regulation and favourable conditions in the external

1 NEL, s 28V.

2 NGL, s 64.

3 In this report the 2023 regulatory year for NSPs is the period 1 July 2022 to 30 June 2023. The exceptions are AusNet Services (transmission) which has a regulatory year from 1 April 2022 to 31 March 2023 and Victorian gas DNSPs which are in transition from a calendar year to a financial year.

4 We report will report separately in the second half of 2024 on three scheme (transmission) pipelines (TNSPs): Amadeus Gas Pipeline, Roma Brisbane Pipeline and Victorian Transmission System, which operate on a different reporting schedule.

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. Since 2022 inflation has been rising and has subsequently led to rises in interest rates that will increase allowed rates of return and network costs in coming years.

Electricity network capex the highest since 2016

Capital expenditure (capex) for electricity networks increased by 19.7% in real terms in 2023, driven by overspends of capital allowances by NSW electricity distribution networks and Ergon Energy and capex on the EnergyConnect project (an Integrated System Plan (ISP) project) being reprofiled to 2023.

The capex investment by electricity NSPs in 2023 led to a slight increase in real terms in their cumulative regulatory asset base (RAB). We expect capex by electricity networks to increase in future years, and increase the RAB, as transmission networks undertake approved capex for future ISP projects, including EnergyConnect and Humelink.

Gas distribution CAB continues to decrease in real terms

Despite a 5% increase in real terms in capex investment, 2023 saw a cumulative decrease in the capital asset base (CAB) valuation in real terms for gas distribution networks.

Capex for gas distribution networks predominately relates to new connections and mains replacements of cast iron pipeline with polyethene or polyamide materials. Based on recent decisions by a number of state and territory governments to impose restrictions of new connections, we expect gas distribution network's capex to decrease in real terms in the future leading to further decreases in the CAB.

Further declines in CABs could also occur in the future through accelerated depreciation of network assets, which were considered in the recent 2023-28 access arrangement for Victorian gas distribution networks.

Networks achieve lower returns, but continue to outperform allowed returns

As the regulator of monopoly electricity and gas infrastructure we set an expected profit margin in line with a return for NSPs in capital or financial markets for an investment of similar risk. Our financial performance measures assess the financial performance of networks against these 'allowed returns' through three profitability measures.

Our best measure of the financial performance of networks and whether they have achieved the NEO and NGO is the return on assets (RoA) measure, which reports on whether networks have achieved operating profits[5] above their allowed returns.

Outperformance from this measure primarily occurs through capex, operating expenditure (opex) and incentive scheme outperformance, all of which are key features of our incentive based regulatory framework. Although networks benefit from higher operating profits, their

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5 This is earnings before interest and tax. It does not include interest or tax costs.

performance will also benefit consumers as efficiency gains flow through in the form of lower network costs in the future and improvement in service levels.

In 2023, electricity network and gas distribution networks had on average a lower RoA whilst also outperforming their allowed rate of return. This performance indicates that despite revenues falling, on average networks remained profitable and were able to provide sufficient operating profits to their equity holders.

Further decreases were also seen in the earnings before interest and tax (EBIT) per customer, a measure of operating profit per customer. This gradual trend of lower operating profits when compared to a network's customer base, is reflective of decreases in network revenues on a per customer basis.

Networks' return to equity holders may not be reflective of actual profits or cash returns

Although not impacting the RoA and EBIT per customer, inflation has significantly impacted the return on regulated equity (RoRE) profitability measure which reports on the final or ultimate returns to a network's equity holders, after subtracting a network's debt and taxation costs. This inflation has resulted in higher returns for electricity and gas, which reverses the trend observed between 2015 and 2021, when low inflation had a negative impact on network's RoRE.

In 2023, outperformance from actual inflation of 7.8% for most networks being higher than forecast of 2.3% should not be interpreted as "good financial performance" pursuant to the NEO or NGO. Rather, it is a function of our RoRE calculation methodology, which is designed to enable stakeholders to compare a network's costs to those allowed in their regulatory determinations and access arrangement and analyse what is contributing to a positive and negative impact on their returns.

This bespoke methodology is unique to our network regulation, which limits comparability to other returns of equity in broader competitive markets. This results in the inflation outperformance being seen as similar to unrealised gains or losses on assets, as it does not create cash flows available for disbursement to equity holders or a profit which increases the net asset position of their business.

Next year, we expect RoRE to decrease for electricity networks as the higher inflation in our methodology is replaced with the lower inflation to December 2023 of 4.1% for most networks. As indexation is applied on an 18-month lag for Victorian electricity and gas DNSPs, they will apply the 7.8% inflation in 2024.

Network utilisation will change with the energy transition

We traditionally consider network utilisation by comparing a network's peak maximum demand against the total capacity of its zone substation transformers. This measure has been relatively flat since 2014, with network utilisation in 2023 remaining consistent with previous years.

This measure does not account for two-way network flows and may not show localised constraints from exports from solar photovoltaic (PV) systems. As more consumers install solar PV systems, it increases the risk that DNSPs need to limit consumer energy resources (CER) being exported into the grid to protect network assets.

This is one of the ways that stakeholder's perceptions of how network assets are being used to provide distribution services are changing. One method to improve the use of network assets has been proposed in Energy Network Australia's The Time is Now report, which recommended that a smarter electricity distribution grid could unlock and enable more benefits for consumers.

The tag line for this report was that the distribution network can do more of the heavy lifting in the energy transition for consumers. As any new network infrastructure will be paid by consumers, it is imperative that we are effectively utilising our current infrastructure for distribution services, looking for non-network solutions and avoiding any unnecessary future infrastructure investment.

The rollout of smart meters will provide more network visibility to distribution networks, which will enable more granular and timely information to manage constraints on network assets. This is one of the potential data solutions which can be undertaken by networks to avoid unnecessary capital investment and lower network costs for consumers.

The impact of the energy transition is omnipresent in our reporting

The transition of the energy system to net zero emissions by 2050 and associated government policies is starting to impact network's revenues and expenditures, the valuation of network assets and energy transported or distributed through electricity and gas networks.

Specifically for gas distribution networks, there remains uncertainty over the immediate and longer-term impacts of emissions reduction targets and policy settings for residential uses of gas for heating and cooking. While gas distribution network customer numbers are currently stable, lower customer numbers in the future will increase a consumer's network costs as costs are shared over a smaller customer base. This will also lead to lower gas consumption, which may impact price stability and recovery of network revenues as well as increasing the likelihood of stranding of the gas distribution networks.

Changes in residential gas usage will also impact electricity demand as consumers progressively switch their household appliances from gas to electric. The extent to which this, and other factors like electric vehicle penetration, results in an increase in electricity demand and a greater need for augmentation or other network investment is uncertain. These factors increasing the amount of energy sourced from the grid required for maximum or peak demands in the future will also be dependent on improvements in appliance efficiency, installation rates of rooftop solar and battery storage, as well as the potential for shifts in consumer behaviour.

Electricity distribution networks will play a bigger role in the transition

AEMO's latest 2024 Integrated System Plan reiterated the required transmission infrastructure assets to transition to a net zero economy by 2050. Currently we are considering or have approved contingent project applications in relation to Project EnergyConnect, Eyre Peninsula Reinforcement, HumeLink, Queensland-NSW Interconnector Minor, Victoria to NSW Interconnector (VNI) Minor and VNI West.

A change from the draft version of the 2024 ISP was the greater recognition of the role that CER and electricity distribution networks will play in the energy transition. Distribution networks will need to host CER, and distributed utility-scale renewable and storage projects, to enable coordination of the two-way energy flows of electricity in the grid. This involves balancing supply and demand, managing the flow of electricity and optimising the use of CER, to benefit the owners of those assets as well as all consumers connected to the grid.

This envisions modernised electricity distribution networks connecting low-cost sources of energy to local communities, cities, and industry. Currently, distribution networks are beginning their transition, by managing their networks to coordinate CER and batteries provided by consumers exporting to the grid. This is a good start; however, any future progress requires the development of the role of a distribution system operator and the participation of CER in a range of services markets.

Some of these potential options for a modernised distribution network have been raised by Energy Networks Australia in their The Time is Now report. However, further work with stakeholders will be needed to determine the best method to incentivise distribution networks to become platforms for any new energy services. This collaboration with stakeholders will provide the best opportunity for new energy services to be efficient and deliver the best outcomes for all consumers.

1.2 Summary of 2023 Results

	Electricity	Gas distribution
Revenue	• Electricity network revenues of $12.5b represented in real terms a 2.9% decrease overall from 2022 equating to a decrease of $48 on a per customer basis. • Electricity revenues are significantly below their peak in 2015, when reductions in allowed returns on capital and specifically lower rates of return began to be applied in networks' regulatory determinations. • We expect revenues to increase in real terms in 2024 and in the following years due to higher inflation, equity returns and interest rates.	• Gas distribution revenues of $1.4b represented in real terms a 9.4% decrease overall from 2022, equating to a decrease of $36 on a per customer basis. Although impacted by annualising the Victorian gas distribution network data, in real terms, revenues are the lowest since 2011, driven by lower rates of return. • Higher Victorian gas distribution revenues in 2024 will increase revenues in real terms.
Financial performance	• Electricity networks had lower RoA in 2023 and outperformed their allowed returns. This has been driven by outperformance in relation to opex, capex and incentive scheme rewards from performance in previous regulatory periods. • This outperformance in relation to capex and opex will deliver benefits to consumers over the long term through lower network costs for consumers. • Inflation has significantly impacted the RoRE for electricity networks in 2023, resulting in higher returns for electricity networks. • This reverses the trend observed between 2015 and 2021, when low inflation resulted in lower RoRE. We expect the RoRE to decrease next year as annual inflation from the December 2023 quarter decreased from 7.8% to 4.1%.	• Gas distribution networks had lower RoA in 2023 and outperformed their allowed returns. Allowed returns decreased in 2023, due to Victorian gas distribution networks transitional six-month access arrangement. • This outperformance has been predominately driven by use of 2023 tariff prices in real terms for Victorian gas distribution networks and other revenue adjustments and opex outperformance. • Inflation has also impacted the RoRE for gas distribution networks, however at a smaller amount than electricity networks. • The impact of inflation will remain higher for gas distribution networks, as Victorian gas distribution networks index their CAB on an 18-month lag.

	Electricity	Gas distribution
Incentive schemes 	• Incentive scheme revenues increased significantly for electricity networks in 2023, with $633m of rewards from their performance in previous regulatory periods. • This was predominately achieved by distribution networks now receiving rewards from a capex-based incentive schemes in addition to the existing operating expenditure (opex) and reliability-based incentive schemes. • Incentive schemes are structured so that the overall benefits provided to consumers outweigh any revenues received by networks. This has enabled improved service levels, lower expenditures, and network costs for consumers.	• Gas distribution networks incurred small costs from underperforming against incentive scheme benchmarks in prior access arrangements.
Capex  	• Electricity networks had capex of $6.8b, a 19.7% increase in real terms from 2022. This was primarily driven by overspends of capital allowances by NSW electricity distribution networks, Ergon Energy and expenditure on project EnergyConnect being reprofiled to 2023. While this increase led to capex being above forecast for the first time since 2019, it remains significantly below its peak in 2012. • Forecast capex is approved as a total on a 5-year basis, and over this period, we expect that an electricity networks' capex will fluctuate between underspend and 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 had capex of $588m, an increase in real terms of 5% from 2022. • Gas distribution networks' capex is predominately related to new connections and mains replacements of cast iron pipeline for pipelines using polyethene or polyamide materials. The level of new connections and stage of mains replacements differs across gas distribution networks. • Based on recent decisions by a number of state and territory governments to impose restrictions of new connections, we expect capex from new connections to decrease in real terms in the future.

	Electricity	Gas distribution
Asset bases	• There was a slight increase in real terms in the RAB values for electricity networks in 2023. • This follows the trend since 2014, where on average the RAB has increased annually in real terms by 0.7%. • In future years we expect capital investments from the ISP, NSW Renewable Energy Zone (REZ), and contingent projects to increase transmission networks' RAB values.	• In 2023, cumulatively gas distribution networks had a decrease in real terms in their CAB values, with depreciation exceeding new investment. • This follows a trend for the past three regulatory years, where there has been an average 1.0% annual decrease in real terms in the CAB value. • In future years we expect CAB values to continue to decrease in real terms, as capital investment from new connections decreases amidst gas demand uncertainty and gas distribution networks depreciating existing network assets.
Opex	• Opex was $4.1b for electricity networks an increase of 4.1% in real terms since 2022. • Despite this, most electricity networks underspent their opex allowance for the regulatory year. • This outperformance and opex efficiency will lead to lower costs in future years, ultimately leading to lower network costs for consumers.	• Opex was $526m for gas distribution networks, an increase of 2.6% in real terms since 2022. • All gas distribution networks underspent on their opex allowance, which follows the previous six periods, where gas distribution networks have collectively underspent on their allowance.
Network reliability	• Network reliability across electricity networks remained high in 2023. • Reliability reasonably within electricity networks control was high, with the lowest number of outages in our dataset, and the duration of outages also decreasing. • This improved performance in 2023, reflects a gradual decrease in the number of outages customers experienced across our dataset and is the lowest duration of outages since 2020.	• Network reliability across gas distribution networks remained high in 2023, remaining infrequent and relatively rare for customers.

	Electricity	Gas distribution
Energy delivered	• Energy delivered by electricity distribution networks was 145 thousand GWh in 2023, an increase of 1.2% from 2022. • Despite this increase, energy delivered per residential customer has been largely consistent since 2018, at approximately 5.5 MWh per residential customer. • In future years we expect energy delivered by electricity networks to increase and gas demand to decrease as customers remove their gas connections and electrify their household appliances	• Gas demand of 270 thousand TJs in 2023 has been impacted by annualising the six-month regulatory year for Victorian gas distribution networks, where there was an overrepresentation of warmer months. • Because of policy developments toward net-zero on the future use of gas networks, there is uncertainty in relation to gas demand in future years.
Smart meters	• The rollout of smart meters will improve network visibility as it will provide more granular and timely information to electricity distribution networks and potentially consumers. • Smart meters continue to be rolled out in all states except Victoria, which completed its rollout in 2015. The next highest residential smart meter installation rate is in Tasmania (63%), with the other jurisdictions ranging from 35% to 40% of residential customers as of June 2023. • Following the Australian Energy Market Commission’s review into the regulatory framework for metering, the rollout is targeted to be completed by 2030, leading to more retail pricing options for consumers.	

2 Background

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

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

New South Wales: 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: 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: The electricity DNSP is Power and Water.

We report separately on three scheme (transmission) pipelines: Amadeus Gas Pipeline, Roma Brisbane Pipeline and Victorian Transmission System, which operate on a different reporting schedule. We plan to report on these gas transmission network service providers (TNSPs) as an addendum to this report in the second half of 2024.

2.1 Stakeholder engagement for this report

In developing this report, we:

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

Following the release of this report, we will engage with stakeholders with a view to identifying potential focus areas for further analysis.

2.2 Data used in this report

The length of the data series in this report and our datasets differ across the energy sectors and the type of data. The data series for electricity NSPs starts at 2006, whilst for gas NSPs it starts at 2011. The financial performance data for both sectors start at 2014. Data in this report is sourced from regulatory information notices (RINs), post-tax revenue models (PTRMs) and roll-forward models (RFMs), which are published on the AER website.

The National Electricity Rules (NER) and National Gas Rules (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.[6] 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 included the methodology we use to calculate the financial performance measures in Appendix C, D and E.

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.

2.3 The 2023 regulatory year is different across networks

In this report the 2023 regulatory year for NSPs is the period 1 July 2022 to 30 June 2023. The exceptions are AusNet Services (transmission) which has a regulatory year from 1 April 2022 to 31 March 2023 and Victorian gas DNSPs which are in transition from a calendar year to a financial year.

In this report the 2023 regulatory year for the Victorian gas DNSPs consisted of the period 1 January 2023 to 30 June 2023, as the Victorian government amended the commencement 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. We have annualised this six-month

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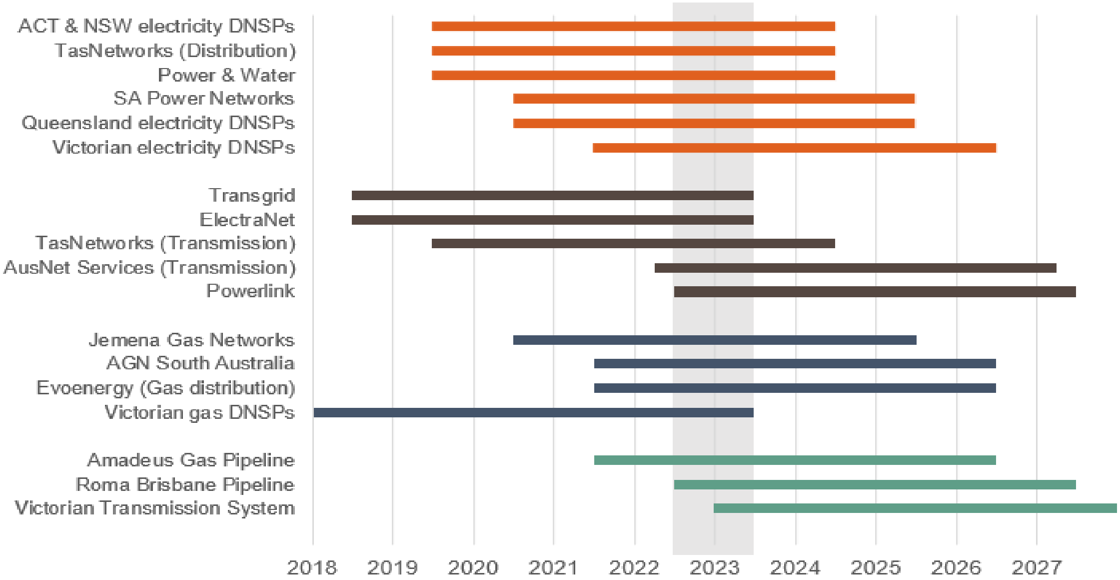
6 ACCC/AER, *Information policy*, June 2014, p 9.

period in this report, which has impacted the likely accuracy of some reporting measures. We expect these issues to be resolved when we report on a full regulatory year for Victorian gas DNSPs in next year's report.

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 NSPs regulated by the AER



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 the Australian Capital Territory (ACT), New South Wales (NSW), Tasmania and the Northern Territory (NT). This is based on these regulatory determinations being the first to have implemented substantial changes in regulatory settings (e.g., 2013 Better Regulation; 2018 Rate of Return Instrument).

2.4 Reporting on network performance

Through our network performance reports, we aim to provide accessible information that improves transparency and accountability around network performance under the regulatory regime. Comparing actual network performance against forecasts and over time helps to identify and understand the effectiveness of the regulatory framework in achieving consumer outcomes, thereby supporting informed engagement and data-driven debate. Publications that complement and may be read in conjunction with this report include:

- the 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.
- the first annual Export services network performance report was published in December 2023. 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.

3 Electricity network operational performance

This chapter focuses on the performance of electricity NSPs in the 2023 regulatory year.[7] References to NSPs in this chapter relate to electricity DNSPs and TNSPs.

3.1 Electricity network costs decrease in real terms for consumers in 2023

3.1.1 Electricity network revenue continues to decrease in real terms

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 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. These are determined as building blocks, which are described in Appendix A.

Allowed revenue in this chapter relates only 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. Revenue for other purposes, such as jurisdictional specific schemes are not analysed in this chapter.[8]

In 2023, network customers paid an average of $1,142 to NSPs. Of this, $908 was paid to DNSPs and $234 to TNSPs. This is a decrease of $48 compared to 2022 in real terms, or an increase of $14 in nominal terms. In total, NSPs recovered $12.5b from customers, 2.9% percent less in real terms than the previous year.

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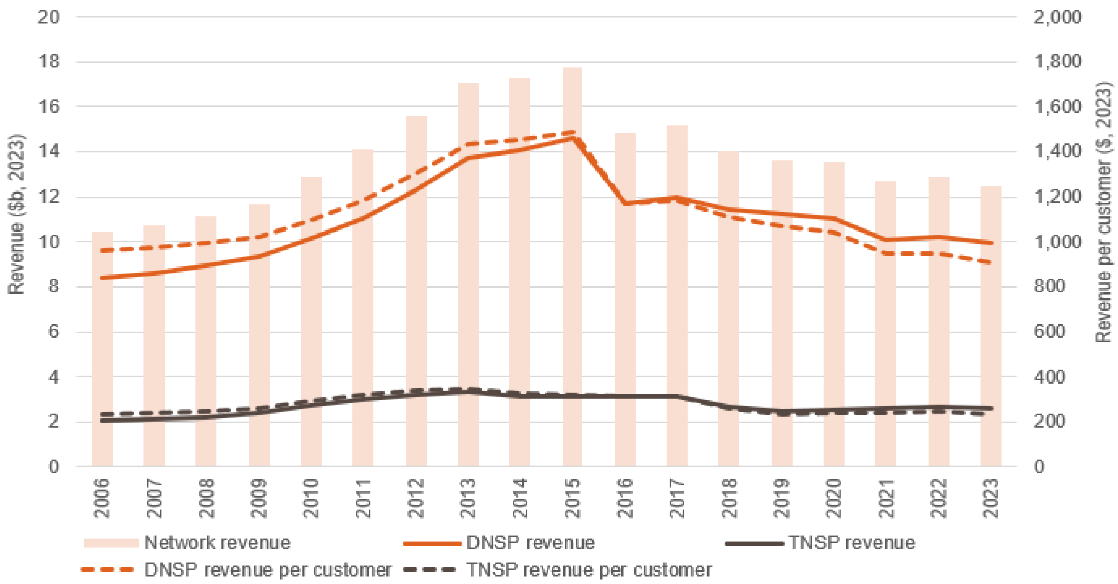
7 The 2023 regulatory year is between 1 July 2022 and 30 June 2023 for all electricity NSPs, except for the AusNet Services TNSP, which has a regulatory year between 1 April 2022 and 31 March 2023.

8 This is in reference to jurisdictional revenue schemes which are pass through revenues. In future reports we will report on the capex and opex in relation to the NSW Electricity Infrastructure Roadmap and NSW Energy Renewables Zones in our expenditure section.

Figure 3-1 Network revenue - NSPs - $ real 2023



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 2023 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.

In 2023 revenue per customer was the lowest it has been since before 2006 for both DNSPs and TNSPs. Further, overall revenue in real terms is the lowest it has been since 2009.

In the second half of the 2022 calendar year and the first half of the 2023 calendar year there was a considerable increase in inflation. Although there has been an increase in revenue in nominal terms in 2023, the increase remains below inflation.

Further, nominal network revenue per customer remains $363 below its peak in 2015,[9] which, as discussed in a previous year's report[10], was the year in which reductions in allowed returns on capital and specifically lower rates of return began to be applied in NSPs' regulatory determinations.[11]

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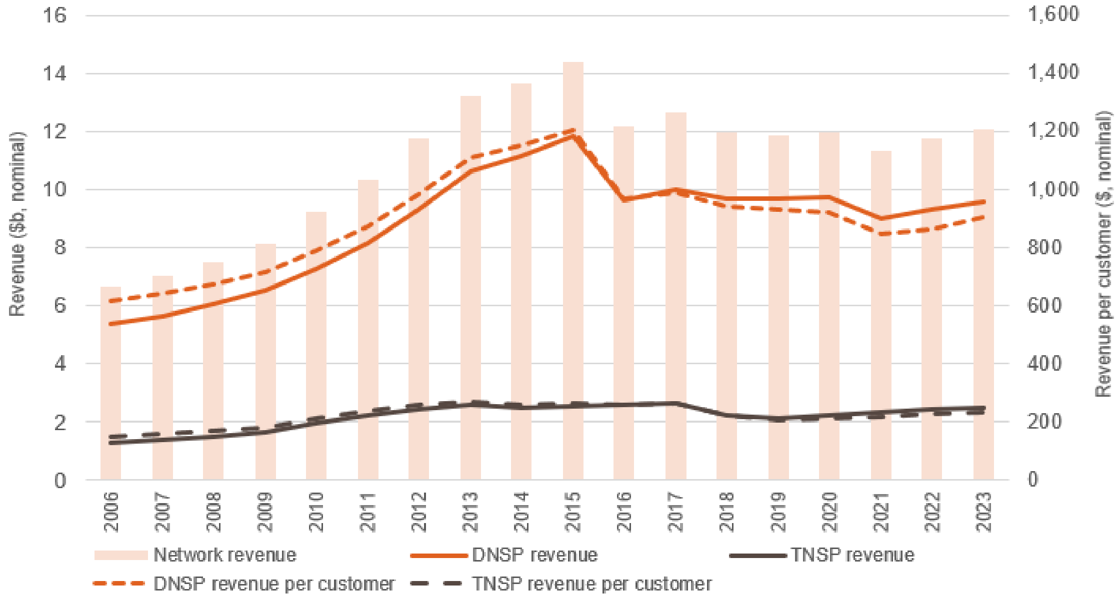
9 This involved $1,202 of DNSP revenue per customer and $169 of TNSP revenue per customer. DNSP revenue per customer peaked in 2015, whilst TNSP revenue per customer peaked in 2017. The difference is due to the timing of lower rates of return in respective TNSPs regulatory determinations.

10 AER, 2020 Electricity network performance report, September 2022, p 10.

11 Refer to section 3.1 of the 2020 Electricity network performance report for further discussion.

Figure 3-2 Network revenue - NSPs - $ nominal



Source: Provided in Figure 3-1

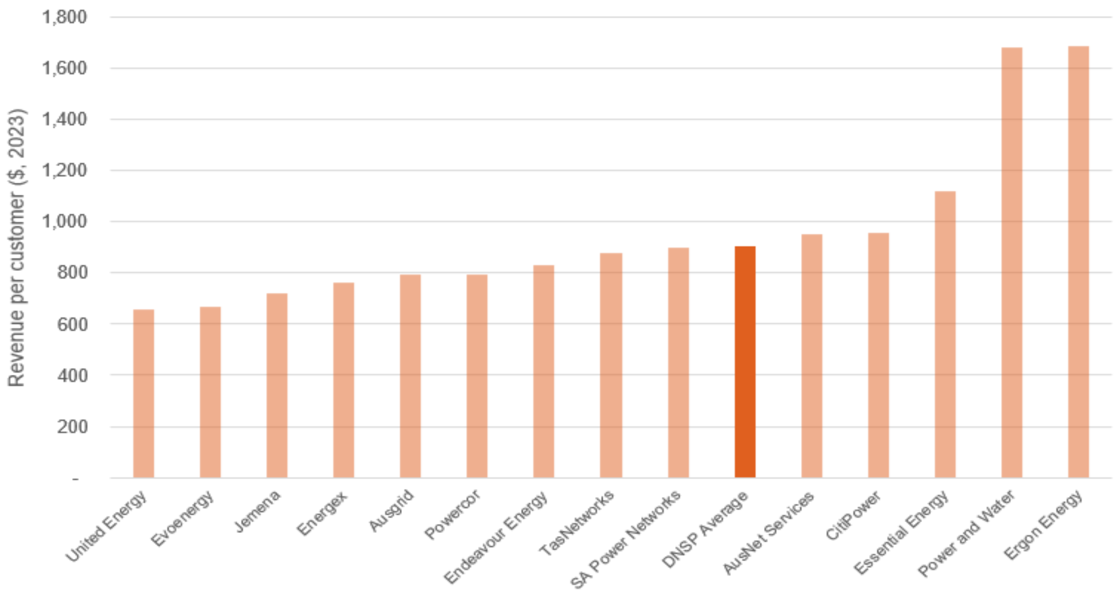
Note: Provided in Figure 3-1, except for AER calculation to convert to mid-year nominal values.

3.1.1.1 Revenue per customer decreases but varies across electricity networks

The DNSP revenue per customer is calculated using the distribution revenue of 14 DNSPs, whilst the TNSP revenue per customer uses the transmission revenues of 5 TNSPs.

The revenue per customer is highest for Ergon Energy and Power and Water, and to a lesser extent Essential Energy. This is expected as these NSPs typically have larger RABs per customer (discussed below) and larger expenditures per customer, both of which result in higher revenues for returns on capital and returns of capital building blocks.

Figure 3-3 Distribution revenue per customer - 2023 - $ real 2023



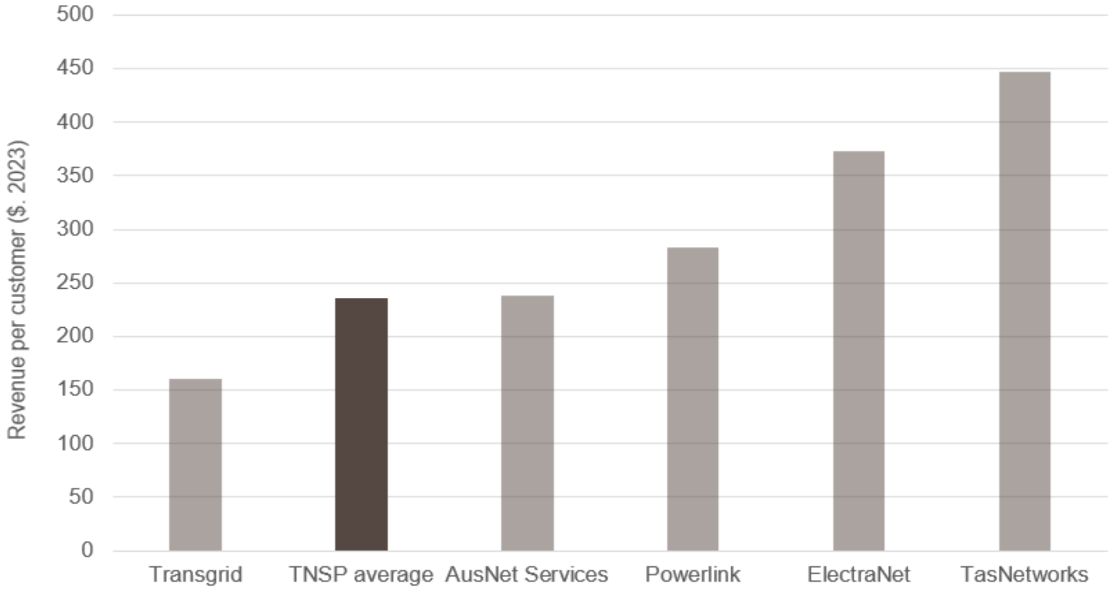
Source: Distribution revenue: Annual RIN table 8.1.1.1, 'Revenue - standard control services' for electricity DNSPs. Where annual RIN data is not available for electricity DNSPs, data is from EB RIN table 3.1.1, 'Revenue grouping by chargeable quantity.' Customer numbers data is from EB RIN table 3.4.2, 'Distribution customer numbers by customer type or class.'
Note: AER calculation to convert to $ June 2023 terms. Electricity DNSP revenue per customer calculated by dividing electricity DNSP's revenue by electricity DNSP's customer numbers.

There are 5 DNSPs with revenue per customer above average. Of these, 4 have a higher RAB, primarily due to these NSPs serving a high proportion of rural customers - Ergon Energy, Power and Water, Essential Energy and AusNet Services. As rural customers are more geographically dispersed, there is a need for more investment of network assets to distribute electricity, which is then spread over a lower customer base.

While Figure 3-3 shows revenue per customer for electricity DNSPs, revenue on Ergon Energy and Energex's networks is collected from customers across both networks. Therefore, network costs paid to Ergon Energy are lower than shown and network costs paid to Energex are higher. This is due to the Community Service Obligation, where the Queensland government provides a subsidy to keep Ergon Energy's network costs on par with Energex.

The same trend of higher revenues than average is also noted in transmission revenues per customer, with higher revenues for TNSPs with fewer customers or a higher proportion of rural customers.

Figure 3-4 Transmission revenue per customer - 2023 - $ real 2023



Source: Transmission revenue - EB RIN table 3.1.1, 'Revenue grouping by chargeable quantity'. 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 2023 terms. TNSP revenue per customer calculated by dividing TNSP's revenue by the sum of distribution customers located in the same region as the TNSP.

3.1.2 Electricity networks earned their highest incentive scheme revenues

We incentivise NSPs to improve customer outcomes by increasing their efficiency, reducing costs, and improving service performance. This is accomplished by incentive schemes (Table 3-1) which provide a monetary benefit for meeting performance targets, and conversely impose an expense for falling short of performance targets.

Incentive schemes are designed to motivate NSPs to take actions that benefit customers. The goal 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

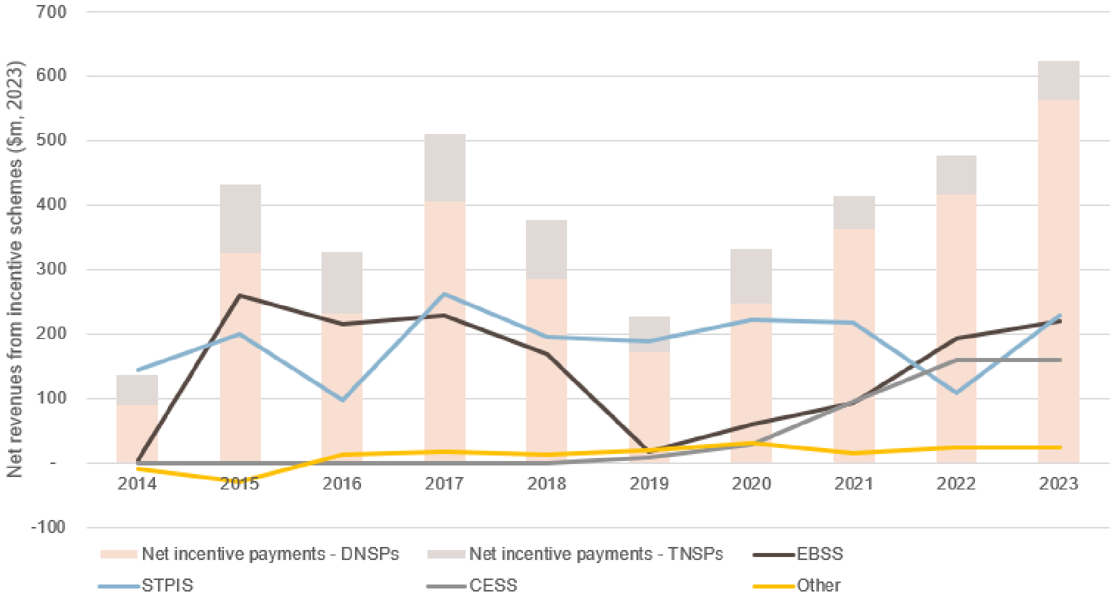
Incentive Schemes	Description
Efficiency benefit sharing scheme (EBSS)	Incentivises NSPs to reduce their operational expenditure (opex) by allowing them to keep opex savings for 6 years after they are reduced. Revealed efficiencies are then reflected in lower opex allowances in future years.
Capital 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 2023, NSPs earned $633m in incentive revenues, the highest since incentive schemes were implemented by the AER. This is largely driven by an increasing number of NSPs receiving CESS incentives in recent years while EBSS and STPIS incentives are also elevated.

The incentive scheme revenues for DNSPs in 2023 increased in real terms by $148m (36%) from the previous year, which was previously the highest amount. For TNSPs there was a slight decrease in real terms from last year, with incentive scheme revenues significantly down (44%) from their peak in 2015.

Figure 3-5 Revenue from incentive schemes - NSPs - $ real 2023



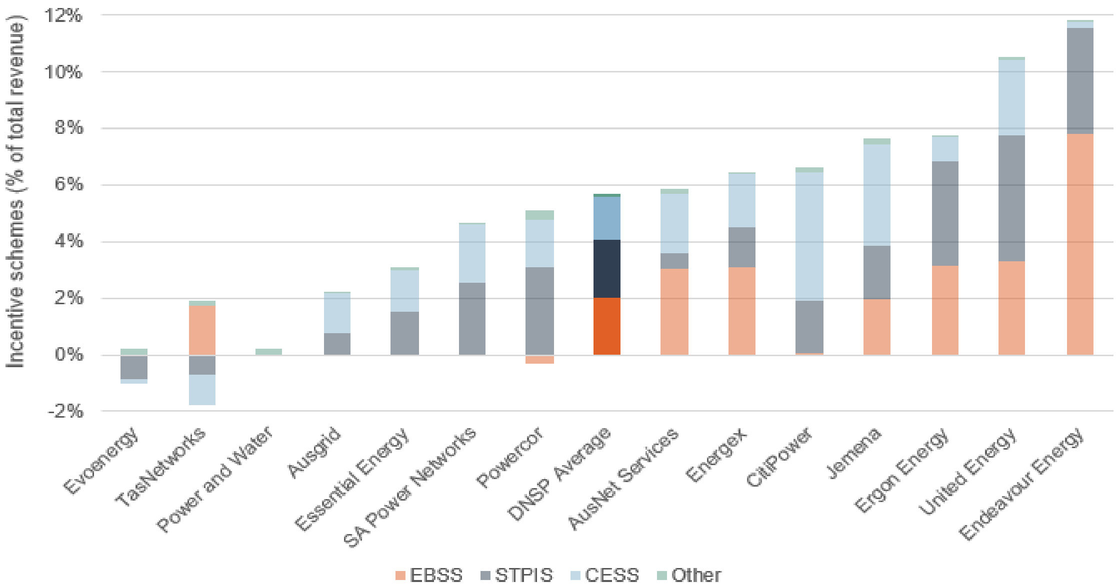
Incentive scheme revenues/payments from EB RIN table 3.1.3, 'Revenue (penalties) allowed (deducted) through incentive schemes.' Where incentive schemes revenue/payments are not available, data is from respective NSP's PTRM, 'Revenue adjustments.'
Notes: AER calculation to convert to $ June 2023 terms.

3.1.2.1 Incentive schemes as proportion of revenue differ across electricity networks

In 2023, for NSPs on average $40m (5.7%) of distribution revenue and $12m (2.3%) of transmission revenue is attributable incentive scheme revenues. These revenues do not relate to NSPs' performance during the regulatory year or the current regulatory period, but rather their performance in the previous regulatory period.

As would be expected, the revenues earned varied considerably across the DNSPs, with Endeavour Energy receiving the highest revenues from incentive schemes at 11.8% (primarily due to EBSS and STPIS) and Evoenergy receiving the lowest, with net payments of 0.8% of revenue.

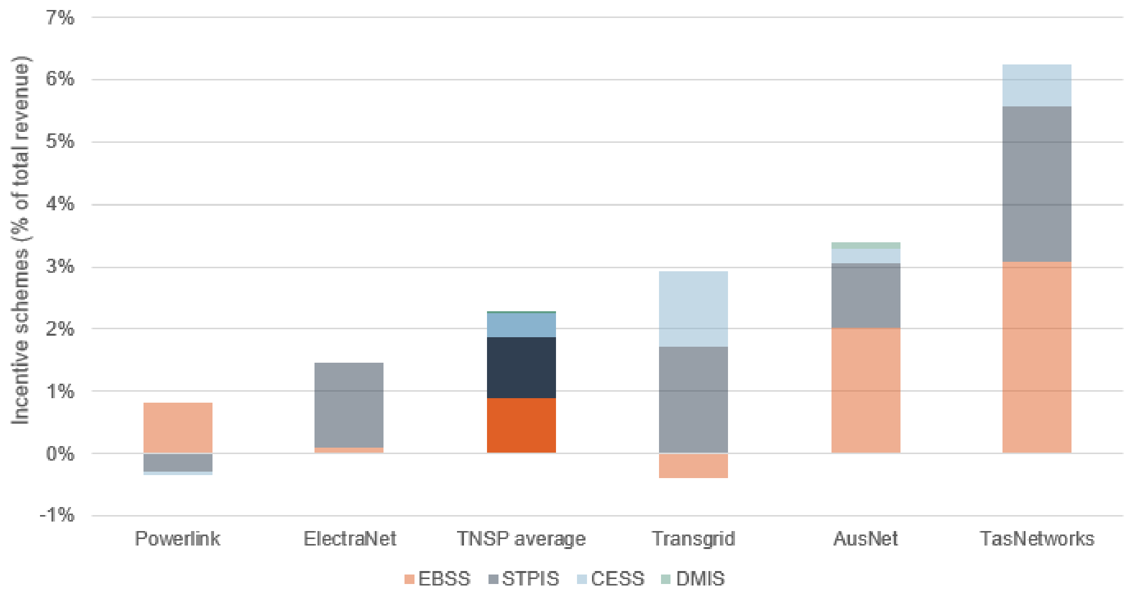
Figure 3-6 Distribution revenues from incentive schemes - 2023 - $ real 2023



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 the TNSPs however there is a lower range in the minimum and maximum revenues. This may be due to TNSPs earning lower CESS rewards, with only $10m (17% of total incentive scheme revenues) earned in 2023, which contrasts to $149m (26% of total incentive scheme revenues) being earned by DNSPs.

Figure 3-7 Transmission revenues from incentive schemes - 2023 - $ real 2023



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.'

In the upcoming regulatory years, we expect to see similar incentive scheme revenues, as more NSPs are now earning incentive scheme revenues from CESS rewards alongside their EBSS and STPIS rewards. This will enable NSPs to earn above their allowed returns and enable higher network costs to be charged to consumers in the short term, whilst providing consumers with improved long-term outcomes from passing through efficiency gains and improvements in reliability.

3.1.3 Cost pass through events are increasing electricity network costs

The NER[12] allow NSPs to recover costs associated with unforeseen events that are outside of an NSP's control. 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 can be positive (increasing allowed revenue) or negative (decreasing allowed revenue). Cost pass throughs may either directly increase the revenue allowed to be collected by an NSP or may increase revenue in future years by increasing the NSPs capex allowance, which flows through to increase the NSP's RAB.

The AER received 10 cost pass through applications in 2023, which has led to an increase in forecast revenues for NSPs in 2023, 2024 and 2025. In 2023, $61m of pass-through revenues are associated with natural disasters impacting the network assets of Ausgrid, AusNet Services, Endeavour Energy, Energex, Essential Energy and Transgrid. These natural disasters did not necessarily occur in 2023, as they related to various events including the 2019-20 Black Summer bushfires and eastern Australian floods in February and March 2022. An additional $64m of approved cost pass through revenues will be passed through for natural disasters in 2024.

Other cost pass throughs in 2023 relate to notable increases in the easement tax paid by AusNet Services (transmission), and regulatory requirement changes for Essential Energy and SA Power Networks.

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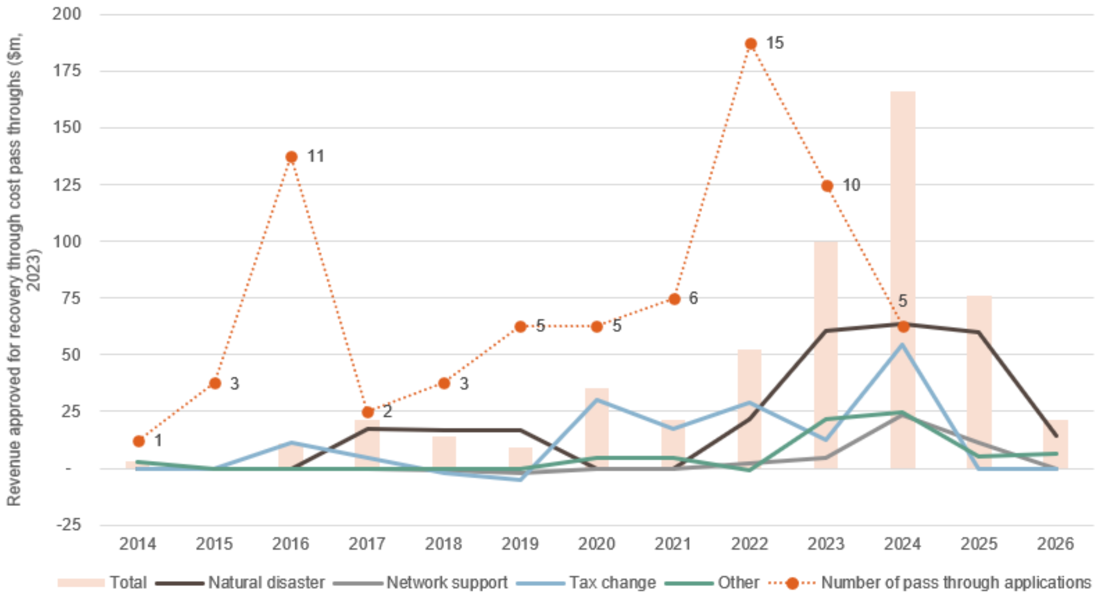
[12] Under NER cl 6.6.1 for DNSPs and NER cl 6A.7.3 for TNSPs.

Figure 3-8 Revenue from cost pass throughs - NSPs - $ real 2023



Source: AER analysis of decisions under AER, Cost pass-throughs, accessed 19 March 2024.
Note: Calculation to convert values to $ June 2023 terms.

Figure 3-8 shows the revenue approved in cost pass-through applications lodged to February 2024 and therefore after the end of the 2023 regulatory year. When interpreting Figure 3-8, readers should note that this analysis:

- Excludes the $440m and $384m of feed-in-tariff costs passed through to Queensland customers in 2016 and 2017 respectively. As these amounts were much larger than other pass-through amounts, including them would make it difficult to view changes in other revenue streams.
- While our previous report's analysis reported pass through costs when the associated events occurred, Figure 3-8 reports when NSPs will recover these costs from customers. For some pass throughs, NSPs recover costs over several years after the event, which is why Figure 3-8 includes cost pass through revenue to be recovered up to 2026.
- Excludes AER's contribution determinations of $138m to be paid by NSW DNSPs to the NSW Electricity Infrastructure Fund established under the (NSW) Electricity Infrastructure Investment Act. These are a jurisdictional scheme cost pass through, which will be passed through to NSW DNSP customers in 2024, with an additional $341m to be charged to consumers in 2025.

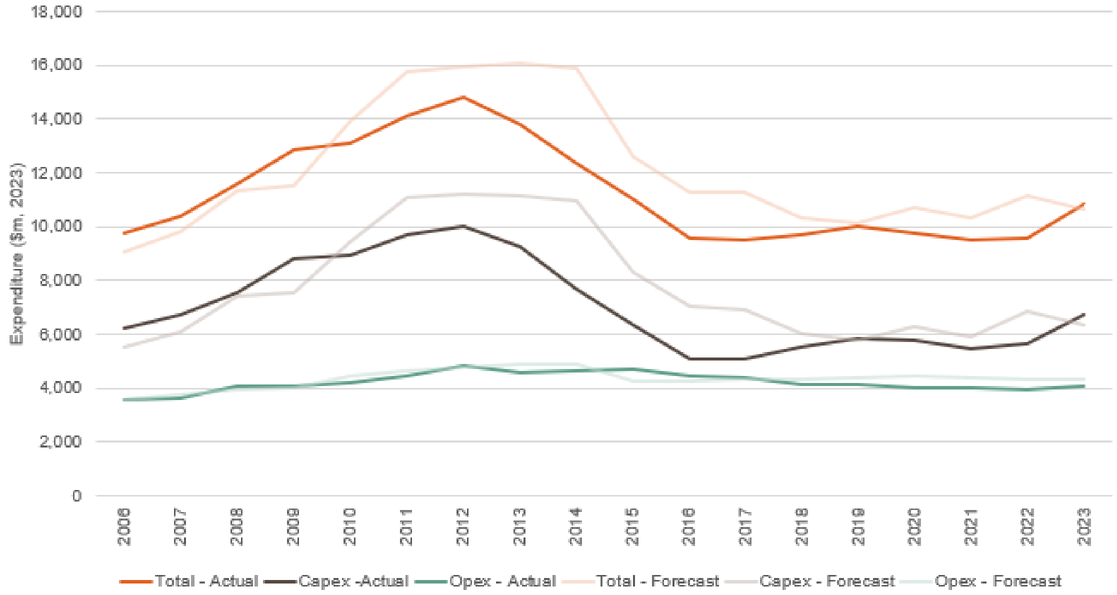
3.1.4 Increase in capex leads to highest expenditures since 2016

An NSP's total expenditure is the sum of 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.

As we provided in our first report, total expenditures have decreased following the capex investments peaking in 2012.[13]

Figure 3-9 Total Expenditure - NSPs - $ real 2023

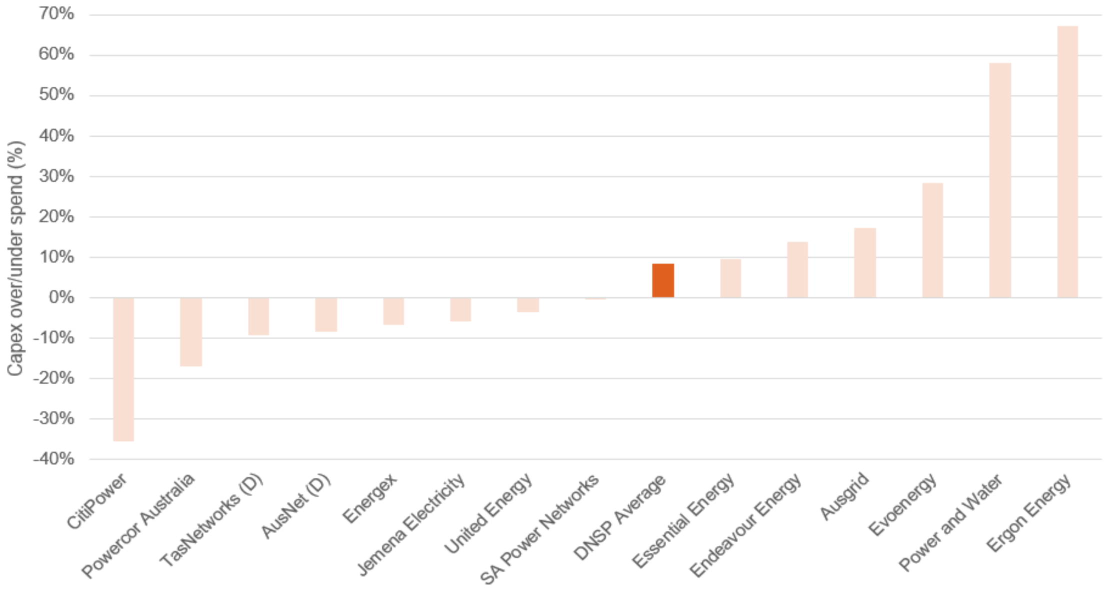


Source: Actual capex: RFM input - 'Actual capex,' 'Actual asset disposal,' 'Actual capital contributions.' Where RFM not available for TNSPs, use category analysis RIN: 2.1 Expenditure Summary, (ii) for DNSPs, use annual RINs: Table 8.2.4 'Capex by asset class,' Table 8.2.5 'Capital contributions by 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 2023 terms. Net capex is gross capex less capital contributions and disposals.

In 2023, total expenditure was the highest it has been since 2016, driven by an increase in capex, which was an aggregate overspend of the NSP's total capex allowance. This has been primarily due to the NSW, ACT and NT DNSPs and Ergon Energy, who each overspent by approximately 10% of their capex allowance in 2023 in real terms.

[13] AER, Electricity network performance report 2020, September 2020, p 19.

Figure 3-10 Capex over/under spend - DNSPs - 2023 - $ real 2023



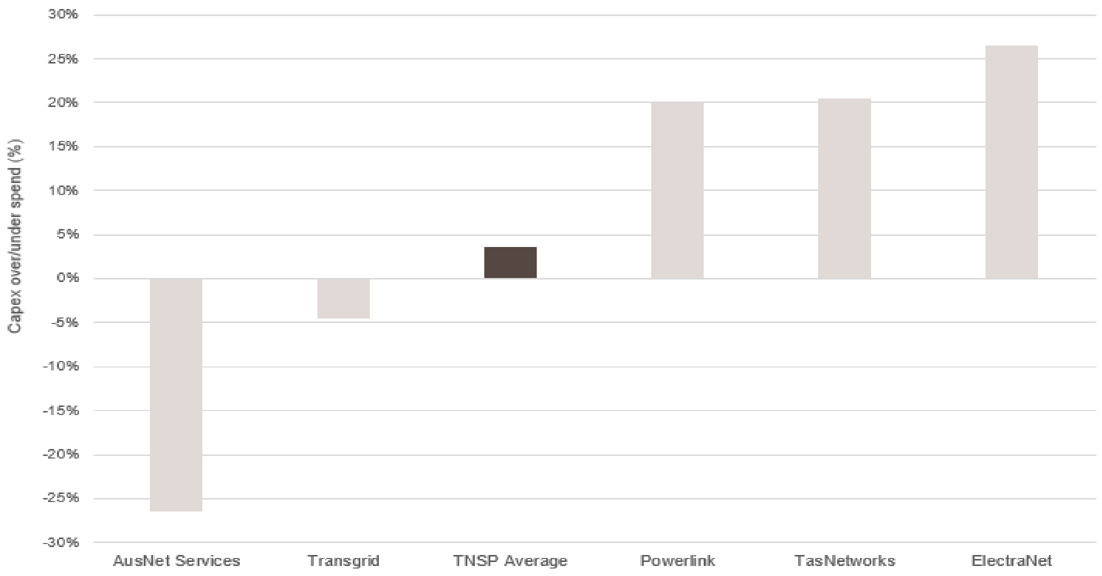
Source: Actual capex: RFM input - 'Actual capex,' 'Actual asset disposal,' 'Actual capital contributions.' Where RFM not available have used annual RINs: Table 8.2.4 'Capex by asset class,' Table 8.2.5 'Capital contributions by asset class,' Table 8.2.6 Disposals by asset class. Forecast capex: PTRM Input - 'Forecast net capex.'
Note: AER calculation to convert values into $ June 2023 terms. Net capex is gross capex less capital contributions and disposals. Capex over/under calculated by comparing actual capex against forecast capex for respective regulatory year

The capex overspends by Ergon Energy are discussed in further detail below. Power and Water's capex overspends were across their network, with a focus on ICT projects, deferred replacement projects and a revision to methods by which overheads expenditures are capitalised to enable consistency with their statutory reporting.[14]

For TNSPs in 2023, although AusNet Services and Transgrid had capex underspends, there were overspends by ElectraNet, TasNetworks and Powerlink relative to their annual capex allowance.

14 Power and Water, Annual RIN Response 2022-23 - table 8.2.2 Capex by purpose - material difference explanation, October 2023.

Figure 3-11 Capex over/under spend - TNSPs - 2023 - $ real 2023



Source: Actual capex: RFM input - 'Actual capex,' 'Actual asset disposal,' 'Actual capital contributions.' Where RFM not available use CA: 2.1 Expenditure Summary. Forecast capex: PTRM Input - 'Forecast net capex.' Note: AER calculation to convert values into $ June 2023 terms. Net capex is gross capex less capital contributions and disposals. Capex over/under calculated by comparing actual capex against forecast capex for respective regulatory year

The overspends by ElectraNet, TasNetworks and Powerlink resulted in a collective overspend in real terms of 3.6% or approximately $70m for TNSPs. This low collective underspend for TNSPs, is due to Transgrid's capex allowance for 2023 being $1,059m, which was over half (56%) of the entire TNSP allowance. The higher capex allowance for Transgrid was a result of the project EnergyConnect[15] decision[16], which added $1,866m to their forecast capex from their 2018-23 regulatory determination.

EnergyConnect was due to be completed by the end of the 2023 regulatory year, however as noted in last year's report, its capex was reprofiled. Our final decision for Transgrid's 2023-28 regulatory period involves $1.1b in capex allowance in relation to completing EnergyConnect, with this allowance primarily in 2024 and 2025.[17]

The overspend for ElectraNet has been driven by the Eyre Peninsula Transmission Supply project[18] and their share of the capital investment for Project EnergyConnect.[19] The overspend on EnergyConnect occurred due to the capital investment being delayed from

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15 Project EnergyConnect is a new interconnector between South Australia at Robertstown and NSW at Wagga Wagga, together with a spur line linking to Victoria at Red Cliffs. This interconnector is being constructed by TransGrid and ElectraNet, with TransGrid having most of the capex investment.

16 AER, Final Decision - TransGrid contingent project - EnergyConnect, May 2021, p 1.

17 AER, Attachment 5 - Capital expenditure - Final decision - Transgrid transmission determination 2023-28, April 2023, p 4.

18 Eyre Peninsula Link is a new 270-kilometre double-circuit 132 kV high-voltage transmission line from Cultana to Port Lincoln, via Yadnarie. This involved the construction of 500 new transmission towers and upgrades to five ElectraNet substations.

19 ElectraNet, ElectraNet - Capex model 2024-28 - tab 'incurred nominal, accessed 26 March 2024.

2022, where there was an underspend.[20] As discussed below, this has resulted in ElectraNet having an overall capex spend for the 2018-23 regulatory period which is closely approximate to their capex allowance.

3.1.4.1 Timing of capex continues to differ across the regulatory period

Our first report looked at the timing of capex and concluded that NSPs tend to:[21]

- underspend by a greater extent early in regulatory periods
- spend closer to, or above capex forecasts later in regulatory periods

In our analysis we noted that there are different factors that can determine patterns of capex, and that one of the issues may be that capex incentives, financial or otherwise, vary through the course of the regulatory period.

Efficiency in a NSP's capex spend is rewarded through the CESS incentive scheme, where capex lower than its annual forecast enables NSPs to keep up to 30% of the capex savings. The scheme calculates the efficiency gains and losses in net present value terms, for each regulatory year and the entire regulatory period. This balances capex spends throughout the regulatory period, with any efficiency gains from underspends negated by efficiency losses from overspends.

In their current regulatory period, 2023 was year 4 for the NSW, Tasmanian, ACT and NT DNSPs. Collectively there has been a cumulative overspend in real terms of 14% ($238m) which contrasts with the previous three years of underspends, resulting in an overall underspend for the regulatory periods in real terms of 11% ($826m). This underspend is also evident for the Victorian DNSPs, where there were underspends in 2023 and the previous year.

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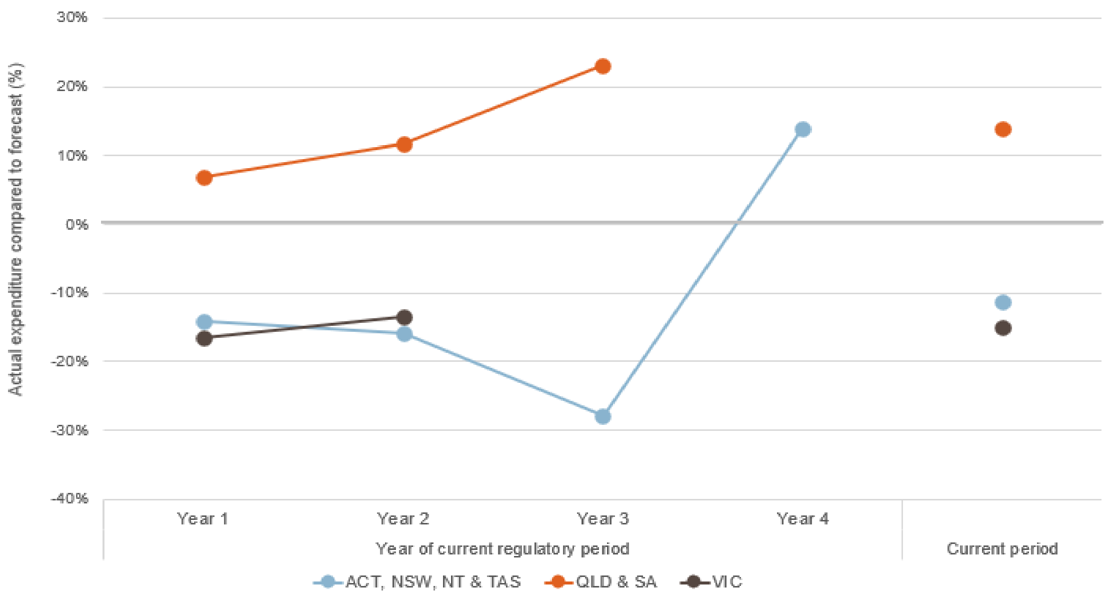
20 AER, Electricity network performance report 2023, July 2023, p 16.

21 AER, Electricity network performance report 2023, July 2023, p 16.

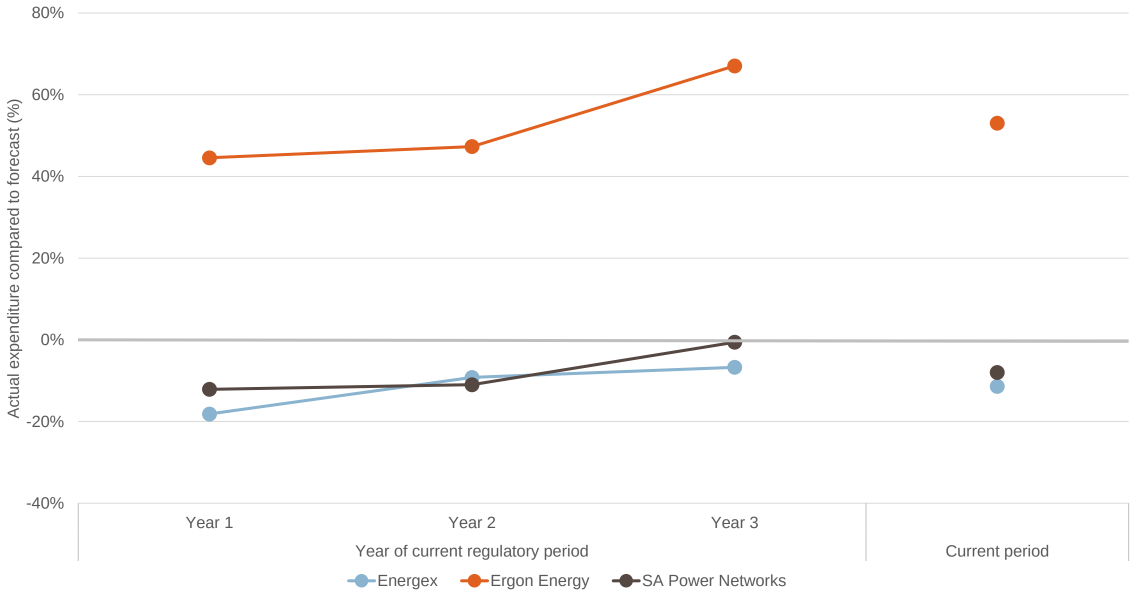
Figure 3-12 Capex over/under spend - DNSPs - current regulatory period - $ real 2023



Source: Actual capex: RFM input - 'Actual capex,' 'Actual asset disposal,' 'Actual capital contributions.' Where RFM not available have used 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. Forecast capex: PTRM Input - 'Forecast net capex.'
Note: AER calculation to convert values into $ June 2023 terms. Net capex is gross capex less capital contributions and disposals. Capex over/under calculated by comparing actual capex against forecast capex for respective regulatory year and cumulative actual and forecast capex for regulatory period.

The underspends for NSW, Tasmanian, Victorian, ACT and NT DNSPs contrasts with the overspends for the Queensland and South Australian DNSPs throughout their current regulatory period. When disaggregated into the individual DNSPs in Queensland and South Australia, it highlights that the overspend in aggregate has been primarily due to Ergon Energy.

Figure 3-13 Capex over/under spend - Energex, Ergon Energy and SA Power Networks - current regulatory period - $ real 2023



Source: Actual capex: RFM input - 'Actual capex,' 'Actual asset disposal,' 'Actual capital contributions.' Where RFM not available have used 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. Forecast capex: PTRM Input - 'Forecast net capex.'
Note: AER calculation to convert values into $ June 2023 terms. Net capex is gross capex less capital contributions and disposals. Capex over/under calculated by comparing actual capex against forecast capex for respective regulatory year and cumulative actual and forecast capex for regulatory period.

3.1.4.2 Ergon Energy overspends for fourth consecutive year

Ergon Energy has now materially overspent for four consecutive years (since 2020). This overspend was addressed by Ergon Energy in their regulatory proposal for their upcoming 2025-30 regulatory determination,[22] with an expected overspend for the 2020-25 regulatory period of $1,728m in network capex and $282m in non-network capex. [23] The details of this overspend is summarised in Table 3-2.

22 Ergon Energy, Ergon Energy network regulatory proposal - 2025-30, January 2024, p 33.

23 Ergon Energy, Ergon Energy network regulatory proposal - 2025-30, January 2024, pp 33-35.

Table 3-2 Ergon Energy overspend for 2020-25 regulatory period

Capex driver	Explanation
Replacement expenditure	Expected overspend of $1,274m due to: • pole failures and changes to pole serviceability calculation leading to identification of a larger than forecast number of defective poles requiring replacement • the consequential replacement of transformers, cross-arms, overhead switches, and service cables associated with the pole replacements • increase in Ergon Energy's reconductoring program to address the safety and reliability risk from unassisted conductor failures
Connections	Expected overspend of $71m due to an impact of new connections from COVID-19 migration to regional Queensland and a predicted COVID-19 slowdown for construction not eventuating.
Safety- related augmentation expenditure	Expected overspend of $200m due to a safety requirement under Queensland's *Electrical Safety Act* 2002 to maintain minimum distances between overhead conductors and the ground or adjacent structures.
Other augmentation expenditure	Small overspend to complete a project at Jubilee Pocket, which is part of the network upgrade in the Whitsundays region.
Non-network	Expected overspend of $282m due to: • significant investment into non-network ICT systems, including replacing their Enterprise Resource Planning and Enterprise Asset Management systems and maturing their cyber security capabilities • the timing of investment in non-network property projects due to project phasing and contractor availability • increased property, fleet and equipment costs due to general industry and market conditions, which has increased unit costs across projects and equipment

Source: Ergon Energy Network Regulatory Proposal - 2025-30

Due to the significant size of their overspend, the AER will consider whether any other capex overspend from the last two years of their previous regulatory period and the first three years of their current regulatory period[24] are included in the opening balance of the RAB for the 2025-30 regulatory period. These considerations will be made in accordance with the ex post measures for efficient capex from our Capital expenditure incentive guideline for electricity network service providers, which enables overspent capex that does not reflect the capex criteria to be excluded from the RAB.

24 The previous regulatory period for Ergon Energy is the 2015-20 regulatory period and the current regulatory period is the 2020-25 regulatory period.

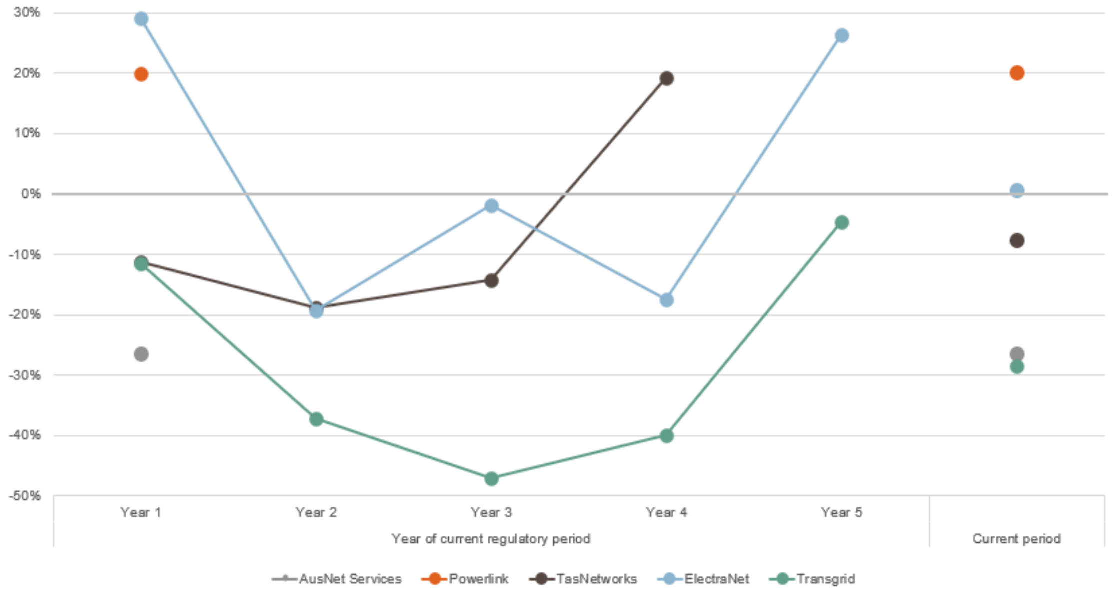
A draft determination for Ergon Energy's opening RAB for the 2025-30 regulatory period will be made by 30 September 2024. We will report on this decision in next year's report.

3.1.4.3 Increase in electricity transmission network capex follows underspends in previous years

In their current regulatory period, 2023 was year 4 for TasNetworks and year 5 for Transgrid and ElectraNet, whilst it was first year for AusNet Services and Powerlink. The capex spends across the TNSPs regulatory periods differ, with:

- TasNetworks remaining below their capex allowance despite an overspend in 2023
- ElectraNet's overspending its allowance in 2023, resulting in an overall capex spend for the 2018-23 regulatory period which is approximate to their capex allowance
- Transgrid significantly underspending their capex allowance in their 2018-23 regulatory period.

Figure 3-14 Capex over/under spend - TNSPs - current regulatory period - $ real 2023



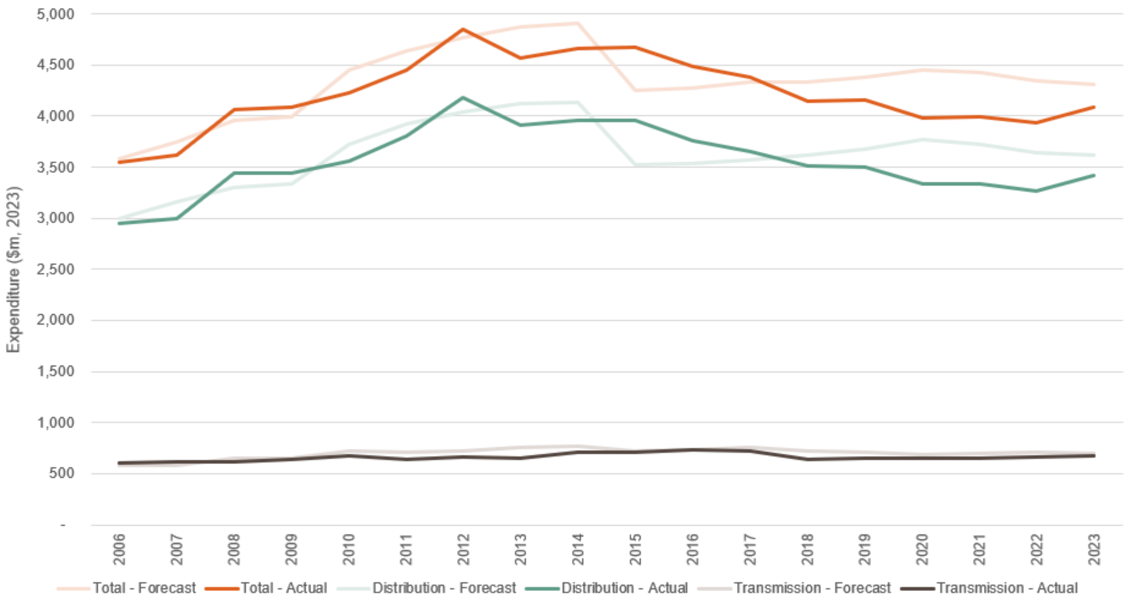
Source: Actual capex: RFM input - 'Actual capex,' 'Actual asset disposal,' 'Actual capital contributions.' Where RFM not available have used regulatory accounts: Forecast capex: PTRM Input - 'Forecast net capex.'
Note: AER calculation to convert values into $ June 2023 terms. Net capex is gross capex less capital contributions and disposals. Capex over/under calculated by comparing actual capex against forecast capex for respective regulatory year and cumulative actual and forecast capex for regulatory period.

As discussed above, the underspend by Transgrid was due to capex from EnergyConnect being reprofiled, with significant capex allowances now occurring in 2024 and 2025. For ElectraNet and TasNetworks the overspend for 2023 has resulted in the capex for the regulatory period being closer to their allowance.

3.1.4.4 Electricity networks continue to underspend opex allowance, delivering benefits for networks and consumers

In 2023, NSPs collectively underspent on their opex allowance of $4.3b, by $222m (-5.2%) resulting in total opex spending of $4.1b.

Figure 3-15 Opex - NSPs - $ real 2023



Source: Actual opex: EB RIN - Table 3.2.2 'Opex'. Forecast opex: PTRM Input - 'Forecast operating and maintenance expenditure.'
Note: AER calculation to convert values into $ June 2023 terms. Total is the cumulative total of actual and forecast distribution and transmission opex.

There has been a cumulative underspend by NSPs of their opex allowance for 6 consecutive regulatory years, with both DNSPs and TNSPs underspending their allowance. Opex efficiency by NSPs will contribute to outperformance against their allowed returns, though it will benefit consumers through lower opex expenditure forecasts in future regulatory determinations. This is a key feature of our incentive based regulatory framework and enhances the propensity for continual improvement by NSPs in delivering better outcomes for consumers.

3.1.5 RAB values increase slightly with valuations expected to rise significantly in future years

The RAB represents the total economic value of network assets that NSPs use to provide regulated network services.

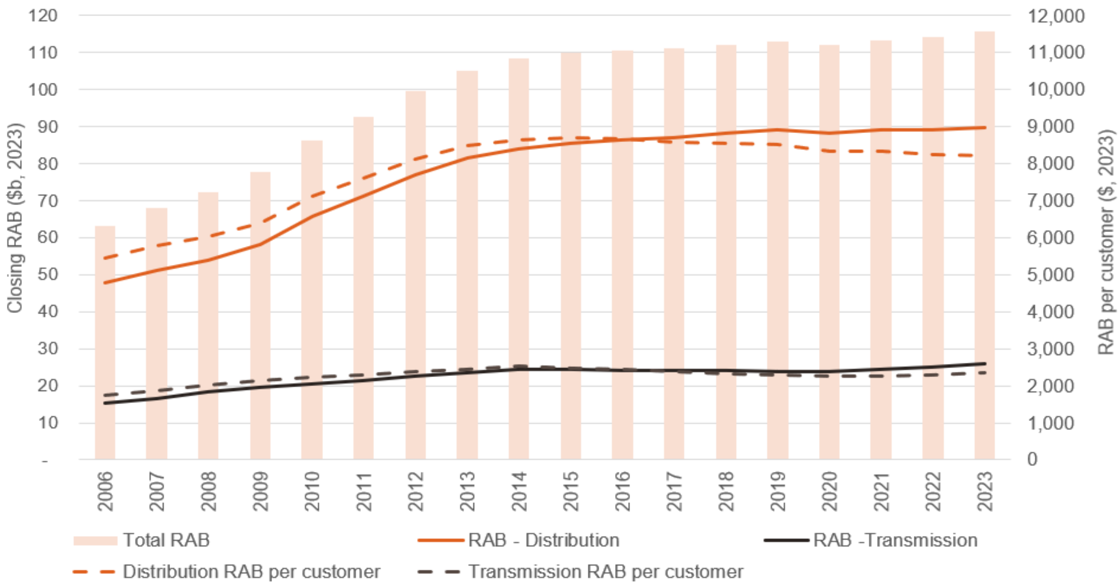
RAB values substantially affect an NSPs' revenue requirements, and the total costs customers ultimately pay. In 2023, approximately 60% or $7.8b of the total forecast revenue for NSPs relates to the return on capital and return of capital building blocks (as discussed in Appendix A).

As the RAB is constantly changing, as new assets replace aging and depreciated assets, the average economic life of network assets varies across the NSPs. This results in some NSPs requiring significant a capital allowance for growth or replacement of their network assets, whilst others require less investment. This results in the annual movements in the real value of a RAB differing amongst the NSPs, with some increasing from capital investment exceeding depreciation, whilst others decrease from higher depreciation.

In 2023, there was a 1.4% increase in NSPs RAB in real terms, with a combined value of $115.7b. Disaggregated, there was a:

- 0.8% increase in real terms in the RABs of DNSPs for a combined value of $89.9b
- 3.5% increase in real terms in the RABs of TNSPs for a combined value of $25.8b.

Figure 3-16 RAB - NSPs - $ real 2023



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 2023 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.

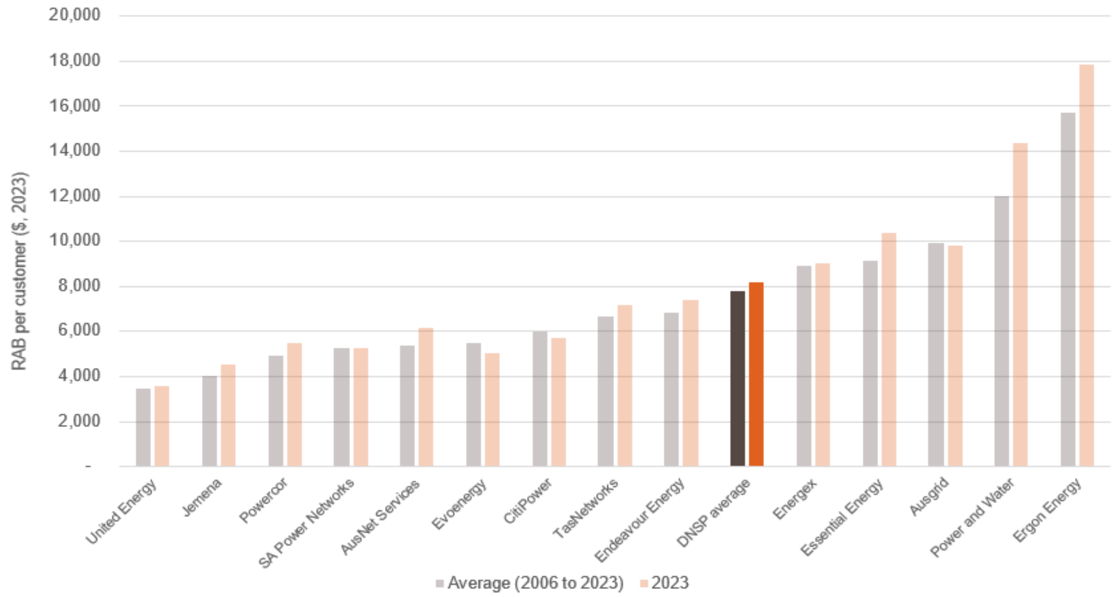
The RAB per customer in 2023 was $8,206 for DNSPs (a decrease of 0.4% in real terms) and $2,359 for TNSPs (an increase of 2.2% in real terms), resulting in an overall increase of $16 in real terms in 2023 (an increase of 0.1%).

3.1.5.1 Higher RABs per customer driven by geographical size of electricity networks

As detailed above, the revenues per customer are dependent on the RABs per customer, which differ across the NSPs and has changed over time.

The valuation of 2023 RABs is based on historical capex. We expect RABs to change over time, as an NSP's needed capex will depend on the network's age and technology, load characteristics, the levels of new connections and reliability and safety requirements.

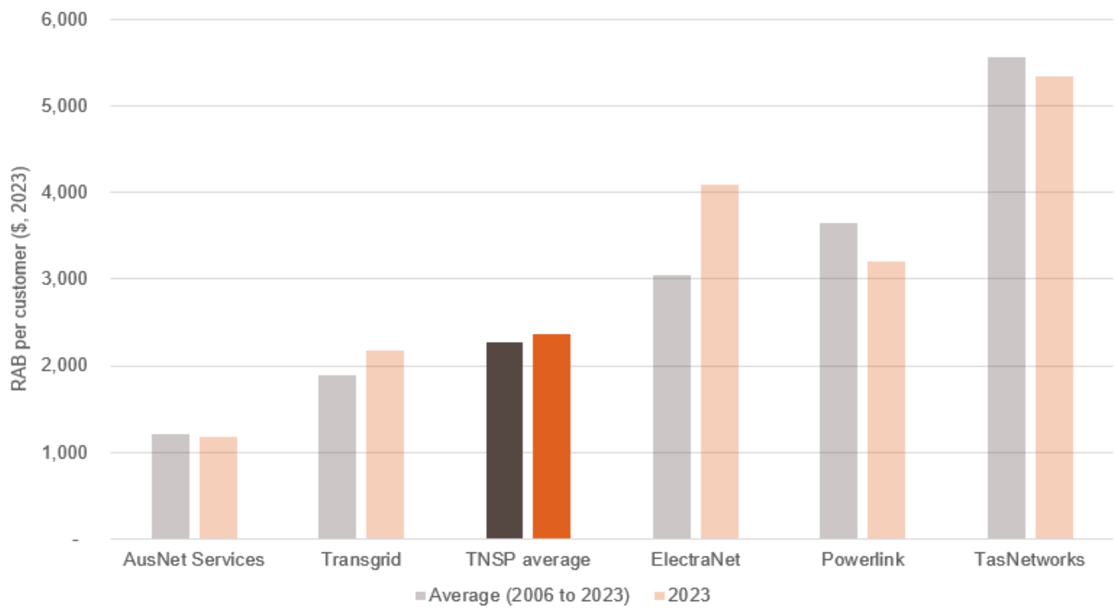
Figure 3-17 RAB per customer - DNSPs - $ real 2023



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 2023 terms. DNSP RAB per customer calculated by dividing DNSP's RAB by DNSP's customer numbers.

The changes in RAB per customer differ across the DNSPs over time. The increased recent growth in the RAB for Power and Water and Ergon Energy without a corresponding growth in customer numbers, has resulted in a noticeably higher RAB per customer than their historical average. This contrasts to Evoenergy, CitiPower and Ausgrid, where lower recent capex has resulted in lower RAB per customer in 2023 than their historical average.

Figure 3-18 RAB per customer - TNSPs - $ real 2023



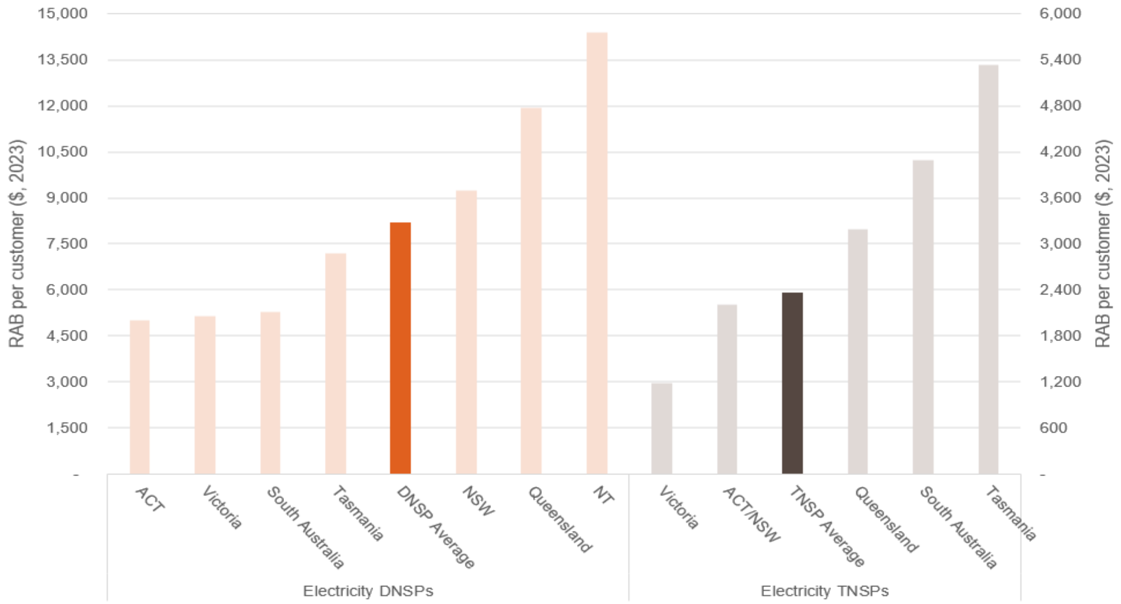
Source: Closing RAB: RFM, 'RAB roll-forward'. Customer numbers data is from EB RIN table 3.4.2, 'Distribution customer numbers by customer type or class.'
Note: AER calculation to convert to $ June 2023 terms. DNSP RAB per customer calculated by dividing DNSP's RAB by DNSP's customer numbers.

The RAB per customer also differ amongst TNSPs. For example, Powerlink's lower capex has resulted in lower RABs per customer than their historical average, which differs from ElectraNet, who have effectively doubled their RAB and RAB per customer since 2006.

3.1.5.2 RAB per customer differ across jurisdictions

The RAB per customers in Figure 3-19, indicates that both Queensland DNSPs and two of the three NSW DNSPs are higher than the DNSP average RAB per customer, with Endeavour Energy only slightly lower than the DNSP average. This suggests that there may be jurisdictional factors which have driven different RAB values for DNSPs.

Figure 3-19 RAB per customer - NSPs - 2023 - $ real 2023



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 2023 terms. DNSP RAB per customer calculated by dividing total of the jurisdictions' electricity DNSPs RAB by jurisdictions' total 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 higher RAB values for DNSPs in NSW and Queensland are attributable to the material RAB growth driven by changes in jurisdictional reliability standards and forecast demand growth, which led to considerable capex in these jurisdictions from 2009 to 2014.[25] These investments were primarily in replacement and augmentation expenditure, with augmentation expenditure immediately reducing following its peak in 2012.[26]

Although these actual expenditures from 2009 to 2014 were predominately below the NSW and Queensland DNSPs' approved capex forecasts, they were later criticised as being an overinvestment or a 'gold-plating' of the NSW and Queensland electricity distribution networks. This was due to NSPs having a potential incentive to overinvest in their networks

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25 Refer to Figure 3-9.

26 AER. Electricity network performance report - 2020, September 2020, p 20.

to achieve a higher return on capital building block. In our regulatory determinations we aim to prevent any overinvestment in three ways:

- setting capex allowances for NSPs which reflect prudent and efficient costs and are a realistic expectation of future demand and cost inputs
- excluding overspent capex which doesn't reflect the capex criteria from being added to the RAB
- setting the rates of return at an appropriate level so that NSPs can attract sufficient funds to invest but are not incentivised to overinvest into network assets

The assets built during 2009 to 2014 will be recovered by these DNSPs over the asset's economic life. Based on our recent final determination for Ausgrid's 2024-29 regulatory period, these network assets typically have a standard asset life between 45 and 70 years.[27] Due to this, it is expected that NSW and Queensland NSPs will have proportionately higher RABs per customer for a significant period.

3.1.5.3 Impact of ISP, NSW REZ, and contingent projects on electricity transmission network RAB values

During 2023, there was significant capex investment by Transgrid and ElectraNet in relation to Project EnergyConnect that is included in the ISP. The ISP is the whole-of-system plan that provides a roadmap for the efficient development of the National Electricity Market (NEM) over at least the next 20 years. In May 2021 for Project EnergyConnect, we approved $2,162m[28] of capex for Transgrid and $544m of capex for ElectraNet.

There are other ISP projects that we have approved the capex, including some expenditure in 2023. We have approved capex[29] in relation to Transgrid's HumeLink project, with approval of $413m for stage 1 (part 1), $246m[30] for stage 1 (part 2) and $3,965m for stage 2.[31] Stage 1 of HumeLink relates to pre-construction activities that can be undertaken, whilst keeping the option to either continue or discontinue the project as new information becomes available. The second stage (stage 2) relates to the completion of a new 500kV transmission that links the Greater Sydney load centre with the Snowy Mountains Hydroelectric Scheme and Project EnergyConnect in southwest NSW.[32]

Stage 1 (part 1) was expected to be completed by July 2024, with a portion of the capex occurring in 2023.[33] Stage 1 (part 2) will predominately occur in 2024 and 2025.[34]

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27 AER, Attachment 4 - Regulatory determination - Final decision - Ausgrid distribution determination 2024-29, September 2023, p 14.

28 The AER approved $1818m in 2017-18 terms. This has been converted into real June 2023 terms.

29 Refer to Transgrid - Humelink early works contingent project - stage 1 part 1 and Transgrid - Humelink early works contingent project - stage 1 part 2 for more detail.

30 The AER approved $383m for stage (1) part (1) and $228 for stage 1 (part 2) in 2022-23 terms. This has been converted into real June 2023 terms.

31 AER, AER approves reduced costs for HumeLink Stage 2, August 2024.

32 AER, AER determination - HumeLink early works - contingent project, August 2022, piii.

33 AER, AER determination - HumeLink early works - contingent project, August 2022, p 10.

34 AER, Determination - HumeLink stage 1 (part 2), August 2023, p 7.

In addition, in December 2023 we made our final decision for the non-contestable component of the Waratah Super Battery project in our role as the regulator under the NSW Electricity Infrastructure Roadmap and NSW Renewable Energy Zones (REZ). This decision approved $251m of capex[35] across 2023 to 2026, with the majority to be incurred in 2024 and 2025.[36]

The capex spent by Transgrid and ElectraNet in relation to these projects and other contingent projects has increased their RABs in 2023 and the capex approved will significantly increase their RABs in real terms in future years. In AEMO's 2024 Integrated System Plan for the National Electricity Market, in their optimal development path there are a range of ISP projects[37] which have different actionable frameworks.[38] 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 ISP projects, which may include the need for the TNSPs to undertake preparatory activities

In August 2020 we made our final guidelines to make the ISP actionable.[39] 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 tests (RIT-T).[40] The AER will then use the RIT-T application guidelines to assess the TNSP's cost benefit analysis of the best way to meet the need for the respective ISP project.

In future years we will focus on the forecast and actual capex relating to these ISPs, NSW REZ and Contingent projects and how they are impacting TNSP's RABs and revenues for consumers.

3.1.5.4 Distribution energy networks will need to modernise in the energy transition

AEMO's 2024 Integrated System Plan also envisions modernised distribution networks that delivers electricity transmitted by transmission networks to homes and businesses and takes back any surplus from consumers' own assets.[41] This is a change from the traditional view of distribution network infrastructure, being assets to solely distribute energy received from transmission networks to homes and businesses.

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35 In our final decision we also approved $25m of opex to be incurred across 2023 to 2029.

36 AER, Final Decision - Transgrid 2024-29 - non-contestable components of the Waratah Super Battery, December 2023, p 23.

37 AEMO, 2024 Integrated System Plan for the National Electricity Market, December 2023, p 12.

38 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).

39 AER, Final decision - Guidelines to make the Integrated System Plan actionable, August 2020.

40 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).

41 AEMO, AEMO's 2024 Integrated System Plan, June 2024, p 55.

The transition to a modernised distribution networks is already underway, with our 2023 Export Services report highlighting that 8% of all energy delivered in 2023 was sourced from export customers, an increase from 7% in 2022 and 5% in 2021.[42]

This energy delivered will increase in the future, as distribution networks will need to take advantage of the ISP's optimal development path which forecasts 127 GW of utility-scale renewables, 86 GW of rooftop solar and other distributed solar and 75 GW of firming technology being potentially available to consumers.

The method to which CER are incorporated into the electricity markets is still to be determined. This involves who has the roles and responsibilities in operating the distribution market and the distribution system.

This could involve AEMO, potential new distribution market and system operators, the DNSPs individually, or an alternative model which may be a hybrid of differing parties.[43] A change to these models will need the creation of a new framework, one which will require more interaction and coordination between DNSPs, AEMO and wholesale, retail, and other market participants.

The extent of infrastructure changes required to modernise the distribution networks will also be significant. Currently, the benefits of CER largely rest with those who have the means to own export assets, who are predominately older and wealthier households.[44] This locks outs renters, low-income households and vulnerable customers from the potential financial benefits received from CER, an issue which will expand as this energy is touted to be used more in homes and business.

This highlights the need for equity and the consideration of fairness for all consumers in decisions on how we modernise these networks, including how a new market operates, who pays for the infrastructure investments and how it is recovered from consumers.

Our Strategic Plan for 2020-2025[45] highlights the need to incentivise distribution networks to become platforms for energy services. To achieve this, we need to work with stakeholders to determine the best method to incentivise distribution networks and to create an energy market which is putting consumers front and centre.

3.2 Electricity networks continue to improve service outcomes

3.2.1 Residential energy delivered remains consistent with last year

The energy delivered differs across the electricity DNSPs, based on the composition and size of their customer base. Overall, there has been a slight increase in 2023, with 144.8 thousand GWh of energy delivered, with this increase being driven by higher energy delivered by non-residential customers.

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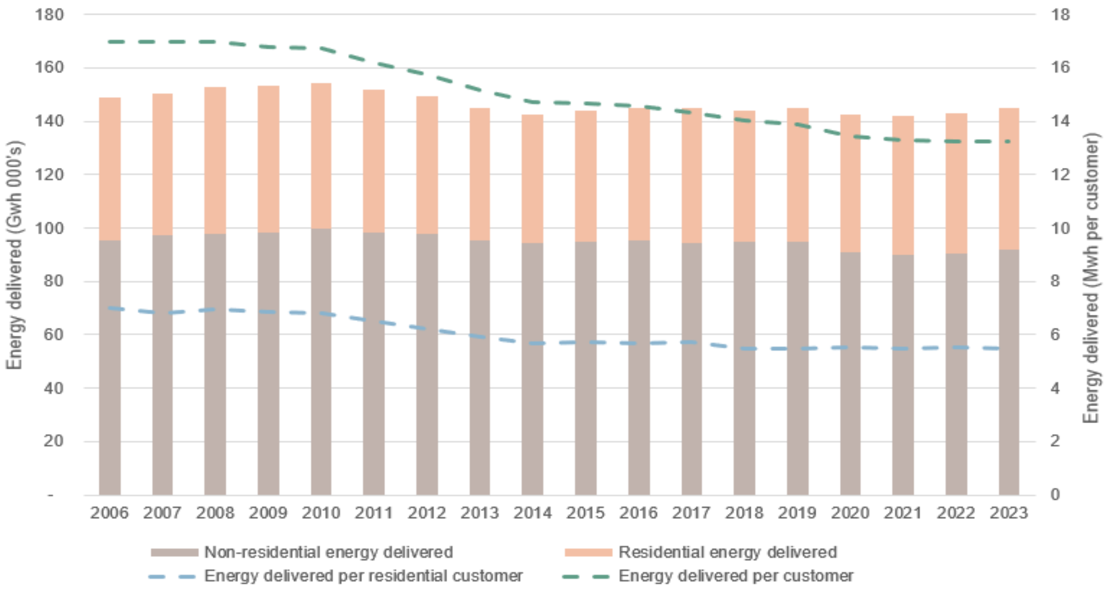
42 AER, 2023 Export Services report, December 2023, p 5.

43 ENA, Open Energy Network Project – ENA Position Paper, pp 26-31, May 2020.

44 ABS, Case study – Slow growth in solar power in Australian homes, September 2017.

45 AER, Strategic Plan for 2020-2025, December 2020.

Figure 3-20 Energy delivered - electricity DNSPs



Source: Energy 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: Energy delivered per customer calculated by dividing total of energy delivered by total customer numbers. Energy delivered per residential customers calculated by dividing residential energy delivered by residential customer numbers.

The energy delivered per customer in 2023 was consistent with last year, however, there has been a gradual decrease across our dataset. This contrasts to energy delivered per residential customer, which has been largely consistent since 2018, at approximately 5.5 MWh per residential customer.

The consistency in energy delivered per customer is due to increase in consumption from customer numbers and consumption from the electrification of household appliances being offset by rooftop solar replacing electricity previously sourced from the grid and housing and appliances being more efficient.

We expect the energy delivered per residential customer to be impacted by the decrease in gas demand by residential customers as they progressively switch their household appliances from gas to electric. The extent to which this results in an increase in the energy delivered is uncertain, as improvements in appliance efficiency, and rooftop solar and battery storage will decrease the necessity of energy being sourced from the grid.

3.2.2 Network utilisation to change with energy transition

Our current network utilisation performance reporting measures the extent that network assets are used to meet customer demand. We calculate utilisation by dividing an NSP's non-coincident maximum demand[46] by the total capacity of its zone substation transformers.

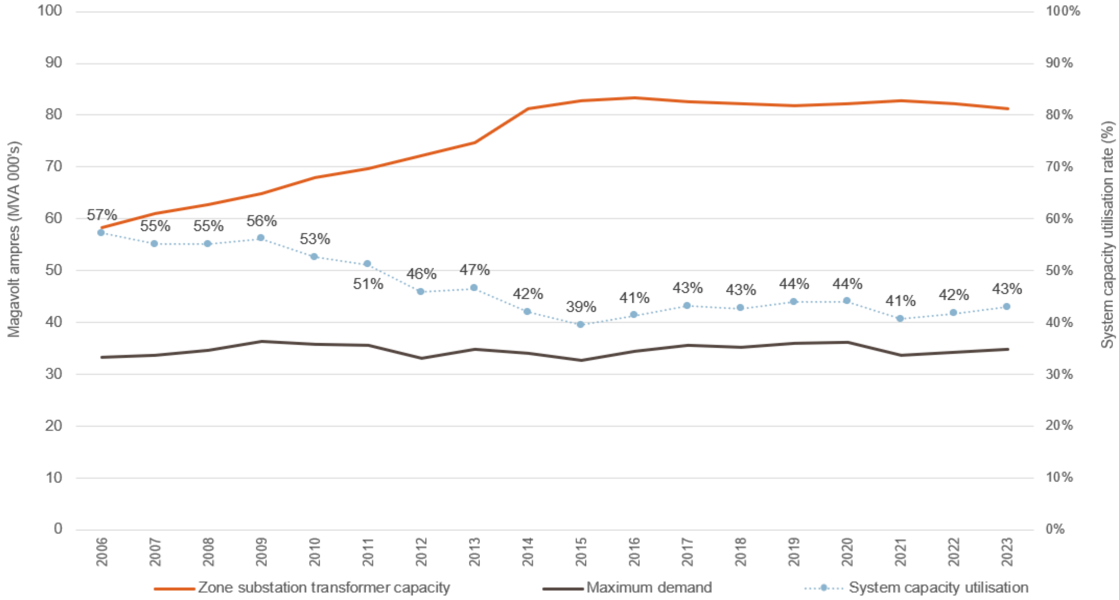
This utilisation measure is an informative but incomplete measure of a network's ability to respond to increases in maximum or peak demand on the network. Low utilisation (i.e., high spare capacity) means a network can service large increases in peak demand. However, low

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

utilisation may also mean customers are paying for network assets they rarely use, questioning whether the capex investment was an efficient cost.

The zone substation transformer capacity, maximum demand and utilisation have all been relatively flat since 2014, which coincides with a steep decrease in augmentation expenditure.[47] This is resulting in our current measure of network utilisation remaining consistent with previous years.

Figure 3-21 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 zone substation level' MVA measure. 'Zone substation 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 Zone substation transformer capacity.

As noted above, this measure is incomplete, as it does not account for two-way network flows and may not show localised constraints from exports from solar photovoltaic (PV) systems. These constraints are becoming more prevalent as more consumers install solar PV systems, requiring DNSPs to possibly limit CER being exported into the grid to protect network assets.

We are currently participating in a stakeholder reference group lead by the University of Technology Sydney on Reimagining Network Utilisation in the Era of Consumer Energy Resources to develop improved measures of network utilisation, which may be included in future versions of this report. Measures of utilisation are further complicated by the different de-rating factors that networks may apply to their reported substation transformer capacities.

The issue of whether network assets are being effectively utilised, was raised by Energy Network Australia in their The Time is Now report, which developed an "all levers pulled" scenario, which involved:[48]

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47 AER. Electricity network performance report, September 2020, p 20.

48 Energy Networks Australia, The Time is Now, August 2024, p 8.

- 7 GW of additional community generation by 2030, consisting of smaller scale renewable generation plants connected to the distribution networks.
- 5 GW of additional rooftop solar by 2030 installed on commercial and industrial facilities and residential premises (with a focus on rental properties and low-income households).
- 5 GW of distribution connected battery storage by 2030 installed by utilising existing available land and connection points and making these available to consumers via the distribution network and third-party partnerships.
- 1 million more electric vehicles on the road by 2023.
- greater coordination of CER.

This report highlights that the distributions networks can do more 'heavy-lifting' in the energy transition. This is a proposition that can benefit consumers, as use of existing network asserts in lieu of new infrastructure investment will lead to lower future network costs.

It is imperative that consumers believe the existing infrastructure is being used effectively and that any unnecessary infrastructure investment is being avoided. This reinforces the need that any new infrastructure investment to improve network utilisation is efficient and providing the lowest network costs or potential energy service possible for consumers.

To compliment this efficient investment, the rollout of smart meters will provide more network visibility to distribution networks. By having more timely and granular data of consumer's consumption patterns, networks will be able to manage constraints from localised peak demands on their networks. This is an example of the data that can be used to create non-network solutions that avoid unnecessary capital investment.

3.2.3 Supply reliability within an electricity distribution networks control continues to improve

Supply reliability is a key network service outcome. We measure reliability based on the frequency and duration of interruptions to customer supply.

We report 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 those 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.

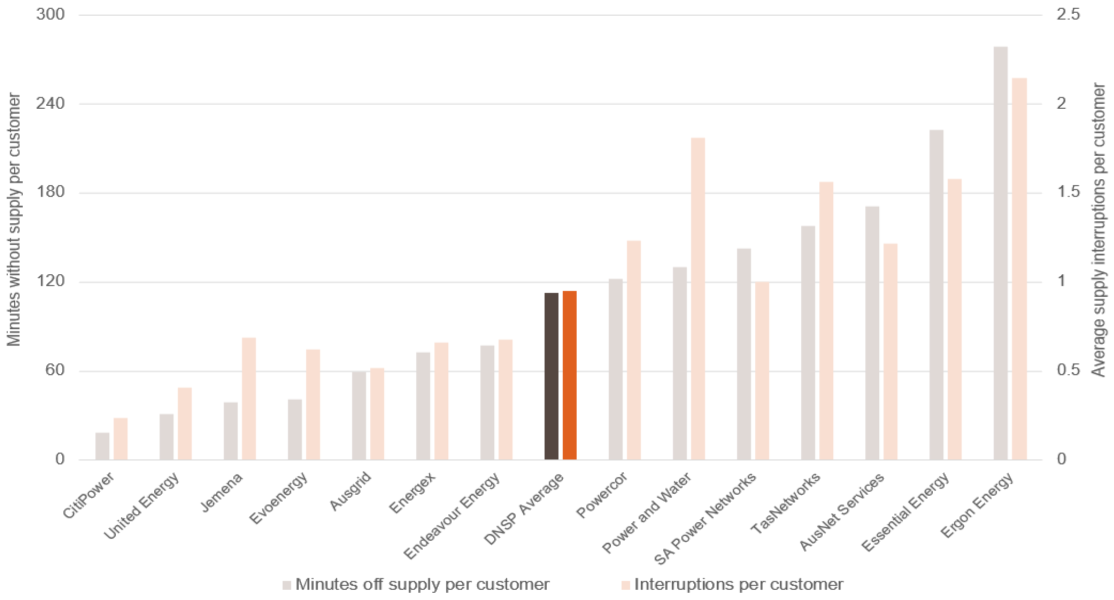
Networks are incentivised to decrease SAIFI and SAIDI through the service target performance incentive scheme (STPIS) (see above). The STPIS incentivises networks to improve reliability where the value of the extra reliability to customers exceeds the capex or opex costs of providing the improved reliability.

Reliability data for all NSPs is provided in the datasets that are published alongside this report. In this report, we focus on DNSP reliability, as they tend to be the primary source of supply interruptions.

Including natural disasters, planned outages and other interruptions, in 2023 the average DNSP customer experienced 1.4 outages, for a total time without supply of 360 minutes. When normalised for SAIDI and SAIFI, the average DNSP customer experienced an average of 0.9 outages, for an average duration of 113 minutes without supply.

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

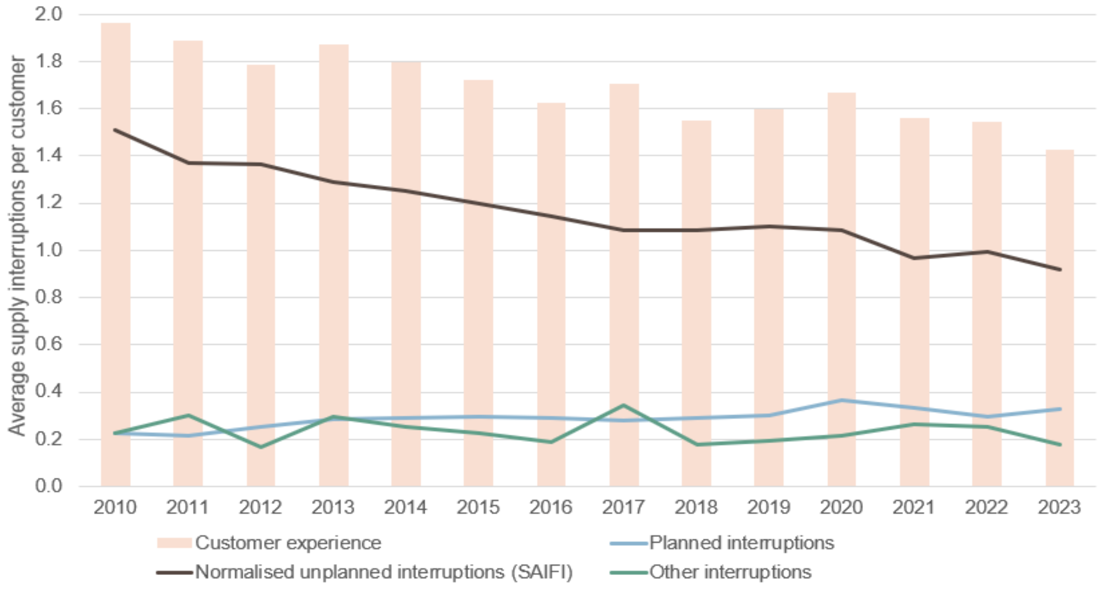
Figure 3-22 Customer outages - DNSPs - 2023



Sources: Minutes off supply per customer is from 'whole of network unplanned SAIDI excluding excluded outages' from EB RIN table 3.6.1 'Quality of Services - Reliability.' Interruptions per customer is from 'whole of network unplanned SAIFI excluding excluded outages' from EB RIN table 3.6.1 'Quality of Services - Reliability.'
Note: DNSP Average of minutes off supply and interruptions per customer calculated by weighting individual DNSPs minutes off supply and interruptions per customer by DNSP's customer numbers.

In 2023 customers experienced the lowest number of outages, both as measured by SAIFI and in absolute terms.

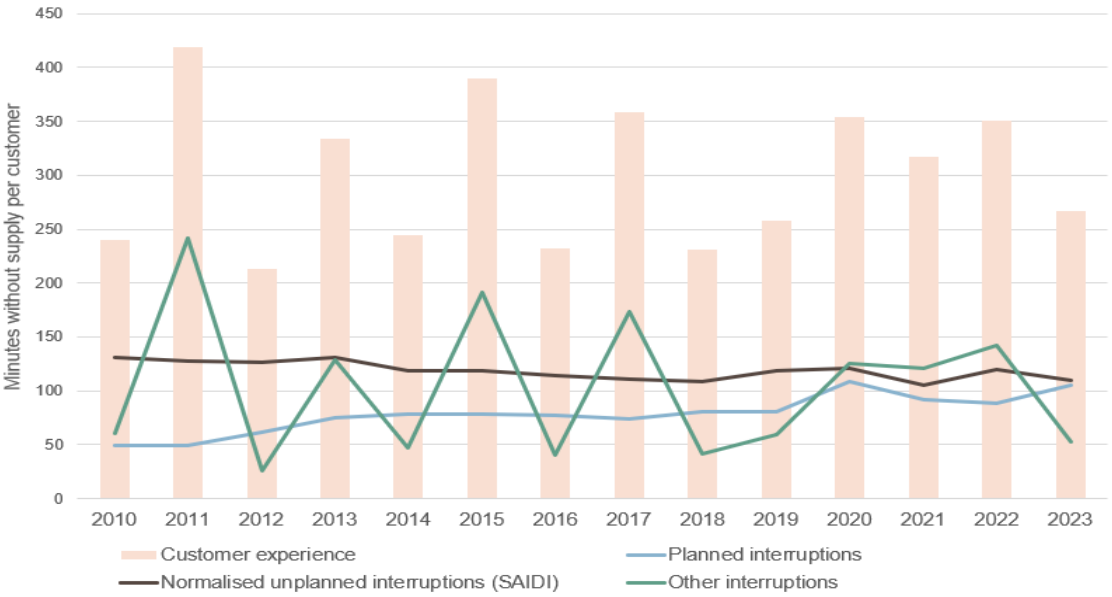
Figure 3-23 Frequency of outages - DNSPs



Source: Category Analysis RINs, AER analysis.
Notes: Data reflects interruptions to supply that lasted longer than 3 minutes consistent with the definition of a sustained interruption in STPIS version 2.0 (November 2018). This differs from the 1- minute threshold in STPIS version 1.0 (May 2009). Years reflect regulatory years.

In 2023 there was also a decrease in the duration of SAIDI outages, with a corresponding decrease in the customer experience outages.

Figure 3-24 Duration of outages - DNSPs



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

3.3 Smart meter rollout expected to increase in future years

In 2023, coordinating and installing 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 consumers.

Due to delayed rollout of smart meters outside of Victoria, the Australian Energy Market Commission (AEMC) undertook a review into the regulatory framework for metering services. The AEMC's final report[49] made several recommendations, which most noticeably included establishing an acceleration target of reaching universal deployment and uptake of advanced meters in the NEM by the end of 2030. A rule change process is taking place to give effect to these recommendations.[50]

To achieve this target, the AEMC proposed that electricity DNSPs commence planning to replace its fleet of legacy accumulation and interval (type 5 and 6) meters by 2030. Under that retirement plan framework, each electricity DNSP would be required to develop a 5-year schedule (with yearly interim targets) to dispose of these accumulation and interval meters.[51]

The recommendations of the AEMC will not be implemented until 1 July 2025 (the 2026 regulatory year) or when the AEMC's changes are implemented in the NER.[52]

The accelerated rollout recommended by the AEMC is based on their findings of the significant net benefits from universal uptake, that will reduce network costs which are charged to consumers by:

- reducing costs for routine and special meter readings and meter installations, and
- enabling DNSPs to de-energise and re-energise premises remotely.

Further, the AEMC notes 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.[53]

Due to the benefits smart meters will provide electricity DNSPs and consumers in future years, we will continue to report on the progress of the rollout and how the purported benefits are being realised by consumers.

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49 AEMC, Final Report - Review of the regulatory framework for metering services, August 2023.

50 A draft rule was made in April 2024 in relation to the recommendations from the AEMC's smart meter review.

51 AEMC, Final report - Review of the regulatory framework for metering services, August 2023, p i.

52 In addition to the AEMC's recommendations, our recent 2024-29 final determinations for NSW, ACT and Tasmanian DNSPs made varying determinations in relation to the treatment of legacy meters. Further information can be found in the metering services attachment of each DNSPs final determination.

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

3.3.1 Steady increase in smart meters installed in 2023

We report 'smart meters' as the sum of Type 4 and Type 5 meters.[54] These do not include accumulation meters, which are still a significant portion of the meters used outside Victoria.

Accumulation meters are 'count up' meters which measure how much energy is consumed over a period, but not the time of day. Smart meter installations are currently triggered by upgrades from single to 3 phase connections, solar PV installations, replacements of old accumulation meters and new connections. Type 5 meters are more limited than type 4 meters only allowing time of use pricing.[55]

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

Like last year, 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, with on average 99.6% of residential customers with a smart meter and 97.2% of non-residential (low voltage) customers having a smart meter.

The highest installations of smart meters for residential customers are in Tasmania, where the state government has made commitment that the smart meter rollout would be completed by the end of 2026.[56] The next highest jurisdiction was NSW,[57] with the other jurisdictions ranging from approximately 35% to 40% of smart meter installations for residential customers.

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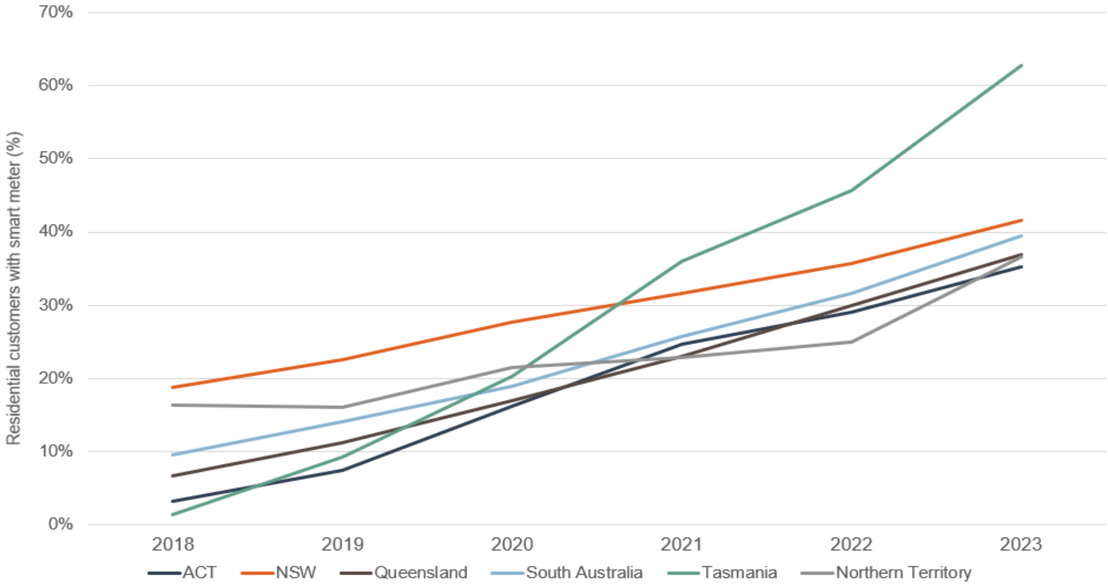
54 While Type 1-3 meters are also smart meters, these are only available to large customers. We do not report on large non-residential customers in this appendix as they have full smart meter penetration.

55 Although considered 'smart meters' for our analysis, 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.

56 Aurora Energy, Advanced meter rollout - everything you need to know, February 2023, p 1.

57 The high proportion of smart meters in NSW are due in part by Ausgrid's type 5 meters which are classified as being 'smart meters' in our reporting. These meters are being replaced as part of the AEMC's recommendations for the rollout of smart meters. At the end of the 2023 regulatory year, Ausgrid had 265,923 residential type 5 meters and 69,809 non-residential low voltage type 5 meters.

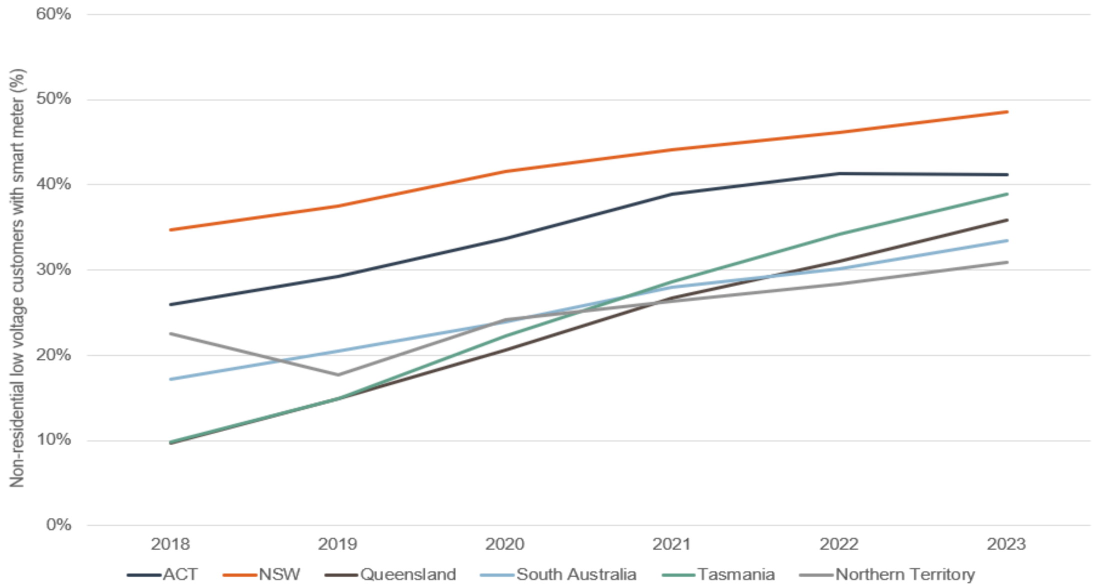
Figure 3-25 Residential customers with a smart meter



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.

In comparison for non-residential (low voltage) customers, NSW has the highest proportion of smart meters installed, which is followed by the ACT. All other jurisdictions range between 30% to 40% of smart meter installations for non-residential low voltage customers.

Figure 3-26 Non-residential (low voltage) customers with a smart meter

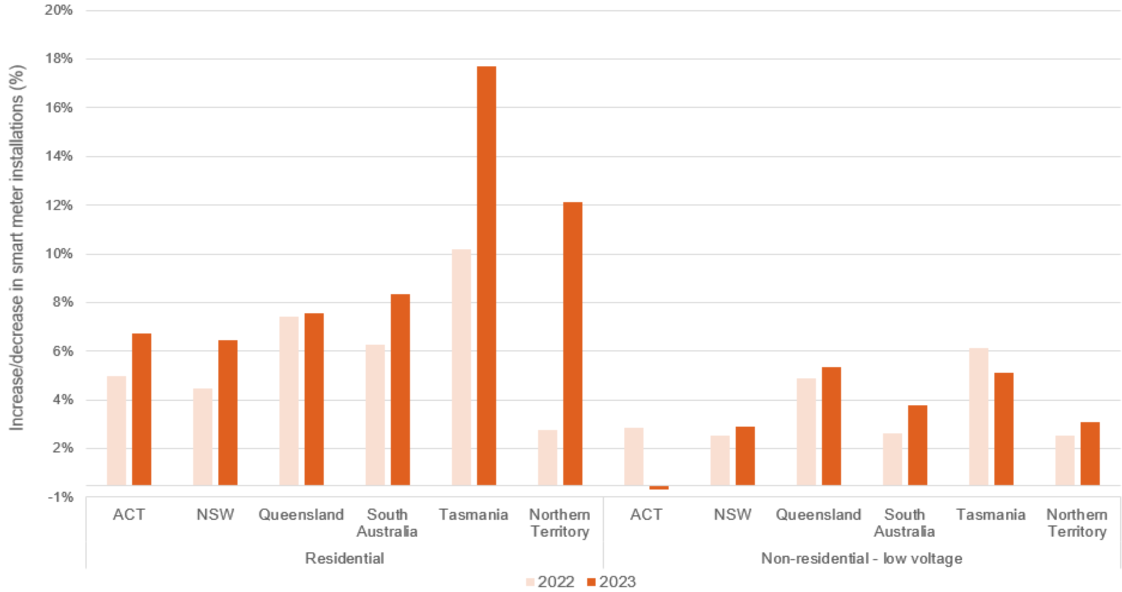


Source: Non-residential (low voltage) smart meters: Annual RIN, 'Table P1.1 - Distribution customers numbers by meter type' – non-residential - low voltage - Type 4 and 5 meters.
Note: Proportion of smart meters installations for non-residential (low voltage) customers calculated by dividing the non-residential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

In comparing smart meter installations in 2022 to 2023, there has been an increase of at least 6% for residential customers in all jurisdictions, with considerable increases in

Tasmania and the NT. This contrasts to non-residential (low voltage customers), where no jurisdiction had an increase of more than 5%, and the ACT had a decrease in their smart meter installations.

Figure 3-27 Residential and non-residential (low voltage) customers with a smart meter



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.

4 Gas distribution network operational performance

This chapter focuses on the performance of gas DNSPs for the 2023 regulatory year. We plan to report on gas TNSPs in a separate report in the second half of 2024. References to NSPs in this chapter relates to gas DNSPs and TNSPs.

The 2023 regulatory year was between 1 July 2022 and 30 June 2023 for all gas NSPs, except for the Victorian gas DNSPs (AGN Victoria, AusNet Services and Multinet Gas) which had a 2023 regulatory year between 1 January 2023 and 30 June 2023.

In this chapter data for AGN Victoria, AusNet Services and Multinet Gas have been "annualised" to account for their shorter regulatory year.[58] Annualising the data of these gas DNSPs allows for the data to be compared to other gas DNSPs and to previous access arrangements.

Our approach for annualising for AGN Victoria, AusNet Services and Multinet Gas is the same approach used for annualising data for Victorian electricity DNSPs for their 2021 regulatory year, which was also for a six-month period (1 January to 30 June 2021). This involves multiplying the six-month data by the number of days in a full regulatory year (365 days) divided by the number of days from 1 January to 30 June (181 days).[59] This approach has impacted the 2023 data for Victorian DNSPs, most noticeably in the gas delivered and UAFG, and therefore stakeholders should be cautious about making any significant conclusions from the data.

Following the recent reforms to gas pipeline regulation,[60] the previous three forms of regulation (full regulation or light regulation for covered pipelines and Part 23 NGR regulation for uncovered pipelines) have been condensed into 2 forms of regulation. Under the new regulatory framework, gas pipelines are classified as either "scheme" or "non-scheme pipelines."

For our network performance reporting, references to gas NSPs are the scheme pipelines that were previously classified as 'full regulation.' These are the 9 gas NSPs we included in our last year's report. Background information on these 9 gas NSPs and how they are regulated is available in Chapter 6 of State of the energy market 2023 report.

58 The data is adjusted to account for the shorter regulatory year by dividing by the number of days in the shortened year (181) and then multiplying by the number of days in the longer regulatory year (365). This means annualised numbers are approximately double what the Victorian gas DNSPs reported for the reduced regulatory year.

59 This is calculated as the six-month data * (365/181).

60 Australian Government, Reform package to improve gas pipeline regulation takes effect, Department of Climate Change, Energy, the Environment and Water, accessed 13 June 2023.

4.1 Gas demand uncertainty continues to impact gas distribution networks

In November 2021, we published an issues paper, Regulating gas pipelines under uncertainty. This discussed the potential implications of a decarbonised future energy mix on the long-term gas demand forecasts and therefore the expected economic lives of gas distribution and transmission networks.

This paper addressed the issues we will face when making future access arrangement determinations for NSPs. The paper included an evaluation of potential options, including their costs and benefits, for managing the pricing risk and stranded asset risk for consumers and DNSPs that may arise from a potential material decline in gas demand in the future.

In addition, state and territory governments are already implementing measures to reduce residential and small commercial customers reliance on gas. This is seen through:

- the ACT Government in November 2023 introducing a regulation to prevent new gas connections for all residential buildings, commercial land-use zones, and community facility zones[61]
- the Victorian Government releasing its Gas Substitution Roadmap to help Victoria reduce the cost of energy bills and cut carbon emissions. Victoria has committed to halve emissions by 2030 as an early step towards meeting the national target of net zero emissions by 2050[62]
- the Victorian Government announcing that since January 2024 all new homes requiring a planning permit are required to be all-electric. This means new homes and residential subdivisions that require a planning permit cannot connect to the gas distribution network[63]

The impact of gas demand uncertainty is omnipresent in our gas performance reporting, as it touches on each NSP's revenues, expenditures, the valuation of their network assets and their gas delivered. This impact will increase in future years, as we transition towards a decarbonised future energy mix and state and territory governments implement new measures to assist the transition.

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61 ACT Government, Regulation to prevent new gas connections starts in December, media release, November 2023.

62 Victorian Government, Victoria's gas substitution roadmap, Department of Energy, Environment and Climate Action, accessed 21 March 2024.

63 Victorian Government, Victoria's gas substitution roadmap, Department of Energy, Environment and Climate Action, accessed 21 March 2024.

4.2 Customers continue to pay less for gas distribution services

4.2.1 Revenue and revenue per customer in real terms at their lowest in our dataset

The DNSPs are monopoly business that distribute gas to residential customers, commercial businesses, and industries. These NSPs are 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[64] for the access arrangement period for the NSPs. The X-factors along with actual inflation, changes in demand and other factors constrain annual prices 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.

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.[65] 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 2023, customers paid an average of $318 to the DNSPs. This is a decrease of $36 when compared to 2022 in real terms, or a decrease of $13 in nominal terms. In total, DNSPs recovered $1.4b from customers, 9.4% less in real terms than the previous year. Historically the revenue recovered and revenue per customer in real terms in 2023 was the lowest in our DNSP operational performance dataset.

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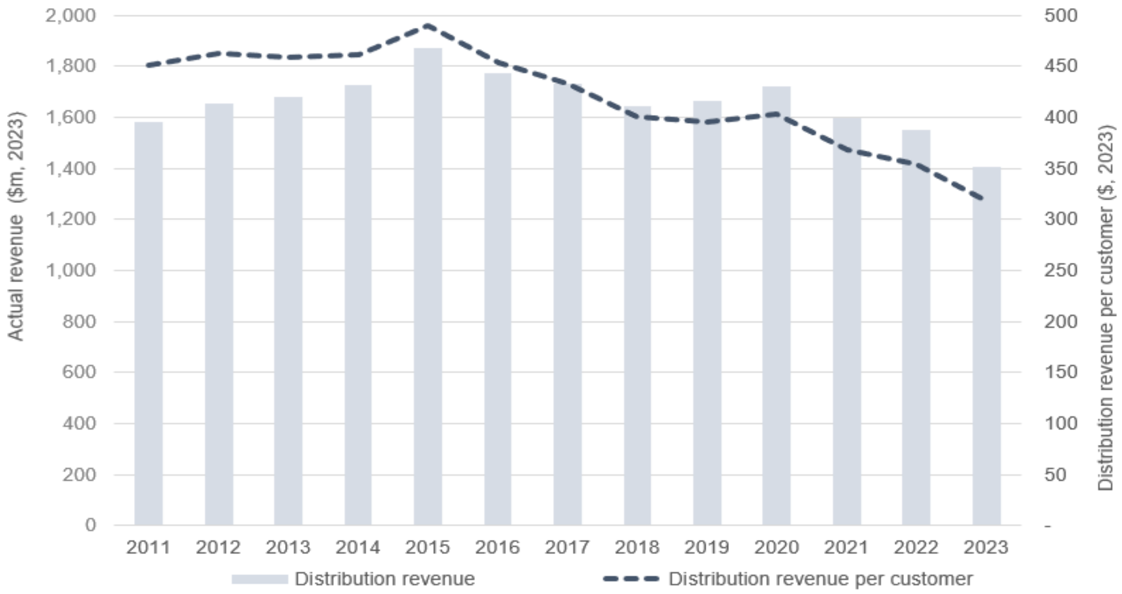
64 The X-factor is used with CPI to smooth the revenue an NSP will collect each regulatory year. This X-factor is an input in the control formula applied in annual pricing and is the change in real revenue/price from year-to-year. The X-factor is updated annually for changes in the allowed return on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

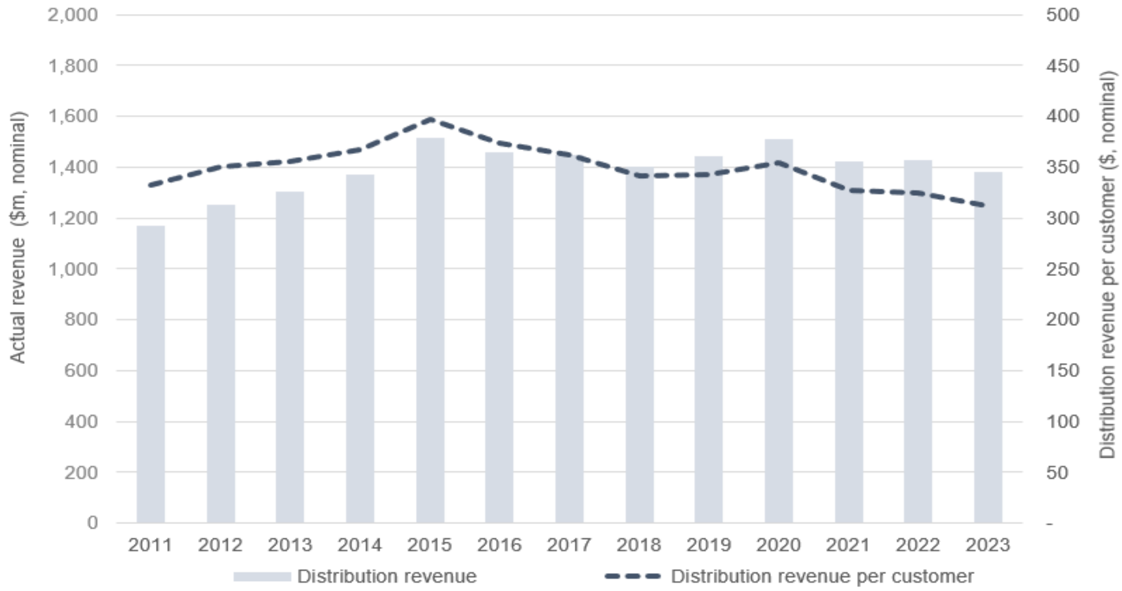
65 This difference is more pronounced between DNSPs and TNSPs. This is due TNSPs having a higher proportion of large customers with bespoke commercial arrangements, TNSPs (particularly Amadeus and RBP) provide a higher proportion of non-reference services. As noted above, this version of the 2024 Electricity and gas networks performance report does not include information on TNSPs.

Figure 4-1 Distribution revenue and revenue per customer - DNSPs - $ real 2023



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 2023 terms. Distribution revenue per customer calculated by dividing DNSP's distribution revenue by DNSP's customer numbers.

Figure 4-2 Distribution revenue and revenue per customer - DNSPs - $ nominal



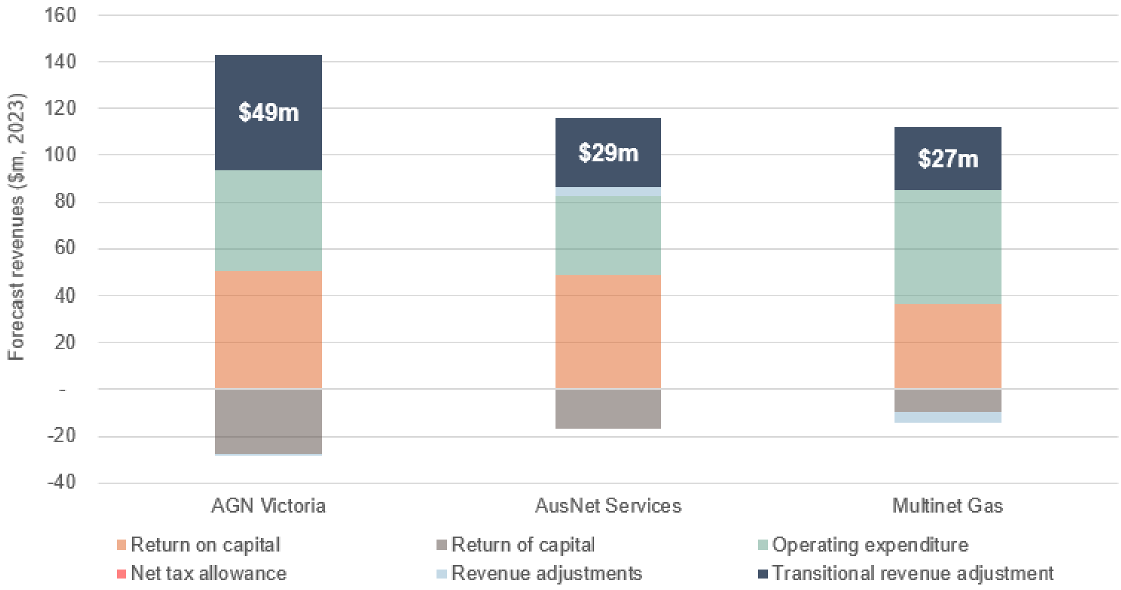
Source: Distribution revenue: Annual RINs - F3.1 Reference services, Customer numbers: Annual RINs - S1.1 Customer numbers by customer type.
Note: AER calculation to convert into $ mid-year nominal terms. Distribution revenue per customer calculated by dividing DNSP's distribution revenue by the DNSP's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

4.2.1.1 Revenue impacted by Victorian gas distribution network's extension period

The 2023 regulatory year for the Victorian 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.[66]

The revenue set for the extension period for AGN Victoria,[67] AusNet Services[68] and Multinet Gas[69] involved extending their tariff prices from the 2022 regulatory year with an adjustment for inflation. This decision to maintain the tariff prices in real terms for the 2023 regulatory year, created a revenue adjustment. This resulted in expected revenues for all Victorian DNSPs which were materially (51%) above the approved building block model.

Figure 4-3 Forecast revenues - Victorian DNSPs - extension period - $ real 2023



Source: Building block revenue from PTRM for HY2023 Final Decision 'Revenue Summary" for AGN Victoria, AusNet Services and Multinet Gas.
Note: AER calculation to convert to $ June 2023 terms.

The $49m (AGN Victoria), $29m (AusNet Services) and $27m (Multinet Gas)[70] which was cumulatively over-collected will be returned to customers in each Victorian DNSP's 2023-28 access arrangement, through the revenue adjustment building block. Due to this, the under collection over the next five regulatory years will not appear in the comparison of actual and forecast revenue. However, these revenue adjustments will impact the financial performance

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66 This was done though the Order in Council being made by the Victorian Minister for Energy, Environment and Climate Change under section 64 of the National Gas (Victoria) Act 2008 (Vic) that was published in the Victorian Government Gazette G39 30 September 2021. This amended the commencement date for the 2018-22 access arrangements to 1 July 2023.

67 AER, Final decision: AGN Victoria gas distribution access arrangement - 1 January to 30 June 2023 extension period, November 2022, p 4.

68 AER, Final decision: AusNet Services gas distribution access arrangement - 1 January to 30 June 2023 extension period, November 2022, p 4.

69 AER, Final decision: Multinet Gas distribution access arrangement - 1 January to 30 June 2023 extension period, November 2022, p 4.

70 This amount will be adjusted by interest at the regulatory WACC to maintain the time value of the money and ensured the net present value of the revenue adjustment.

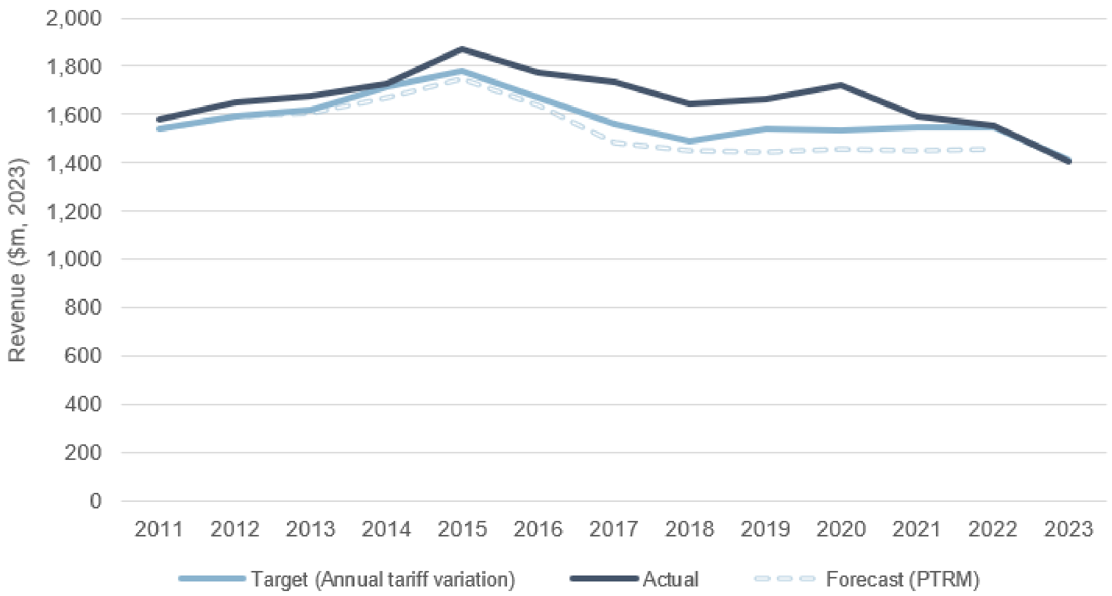
for these DNSPs, as the transitional revenue adjustment will drive a higher RoA and RoRE in 2023, before reducing these returns across their next access arrangement.

4.2.1.2 Updated datasets for gas distribution forecast revenue

In last year's report, we noted that there had been outperformance on revenue by DNSPs. In the operational performance dataset for 2023, we have followed a similar process to electricity NSPs and substituted forecast revenues from PTRMs with target revenues from the DNSP's annual tariff variation models. This change was to encompass the impact of X-factors and annual inflation which are included in tariff variation models when assessing any potential revenue outperformance by DNSPs.

Using the updated dataset, we note that there is a smaller discrepancy between actual and target revenues, as compared to actual and forecast revenues.

Figure 4-4 Target, forecast and actual revenues - DNSPs - $ real 2023



Source: Distribution revenue (Actual): Annual RINs - F3.1 Reference services. Target revenue - Annual tariff variation - DNSP annual tariff variation model, where not available PTRM - 'Revenue summary - Building block components. Forecast PTRM - 'Revenue summary - Building block components.'
Note: AER calculation to convert to $ June 2023 terms.

This variance decrease is due to the target revenue in the annual tariff variation models being determined using the actual demand from two year's prior and not the forecast demand determined in our access arrangements. Due to this, any outperformance from demand forecast when comparing the target revenue and actual revenue may not be apparent.

Our issues paper for the Review of gas distribution network reference tariff variation mechanism and declining block tariffs investigated gas demand outperformance in DNSP's over recoveries from their PTRM forecast revenues. This issues report noted that gas distribution networks are incentivised to outperform their demand forecasts under weighted average price cap regulation and that revenue over recovery derives from actual demand being higher than forecast volumes.[71]

This issues paper highlighted that our gas demand forecasts are dependent on factors which are external to the regulatory framework. These include the differing economic conditions across the various jurisdictions, demand, and supply balances in markets for products which have natural gas as either an input or a fuel, and changes in the appliance mix (gas or electricity) in consumer residential and commercial premises. The report also noted that although gas demand forecasting is inherently uncertain, we may be approving demand forecasts that are too low.[72]

Revenue outperformance is also attributable to JGN's recovery of additional revenue during their 2015-20 access arrangement. This recovery was due to several factors including demand outperformance, tariff variations and the limited merits review process and application of interim enforceable undertakings to set how JGN's revenues and tariffs were determined.[73]

4.2.2 Gas distribution networks made small incentive scheme payments in 2023

The incentive schemes for NSPs differ from those for electricity NSPs as they target efficiency gains and reducing costs from capex and opex, but not service outcomes or reliability.[74] This is designed to deliver better outcomes for customers and promote achievement of the NGO.

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 2023, no revenues from incentive schemes were earned by DNSPs, but rather $2m of payments were incurred. This was a decrease of $7m in real terms from 2022.

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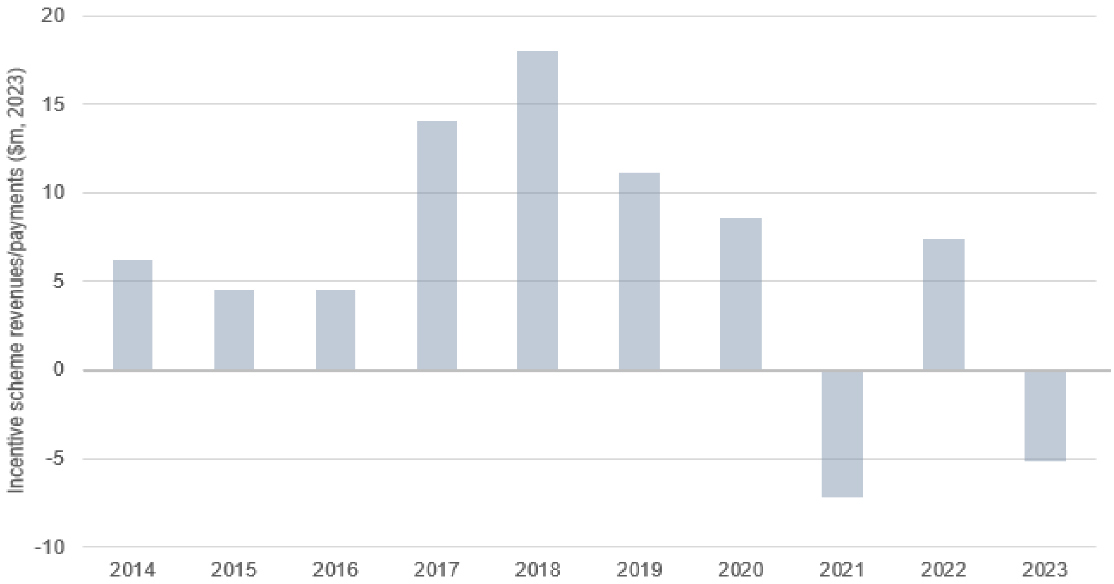
71 AER, Issues paper: Review of gas distribution network reference tariff variation mechanism and declining block tariffs, May 2023, pp 14-15.

72 AER, Issues paper: Review of gas distribution network reference tariff variation mechanism and declining block tariffs, May 2023, p 15.

73 Refer to our 2021 Gas network performance report for further discussion.

74 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 Revenues/payments from incentive schemes - DNSPs - $ real 2023



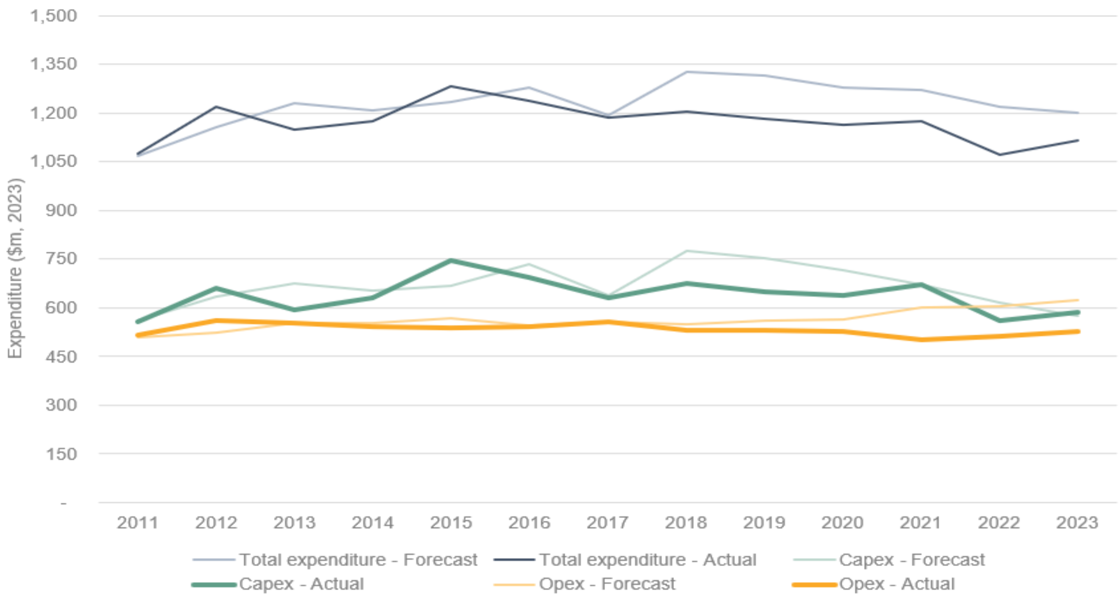
Source: Incentive scheme revenues/payments from Annual RIN table F3.6 Revenue - Rewards and penalties from incentive schemes. Where incentive schemes revenue/payments are not available, data is from respective DNSP's PTRM, 'Revenue adjustments.'
Note: AER calculation to convert to $ June 2023 terms.

4.2.3 Increase in expenditures driven by increase in opex and slight overspend in capex allowance

The expenditures for gas NSPs are the same as electricity NSPs; opex is for day-to-day business expenditures, whilst capex is spent on gas infrastructure, most commonly mains and connections network assets. The opex and capex is also recovered in the same manner as electricity NSPs, with forecasts determined by the AER to incentivise efficiency gains and outperformance, which will lead to lower forecasts in future years and lower network costs for customers.

In 2023, DNSPs had less expenditure than forecast, with in real terms a 15% underspend in opex and a 2% overspend in capex. In comparison to last year, in real terms capex increased by 5% and opex increased by 3%.

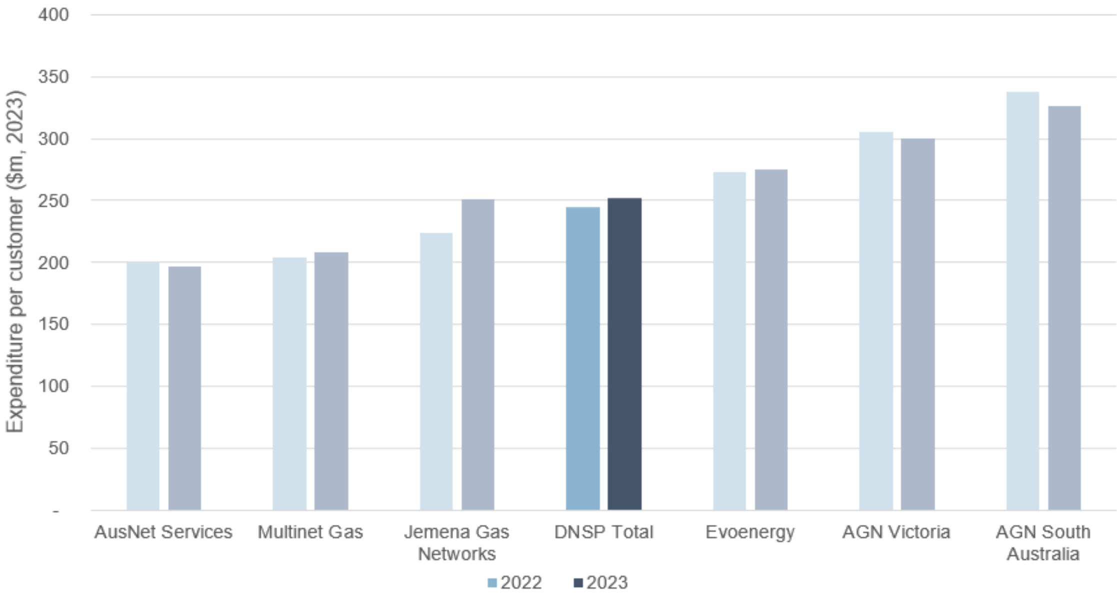
Figure 4-6 Total Expenditure - DNSPs - $ real 2023



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 2023 terms. Net capex is gross capex less capital contributions and disposals. Actual and forecast total expenditure is the sum of capex and opex.

The expenditure on a per customer basis in 2023 for DNSPs is similar to last year, with an average per customer increase in real terms of $7. This has been primarily driven by Jemena Gas Network's per customer increase of $28 in real terms through an increase in their opex during 2023.

Figure 4-7 Expenditure per customer - DNSPs - $ real 2023



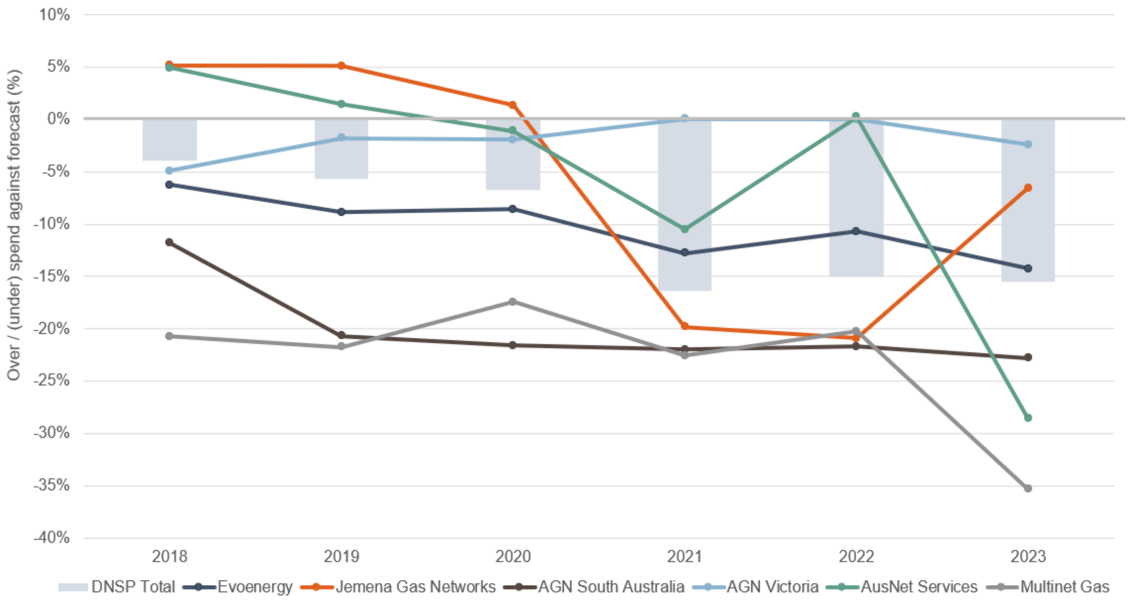
Source: Actual capex RFMs - RFM input - actual capex, actual asset disposal, actual capital contributions, or where not available in an RFM, annual RINs - F2.4 Capex by asset class, F2.5 Capital contributions by asset class, F2.6 Disposals by asset class. Actual opex: Annual RINs - F4.1 Opex by purpose. Customer numbers: Annual RINs - S1.1 'Customer numbers by customer type'.
Note: AER calculation to convert to $ June 2023 terms. Net capex is gross capex less capital contributions and disposals. Expenditure per customer calculated by dividing the DNSP's capex and opex by their customer numbers.

The expenditure per customer also highlights the different geographical region in which the DNSPs operate. This is discussed below in relation to the CAB per customer, however it highlights that DNSPs incur more expenditure on a per customer basis when distributing to customers over a bigger geographical area.

4.2.3.1 Gas distribution networks continue to underspend on their opex allowance

In 2023, DNSPs had opex of $526m, an increase in real terms of $13m or 3% from 2022. There have been 6 consecutive cumulative underspends by DNSPs (from 2018 to 2023), for a collective underspend in real terms of $377m.

Figure 4-8 Opex - DNSPs - $ real 2023



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 2023 terms. Opex over/under calculated by comparing actual opex against forecast opex for respective regulatory year

Two of the most notable opex underspend are from AGN South Australian and Multinet Gas, both of which may be attributable to cost savings from transactions which purchased the businesses in 2014 and 2017 respectively.[75] These transactions can enable lower operating and administrative costs, as their corporate groups can achieve greater economies of scale.

This opex efficiency benefits both NSPs and consumers and is a key feature of our incentive based regulatory framework. The outperformance enables NSPs to earn returns greater than their allowed returns and decreases opex forecasts in future access arrangements.

4.2.3.2 Drivers of capex remain connections and mains replacements

Our regulatory framework requires NSPs to undertake capital investment to efficiently deliver the reference service safely and reliably to customers. Due to this, the required annual capex for each DNSP will be dependent on the new connections required, the replacement of mains and meters, the augmentation of the networks, and other required costs.

Historically DNSPs have predominately had capital costs for new connections and mains replacements. The levels of connection expenditure have been driven by the number of new customers requiring a gas supply, whilst the mains replacement expenditure has been driven by the replacement of cast iron pipelines with pipelines using polyethene or 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 a previous year's report we noted that all DNSPs except Evoenergy had started their mains replacement at different times, with Jemena Gas Networks principally replacing their cast iron before 2011. This contrasts with AGN South Australia and the Victorian DNSPs,

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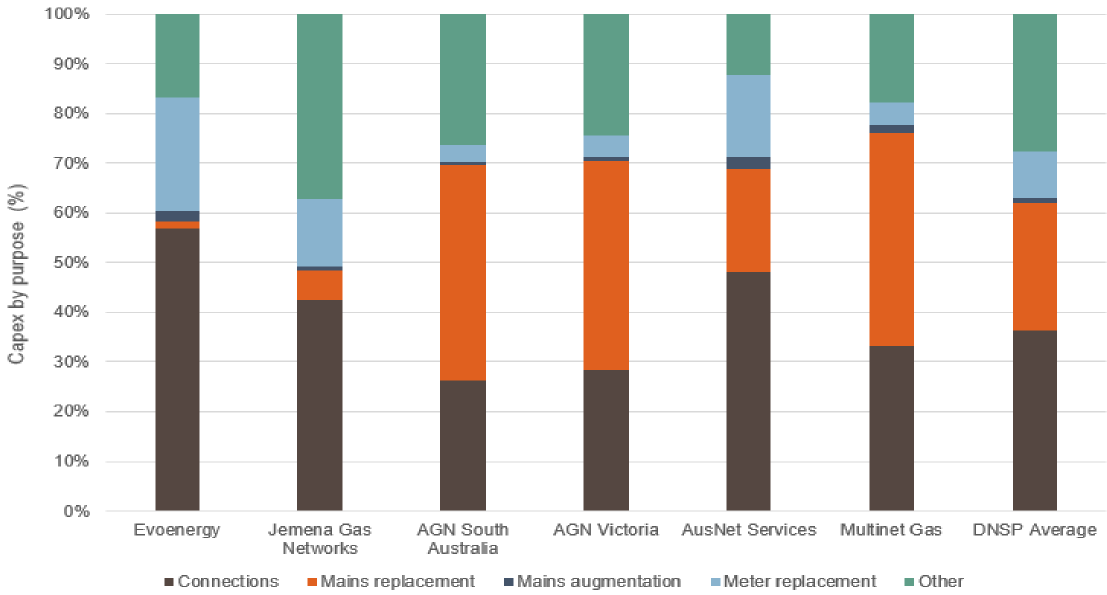
75 AER, 2021 Gas network performance report, December 2021, pp 70-71.

who are continuing their mains replacement programs in their current access arrangements.[76] Evoenergy's gas network was commissioned in 1982 using polyethene and polyamide materials, and therefore not had any cast iron pipelines.

The capex by purpose expenditure for 2023 illustrates the different stages of the mains replacement program for DNSPs, with a significant proportion of the capex of AGN South Australia, AGN Victoria and Multinet Gas being invested in mains replacement. This contrasts significantly with Evoenergy and Jemena Gas Networks where there has been minimal mains replacement capex spent.

Figure 4-9 Capex by purpose - DNSPs - 2023 - $ real 2023



Source: Capex by purpose: Annual RINs - E1.1.1 Reference Services.
Note: AER calculation to convert to $ June 2023 terms. Other consists of ICT, capitalised overheads, telemetry, and other capex.

The completion of the mains replacements program by AGN South Australia and the Victorian DNSPs will be reflected in the capex investment and additions to the CAB in future years.

4.2.3.3 Necessity of Victorian mains replacement programs

In our recent 2023-28 access arrangement for the Victorian DNSPs, a submission by the Brotherhood of St Lawrence questioned whether the expected decline in demand required a re-evaluation of the asset (main) replacement programs[77] which are either ongoing or nearing completion for the Victorian DNSPs.

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76 AGN South Australia, AGN South Australia - 2021-26 access arrangement proposal, p 3; AER, Attachment 5 - Capital expenditure - Final decision - AGN Victoria access arrangement 2023-28, June 2023, p 7; AER, Attachment 5 - Capital expenditure- Final decision - AusNet Services access arrangement 2023-28, June 2023, p 7; AER, Attachment 5 - Capital expenditure- Final decision – Multinet Gas access arrangement 2023-28, June 2023, p 7.

77 Brotherhood of St. Laurence, 2023-28 Victorian Gas Distributors' Access Arrangement, Draft decision and Revised Proposals, February 2023

We considered this in our access arrangement determinations[78] for each Victorian DNSP.[79] In our determinations we noted that gas networks have traditionally been run as growth assets with costs spread over a growing customer base. We stated that there were several factors that had changed the outlook of gas and that they were projected to slow demand growth and reduce the number of new gas customers.[80]

Our access arrangement determinations stated that there was no current policy in place governing our decision aimed at the decommissioning of the gas network in the short to medium term. Further, as mains replacement capex relates to stay-in business capex,[81] the purpose of which is to allow the service provider to safely operate the network and meet its licence obligations, the mains replacement programs were still required over the 2023-28 access arrangement.[82]

Our access arrangement determinations also highlighted that reliability and safety of supply are paramount factors under the NGR, and that transportation of gas needs to meet stringent safety requirements, with leaking gas causing a significant potential explosion risk as well as a high pollution concern. We also noted that unless safety standards are loosened, then mains replacement expenditures will be prudent, even in the context of falling demand. On this basis we concluded that it was prudent for DNSPs continue their mains replacement programs.[83]

Our access arrangement determinations are made to achieve the NGO, which requires us to promote efficient investment in, and efficient operation and use of, covered gas services for the long-term interests of consumers of covered gas with respect to:

a) price, quality, safety, reliability, and security of supply of covered gas; and

b) the achievement of targets set by a participating jurisdiction

    i) for reducing Australia's greenhouse gas emissions; or

    ii) that are likely to contribute to reducing Australia's greenhouse gas emissions.

These determinations highlight the difficulty in making future determinations for NSPs and achieving the NGO’s new consideration of greenhouse gas emissions in the absence of both:

- a policy governing the decommissioning of gas pipelines and

78 This issue was discussed in the capex final decision of all three Victorian Gas DNSPs. For referencing purposes, we have only included references for the capex final decision of Multinet Gas.

79 AER, Attachment 5 - Capital expenditure- Final decision – Multinet Gas access arrangement 2023-28, June 2023, p 7.

80 AER, Attachment 5 - Capital expenditure- Final decision – Multinet Gas access arrangement 2023-28, June 2023, p 10.

81 Stay in business capex relates to capex which is designed for a gas DNSP to safely operate their network and meet its licence obligations.

82 AER, Attachment 5 - Capital expenditure- Final decision – Multinet Gas access arrangement 2023-28, June 2023, p 11.

83 AER, Attachment 5 - Capital expenditure- Final decision – Multinet Gas access arrangement 2023-28, June 2023, p 11.

- a holistic approach to maintaining and replacing assets to meet the required safety levels as we possibly decommission gas pipelines[84]

These are issues that are not restricted to Victorian DNSPs, as we will also deal with these issues and others when considering greenhouse gas emissions in the access arrangement determinations for Jemena Gas Networks for 2025-30 and Evoenergy and AGN South Australia for 2026-31. These considerations will not be restricted to capex investments in the gas networks, but also involves NSPs possibly including expenditure that contributes to achieving emissions reduction targets in their regulatory proposals.[85]

We will continue to monitor the progress and completion of these mains replacement programs and their impact on capex and the CAB in future years.

4.2.4 CABs decrease in real terms from last year as stakeholders deal with gas demand uncertainty

For NSPs, the total economic value of the network assets they use to provide regulated network services is known as the CAB. The CAB will grow as NSPs replace their pipeline and other network assets or reticulate gas pipelines to new customer bases.

The size of the CAB for NSPs and in particular DNSPs is a significant issue with the uncertainty that exists around gas demand. Declining gas demand creates issues which may exacerbate in a short period of time, as expedited customers leaving the gas networks leads to an ever increasing ‘death spiral.’

The AER’s Regulating gas pipelines under uncertainty information paper, raised several issues[86] on the ramifications of falling gas demand and how it could result in:

- network costs being shared amongst few customers
- 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

One of the potential solutions to these issues 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 National Gas Rules,[87] which enable us to accelerate depreciation where necessary to allow cost recovery and generate efficient prices as new information becomes available.

84 The changes to the NGO were made in February 2024, whilst the final determination for the Victorian DNSPs were made in June 2023, therefore the NGO when making the determinations for the Victorian DNSPs did not include consideration of greenhouse gas emissions.

85 AEMC, Final determination - Harmonising the rules with the updated objectives, February 2023, p i.

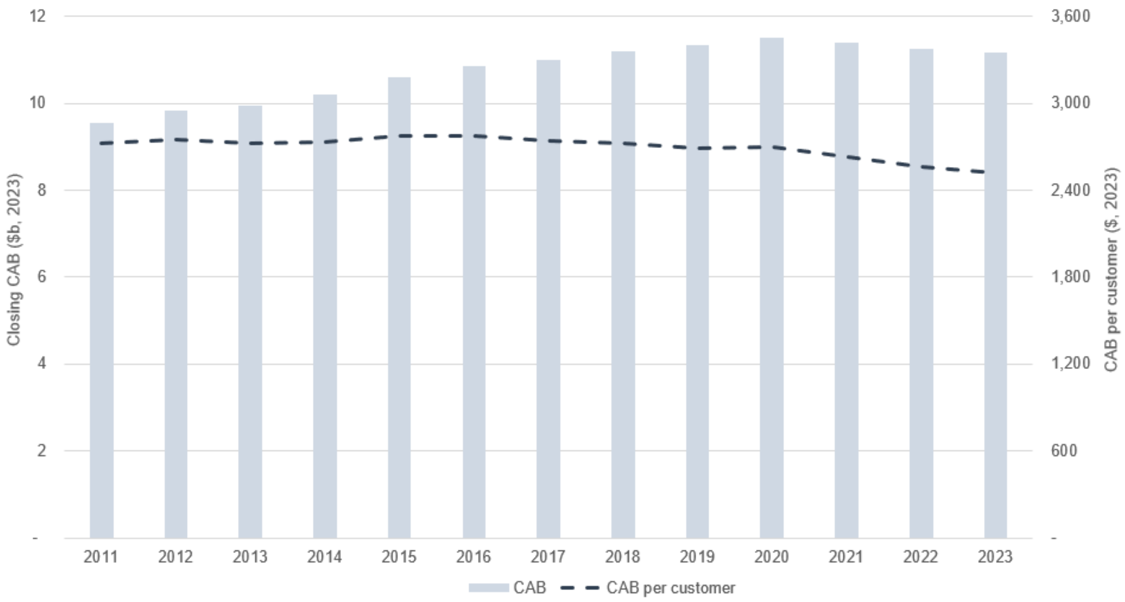
86 AER, Regulating gas pipelines under uncertainty: Information paper, November 2021, pp. 54-55.

87 NGR, r.89(1)(b) and r.89(1)(c).

Accelerated depreciation was considered recently in the AGN Victoria,[88] AusNet Services[89] and Multinet Gas[90] access arrangements for their 2023-28 access arrangement. The final determinations allowed for $333m[91] in accelerated depreciation across the three distribution networks as we balanced the necessity for accelerated depreciation with a 0% per annum real price change. This decision was designed to balance accelerated depreciation price impacts on customers with the uncertainty around demand forecasts and policy developments.

Although this accelerated depreciation will not be reflected in the CAB values until 2024, in 2023 there was a decrease in the value of DNSPs CABs in real terms by 0.9%, to a combined value of $11.2b. This continued a trend of declining CABs for DNSPs on real terms since 2020.

Figure 4-10 CAB - DNSPs - $ real 2023



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 2023 terms. CAB per customer calculated by dividing CAB by customer base.

4.2.4.1 CAB per customer correlates with network length

In last year's report we observed the correlation between CAB per customer and CAB per gas delivered for DNSPs.[92] In this we noted that AGN South Australia which distributed a

88 AER, Overview - Final decision - AGN Victoria access arrangement 2023-28, June 2023, p 22.

89 AER, Overview - Final decision - AusNet Services distribution access arrangement 2023-28, June 2023, p 23.

90 AER, Overview - Final decision – Multinet Gas access arrangement 2023-28, June 2023 p 23, June 2023, p 23.

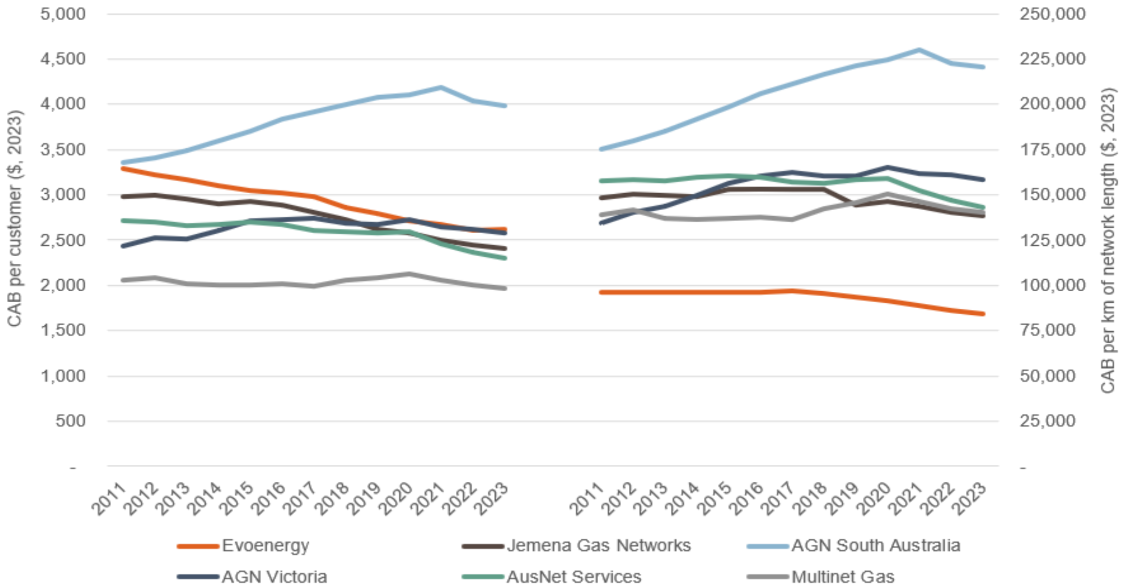
91 In June 2023 real terms.

92 AER, Gas network performance report 2023, December 2023, p 34.

higher proportion of gas to large business or industry had a higher CAB per customers and contrasts to other DNSPs which had declining or stagnant CABs per customers.

In our analysis, we have also considered CAB per customer and CAB per km of network length. This contrasts AGN South Australia and AGN Victoria with the other DNSPs who have seen both their CAB per customer and per km network length decrease over the operational performance dataset. For AGN South Australia and AGN Victoria their CAB per customer and per km network length have both increased in real terms since 2011, with the increases most pronounced for AGN South Australia.

Figure 4-11 CAB per customer / CAB per network length - DNSPs - $ real 2023



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'. Network Length: Annual RIN - N2.1 'Network Length - by pressure and type'
Note: AER calculation to convert to $ June 2023 terms. CAB per customer calculated by dividing the DNSP's CAB by the DNSPs customer base. CAB per network length calculated by dividing the DNSP's CAB by its network length.

This correlation is expected as networks which cover wider geographical and regional areas will require more investment in pipelines and have a small customer base to spread the CAB across.

AGN Victoria covers gas connections in the south and north of Victoria, including reticulations in Traralgon, Bairnsdale, Shepparton, and Wangaratta as well as gas connection in Albury. AGN South Australia's network covers Adelaide and its surrounds, and the regional centres of Mount Gambier, Whyalla, Port Pirie, Barossa Valley, Murray Bridge and Berri. The service to these customers and the extension to the regional areas with lower customer density has required investment by AGN Victoria and AGN South Australia which increases their CABs.

4.3 Victorian gas distribution network's extension period impacting metrics

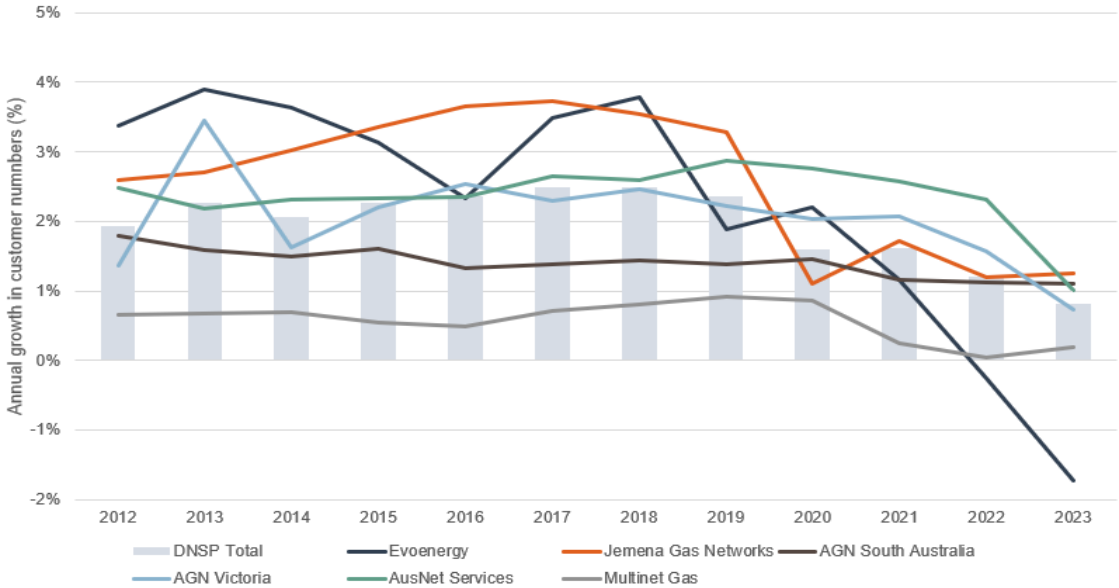
We report on customer numbers and the service outcomes that customers receive from their DNSPs being gas delivered, network outages and unaccounted for gas (UAFG).

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.

4.3.1 2023 has lowest growth in customer numbers

The gas demand uncertainty is evident in DNSP's customer numbers, with customer number growth[93] decreasing from approximately 2% from 2012 to 2020, to below 1% for 2023.

Figure 4-12 Customer numbers growth - DNSPs



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

The low growth in customer numbers for the Victorian DNSPs has been impacted by their six-month regulatory year, as this only reflects connections for this shorter period. However, based on the recent decision by the Victorian government to prohibit new homes from connecting to gas,[94] we expect 2024 to have similar or lower customer number growth for Victorian DNSPs.

A potential indication of the prohibition of new connections on customer number growth for Victorian DNSP's is evident in Evoenergy's annual customer decrease of 1.7% in 2023, following the ACT government's decision to stop new gas connections for all residential buildings, commercial land-use zones, and community facility zones.[95] In future years, we expect customer numbers to decrease from these government decisions and households removing their gas connections and electrifying their household appliances. This decrease

93 Customer numbers growth is determined by subtracting the number of disconnections from the number of connections.

94 Victorian Government, Victoria's gas substitution roadmap, Department of Energy, Environment and Climate Action, accessed 21 March 2024.

95 ACT Government, Regulation to prevent new gas connections starts in December, media release, November 2023.

will accelerate if other state governments make similar decisions to slow or stop gas connections to gas distribution networks.

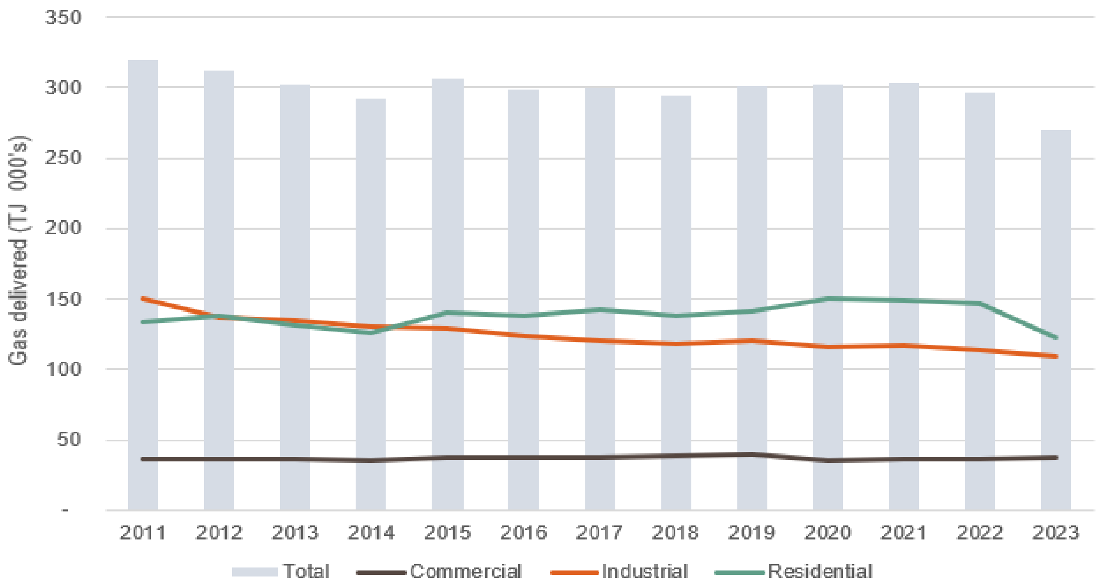
4.3.2 Gas delivered in 2023 should be treated with caution

Gas delivered annually can be dependent on several factors, ranging from customer preferences to government policy. We report on gas delivered by customer type to demonstrate the contribution of residential, commercial, and industrial customers to demand.

These factors are most relevant when assessing the gas usage of the different customer types, as demand changes from government policy changes, pandemic responses, and unexpected weather events, can change the quantity of gas delivered to each customer type.

In 2023 our operational gas delivery data indicates a 9% decrease in gas demand, a decrease from 297 thousand TJs to 270 thousand TJs across the six gas distribution networks.

Figure 4-13 Gas delivered - total and by customer type - DNSPs

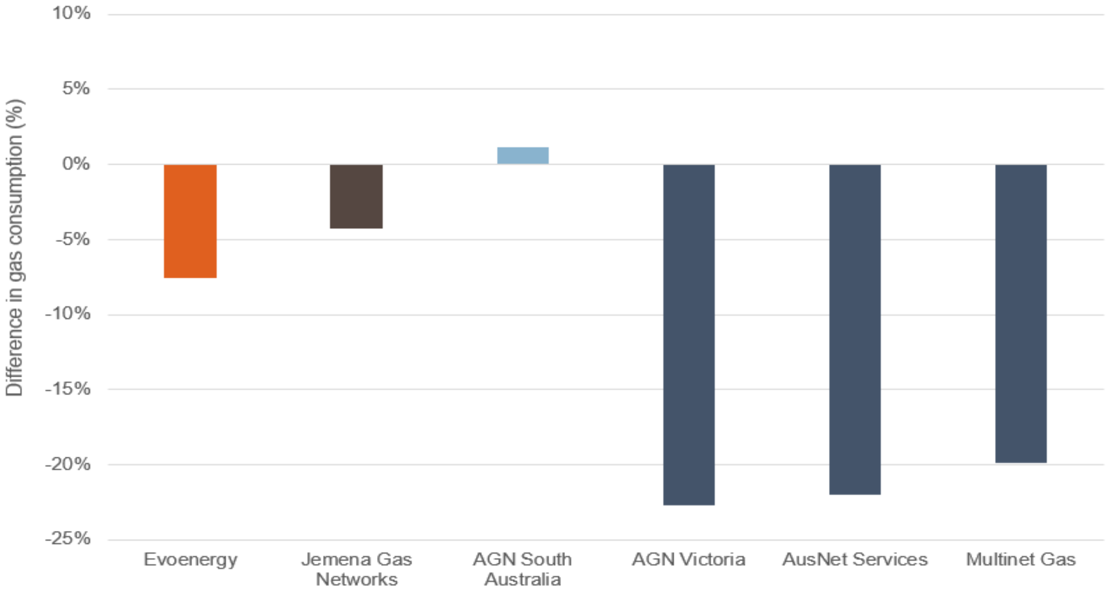


Source: Gas delivered: Annual RINs - N1.1 Demand by customer type.

This indicates that the decrease has been primarily caused by lower gas demand from residential customers, with a 16% reduction from last year.

Above we noted that due to their shorter regulatory year, we annualised the respective volumes for Victorian DNSPs. This involved annualising gas consumption volumes from January to June 2023, which appears to have led to significant lower gas demand for Victorian DNSP's residential customers when compared to last year.

Figure 4-14 Total gas delivered - residential customers 2022 to 2023 - DNSPs



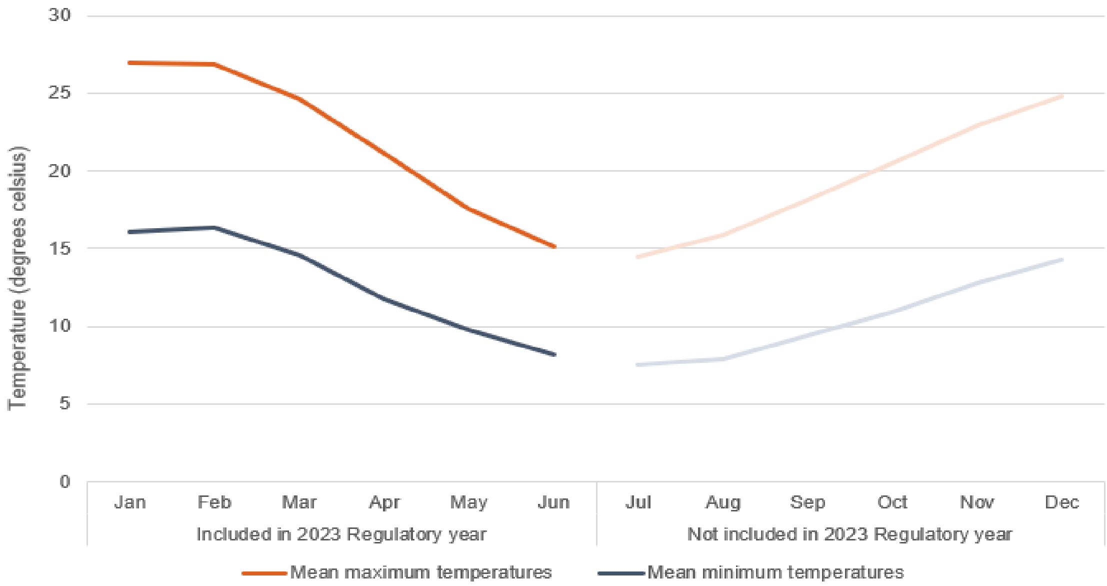
Source: Gas delivered: Annual RINs - N1.1 Demand by customer type.
Note: Colour of each DNSP is based on the respective jurisdiction in which the gas DSNP operates. Evoenergy (orange) - ACT, Jemena Gas Networks (brown) - NSW, AGN South Australia (light blue) - South Australia and AGN Victoria, AusNet Services and Multinet Gas (navy blue) - Victoria.
Difference in consumption determined by percentage change in DNSP's residential consumption from prior year.

This lower demand is primarily due to customers having a reduced propensity for gas usage in January to June annualised period. Gas usage for residential customers is mostly used for space heating during winter, as evident in Energy Network Australia's (ENA) 2021 Reliable and clean gas for Australian homes report. This report stated that demand for gas in winter for south-eastern Australia is more than triple the demand in summer, with cooler weather driving gas demand for residential customers.

In Figure 4-15 we have provided mean minimum and maximum temperature data from the Bureau of Meteorology (BOM) from Melbourne,[96] from the period 1991 to 2020, and highlighted the months included in the 2023 regulatory year.

[96] Data from the Melbourne Regional Office.

Figure 4-15 Melbourne mean, maximum and mean minimum temperature data



Source: BOM mean minimum and maximum temperature data from period 1991 to 2020.

This indicates that the mean minimum temperature is:

- lowest in the calendar year in July and August
- lower in September than May
- lower in October than April

On this basis, the low residential gas demand for 2023 in Victoria may not be reflective of the "true" gas demand, as the months in their 2023 regulatory year are not reflective of a typical 12-month regulatory year. Due to this, any conclusions that 2023 gas demand data is indicating falling residential demand are not accurate.

In relation to future gas demand, the effect of policy developments toward net-zero on the future use of gas networks and gas demand is uncertain. In assessing external views, AEMO's 2023 Gas statement of opportunities (GSOO)'s orchestrated step change scenario forecasts a decline in residential and commercial consumption by 66% from 2022 to 2042.[97] AEMO provides that the primary drivers of the forecast are new buildings transitioning to electric-only connections and existing customers switching from gas to electricity for their heating, hot water and cooking.[98]

In future years we will continue to monitor gas demand and customer numbers to provide context to stakeholders on how the use of the gas distribution networks is evolving.

4.3.3 UAFG remains an issue for gas distribution networks

Unaccounted for gas (UAFG) is the difference between the measured quantity of gas entering the network (gas receipts) and measured gas deliveries (gas withdrawals). UAFG

[97] The 66% decrease in the orchestrated step change involves a decrease from 194 PJ to 75 PJ over the 2022 to 2024 period.

[98] AEMO, Gas statement of opportunities, March 2023, p. 33.

can have various causes, however they can be broadly itemised into 5 categories: gas leakage (fugitive emissions), metering errors, gas heating values (losses related to the quality of gas injected into the pipelines), data quality, and theft.[99]

UAFG is an important measure for customers both financially and for the environment:

- UAFG is included as allowed opex for AGN South Australia, Evoenergy and Jemena Gas Networks, as these DNSPs directly contract UAFG volumes. Pursuant to the base step trend opex framework, if UAFG is higher than forecast, it will increase the allowed opex in the subsequent access arrangement and prices for customers. Conversely, if UAFG is lower than forecast, it will reduce the allowed opex and enable lower costs for customers
- For Victorian DNSPs the ESC sets a benchmark rate of UAFG for each Victorian DNSP. Where actual UAFG is lower than the benchmark rate, retailers who contract for their customer load, will be required to make reconciliation payments to these DNSPs. Conversely if actual UAFG is above the benchmark, these DNSPs will need to compensate retailers, incurring expense which lowers their profitability
- For the environment, UAFG leaked into the atmosphere has a significant negative impact. According to the United States Environmental Protection Agency, methane (the largest component of natural gas) is more than 28 times[100] as potent as carbon dioxide at trapping heat in the atmosphere

Our previous analysis on UAFG noted the control that the DNSPs had over UAFG was uncertain. Although there was a decrease in AGN South Australia's UAFG as they undertook mains replacement, there was no general relationship evident. Historically, the UAFG for DNSPs has remained relatively stable, varying from 3.2% to 3.4% of delivered gas volumes.

In 2023, the UAFG loss rate has increased from 3.4% to 3.9%, with the Victorian DNSPs having a higher loss rate than last year.

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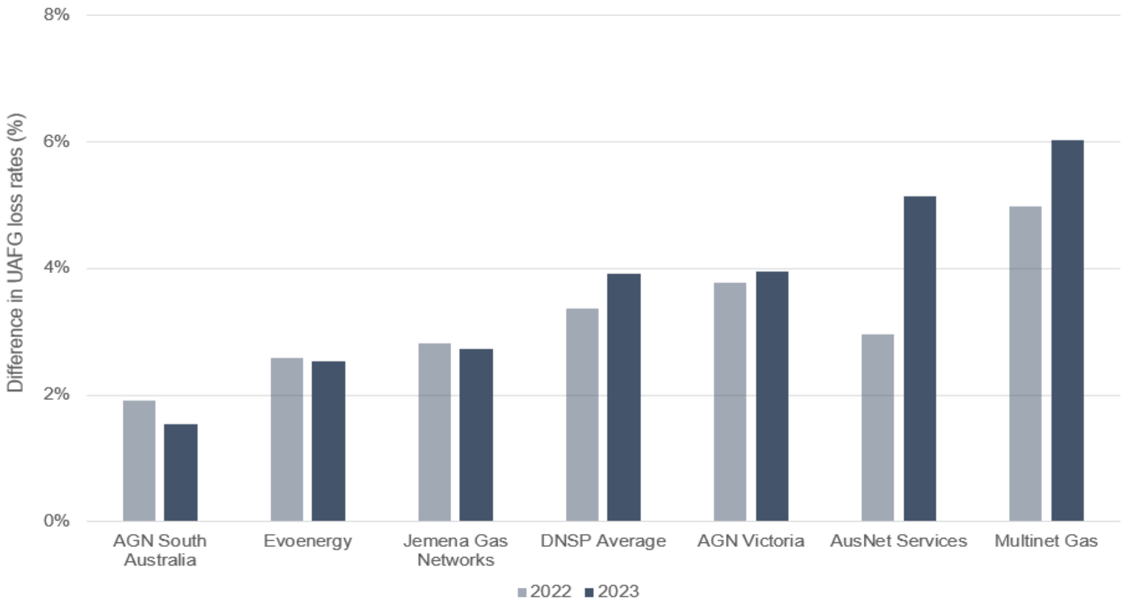
99 ESC observed up to 17 different components within these 5 categories in Review of unaccounted for gas benchmarks: final decision, December 2022, p. 7.

100 United States Environmental Protection Agency, Importance of methane, November 2023, accessed 14 March 2023.

Figure 4-16 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.

As noted above, there should be a high degree of trepidation around conclusions drawn from the annualised numbers for Victorian DNSPs. In Multinet Gas's submission[101] to the ESC for the UAFG Benchmarks from 2023 to 2027 they raised the issue that warmer temperatures which vary from base conditions (15 degrees Celsius and standard atmospheric conditions of 101,325 absolute pressure) result in inaccuracies with the measured energy and UAFG.[102] This analysis also noted that the effect of lower consumption by residential customers and higher gas temperatures in warmer months has an adverse effect on UAFG.[103]

This may indicate that the warmer months being overrepresented in the six-month 2023 regulatory year is resulting in a UAFG loss rate which isn't representative of the DNSPs "true" UAFG loss rate. These numbers would need to compare against UAFG losses incurred in future years before any increases to UAFG loss rates could be confirmed.

4.3.4 Pipeline outages remain infrequent for customers

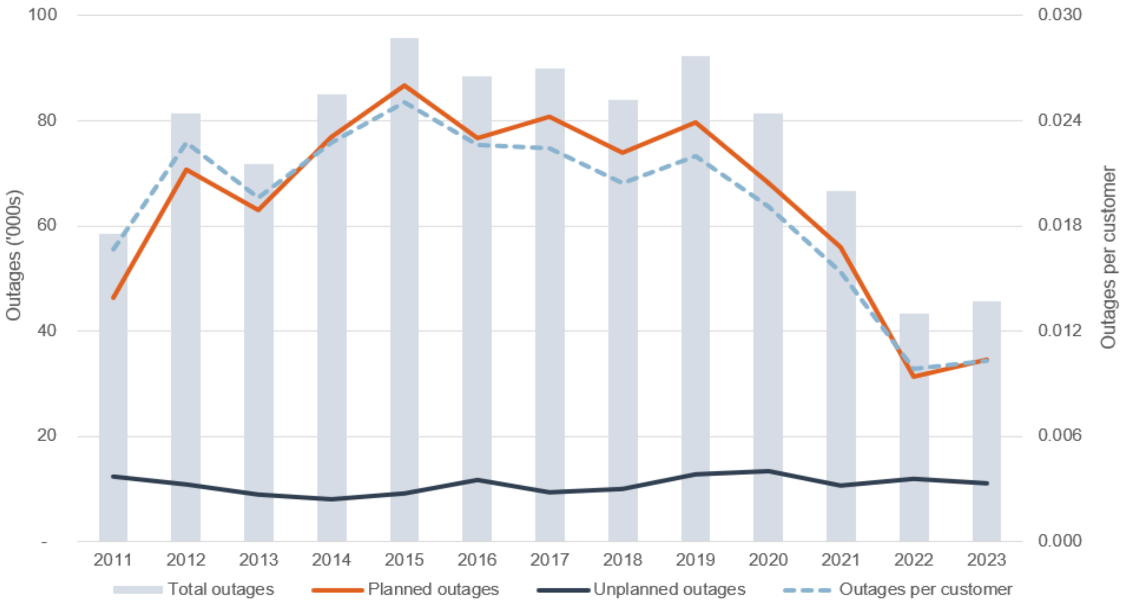
The NSP's network assets are inherently reliable. This is because:

- by being substantially underground the network assets are more protected from adverse weather conditions than electricity networks
- pipelines usually can carry out works without causing supply outages

Due to these factors, outages are infrequent, and although marginally increasing in 2023, there were less than 0.01 outages per customers on average.

101 Mulltinet Gas, Unaccounted for gas benchmarks 2023-27, September 2022.
102 Multinet Gas, Unaccounted for gas benchmarks 2023-27, September 2022, p 10.
103 Multinet Gas, Unaccounted for gas benchmarks 2023-27, September 2022, p 11.

Figure 4-17 DNSPs outages



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 2023 numbers, statistically 1 in 100 customers will experience an outage on a distribution network each year. Despite this, due to gas being a necessity for industry and commercial businesses and residential customers, a single outage can have a significant detrimental impact. Due to this impact, 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. Due to this, although the data is beneficial in monitoring the outages trend for a gas distribution over a period of time, it is limited in comparing the relative outage performance for each DNSP.

5 Financial performance in 2023

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 Appendix C, Appendix D and Appendix 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 and EBIT per customer profitability measures included in this report are exclusive of inflation, i.e. a 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 a NSP inclusive or exclusive of the indexation of the RAB/CAB.[104]

In previous years we also reported on a fourth profitability measure - RAB Multiples, which is calculated as the NSP's enterprise value divided by its RAB or CAB. In 2022, SKI and AST were delisted from the ASX with RAB multiples of 1.27 and 1.42 respectively. Following these transactions, there are no relevant trading multiples in relation to electricity or gas NSPs and no update to our previous year's report's analysis.

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 regulatory incentives.

The incentive-based regulatory framework is based on outperformance by NSPs and therefore an NSPs actual performance will differ from the forecasts and benchmarks we set. These can occur through a number of reasons, some of which are detailed in Table 5-1.

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

Table 5-1 Drivers of differences between actual and forecast returns for NSPs

Reason	Relevant profitability measures	Explanation
Revenue differences	RoRE RoA EBIT per customer	There are several reasons for revenue differences, which can lead to differences between actual and allowed returns. For electricity NSPs this can be due to electricity NSPs 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 and the revenue from cost pass throughs during the regulatory period. For gas NSPs, in addition to revenue smoothing and cost pass throughs, revenue differences occur under the weighted average price cap.[105] Although this exposes the gas NSPs to demand or volume risk, they can earn additional revenues and generate higher returns if the gas NSP outperforms respective demand forecasts included in their access arrangements.
Pass through revenues	RoRE RoA EBIT per customer	Electricity DNSPs also recover other pass-through revenues, including revenue earned on behalf of transmission NSPs and revenue related to jurisdictional schemes. An electricity DNSP may under or over recover revenues for these pass throughs each year, resulting in its returns deviating from allowances. An electricity DNSP must operate an 'unders and overs' account for both transmission and jurisdictional scheme revenues. This allows the electricity DNSP to recover its allowed revenue in net present value terms over time.
Opex Outperformance	RoRE RoA EBIT per customer	The difference between the NSP's actual opex incurred and the opex allowance included in the NSPs regulatory determination or access arrangement. Opex below the allowance will result in higher returns, whilst opex above the forecast will result in lower returns. Under our incentive based regulatory framework, any opex outperformance will also reduce the opex allowances included in subsequent regulatory determinations or access arrangements.
Capex Outperformance	RoRE RoA EBIT per customer	The difference between the actual capex and the capex forecasts in an NSPs regulatory determination and access arrangements. If an NSP is more efficient with capex or underspends on its capex allowance, it will result in a higher return. Similarly, any overspends will decrease the returns to the NSPs.
Incentive schemes	RoRE RoA EBIT per customer	The revenues earned or payments incurred by the NSP from their performance on incentive schemes. These incentive schemes are designed to incentivise NSPs to improve outcomes for customers by achieving lower costs, higher reliability, and other desirable outcomes.
Capital structure	RoRE	When the debt in the capital structure of the NSP or the corporate group in which it is a subsidiary is greater or less than the assumed regulatory benchmark gearing ratio. This does not involve customers paying more for their network services, but rather the NSPs choosing to take on higher or lower risk (by holding

105 Refer to section 3.1.5 of the 2023 Gas network performance report for a wider discussion on how gas NSPs can outperform demand forecasts and achieve higher revenues.

Reason	Relevant profitability measures	Explanation
		a different proportion of debt) to achieve higher or lower returns for themselves
Cost of debt	RoRE	The difference between the NSPs actual interest rate or yield on debt and the prescribed cost of debt in the NSP's regulatory determination or access arrangement. Although the NSP can achieve greater returns if they outperform the cost of debt by raising debt at a lower cost, they will also bear any costs which are above the prescribed cost of debt.
Inflation rate variation	RoRE[106] RoA (nominal only) EBIT per customer (nominal only)	The difference between the actual rate of inflation for the year and the inflation forecast in the NSPs regulatory determination or access arrangement. Under our regulatory framework NSPs bear the risk on variation from forecast inflation. An NSP's expected inflation for a regulatory period is determined during the regulatory process. Due to this if inflation is higher than forecast, it will drive higher returns for the NSPs, whilst lower inflation will drive lower returns.

Source: AER analysis

5.1 Networks RoA performance

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.

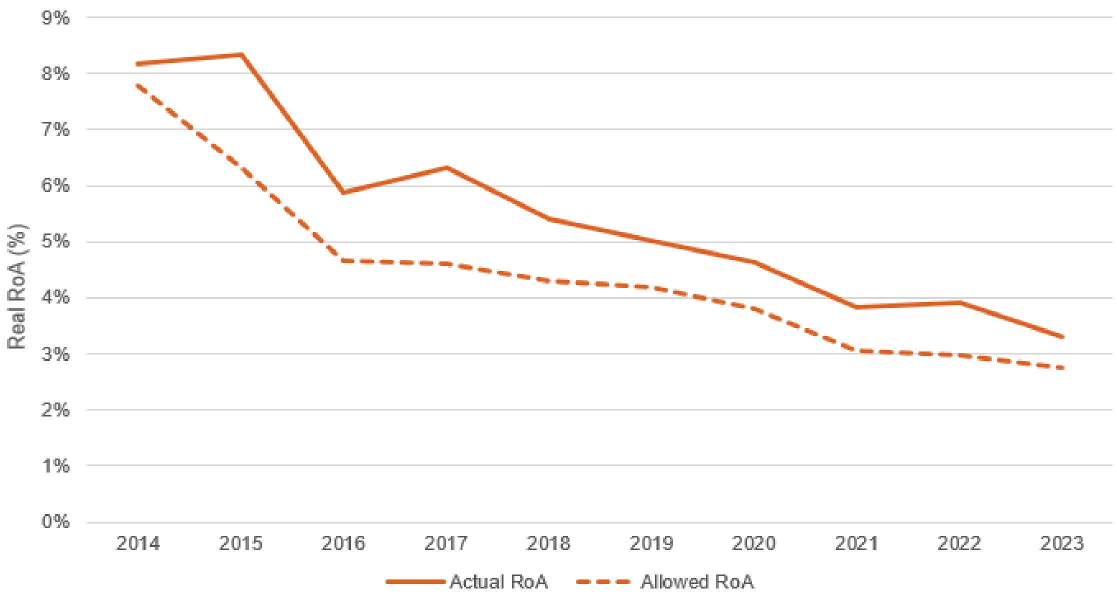
The RoA profitability measure is the best assessment on whether NSPs have outperformed their allowed rate of returns and achieved the NEO or NGO. This is due to outperformance from capex, opex and incentive schemes being key features of our incentive based regulatory framework, where the outperformance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

5.1.1 Electricity network's RoA outperformance narrowing

In 2023, NSPs on average have continued to generate real RoA which exceed forecast (allowed) returns despite declining forecast returns.

106 Refer to the 2023 Electricity network performance report and 2023 Gas network performance report for a detailed explanation as to why indexation affects real returns on equity.

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



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

The contributions to the change in outperformance by the electricity NSPs on average have been driven by opex (0.2 percentage points), capex (0.1 percentage points) and incentive schemes (0.5 percentage points), which has been partially offset by the lower returns attributable to revenue differences across NSPs (0.4 percentage points).

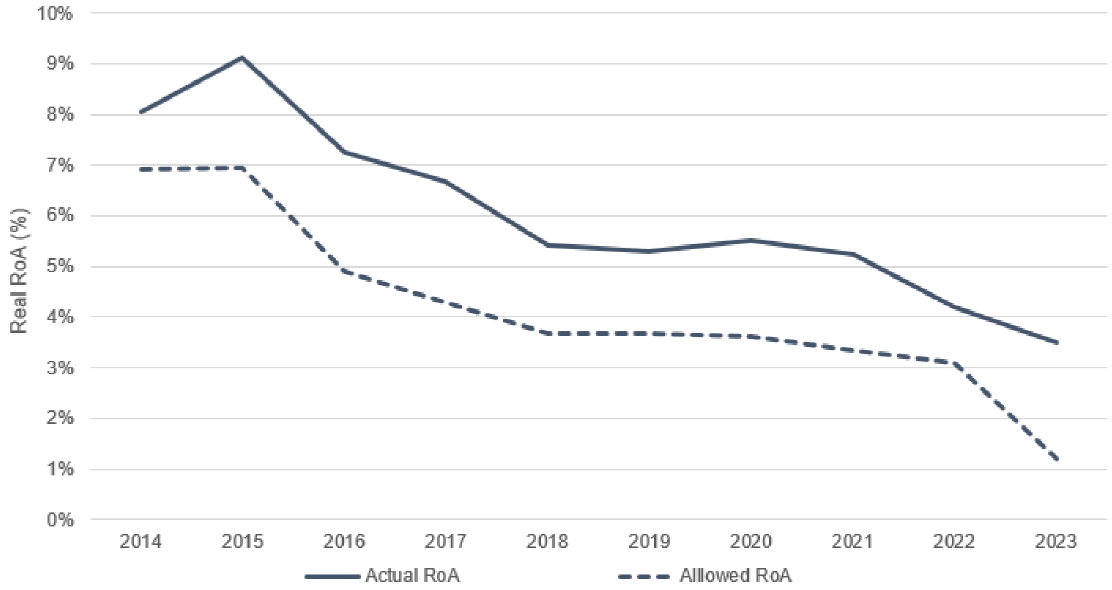
5.1.2 Gas distribution network's RoA outperformance appears to be widening

The results for outperformance of the gas DNSPs need to be treated with caution, until we have a full year dataset and the revenue recovery impacts of the transition have been normalised.

Based on the 6-month annualised data set, gas DNSPs on average have generated real RoA which exceed forecast (allowed) returns. The widening outperformance in 2023 has occurred with forecast returns declining more steeply than apparent actual real returns.[107]

107 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.

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



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

The outperformance by the gas DNSPs has been predominately driven by use of 2023 tariff prices in real terms for Victorian gas DNSP's six-month transitional access arrangement and other revenue adjustments (2.1 percentage points)[108] and opex outperformance (0.7 percentage points).

5.2 EBIT per customer decreases in 2023

EBIT per customer is a measure of an NSP's operating profit divided by its customer base.[109] 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.

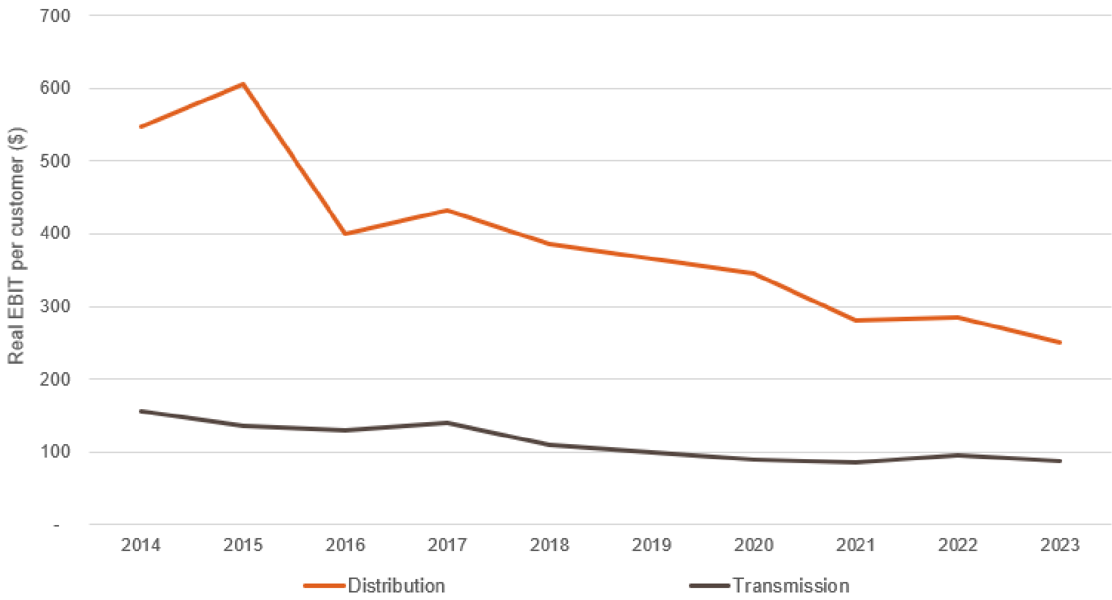
5.2.1 EBIT per customer decreases marginally for electricity networks

The electricity NSP's EBIT per customer decreased in 2023. This follows the same trend as the RoA, with lower EBITs for electricity NSPs and growing customer bases resulting in lower EBIT per customer.

108 The revenue adjustment for the six-month transitional access arrangement period is discussed in section 4.2.1.1 above.

109 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



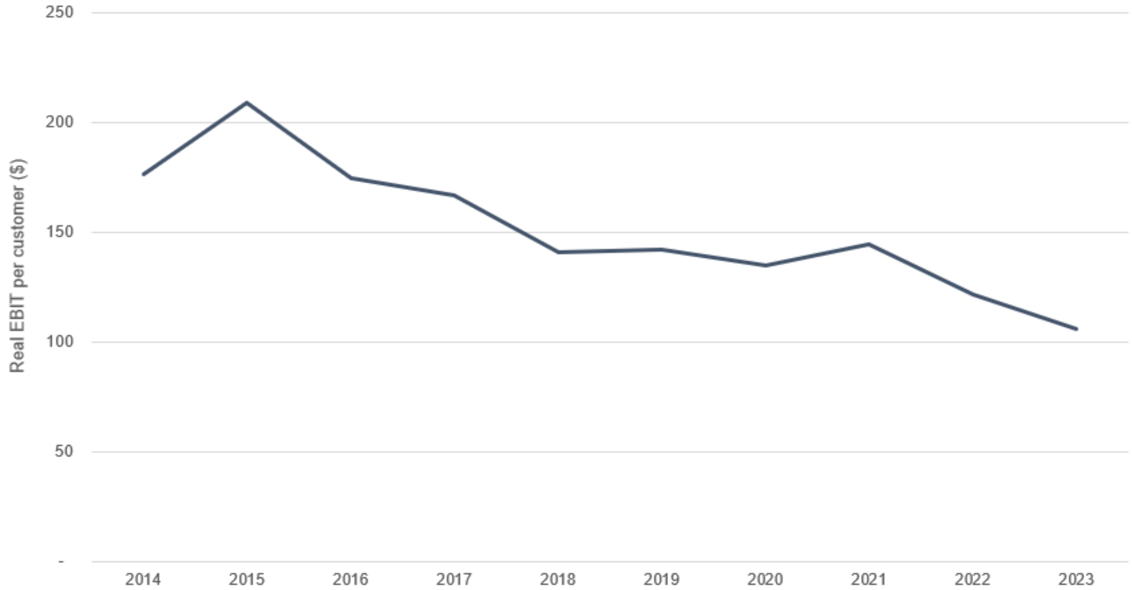
Source: Electricity financial performance model.
Note: Financial performance numbers are nominal. Calculation details are in the financial performance model and EBIT per customer explanatory note. The weighted averages are weighted by the customer base of the electricity NSPs.

The EBIT per customers for electricity TNSPs are materially lower than for electricity DNSPs. This is a consequence of the higher capital intensiveness of distribution networks compared to transmission networks, resulting in DNSPs having larger RABs per customer. However, as seen in our discussion of other profitability measures, it does not mean than electricity TNSPs are less profitable than electricity DNSPs in relation to same levels of investment.

5.2.2 EBIT per customer decreases slightly for gas distribution networks

The EBIT per customer for gas DNSPs has decreased in 2023, following the same trend over time as seen in their RoA.

Figure 5-4 Real EBIT per customer - gas DNSPs



Source: Gas DNSP financial performance model.
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 gas DNSPs.

5.3 RoRE outperformance impacted by inflation

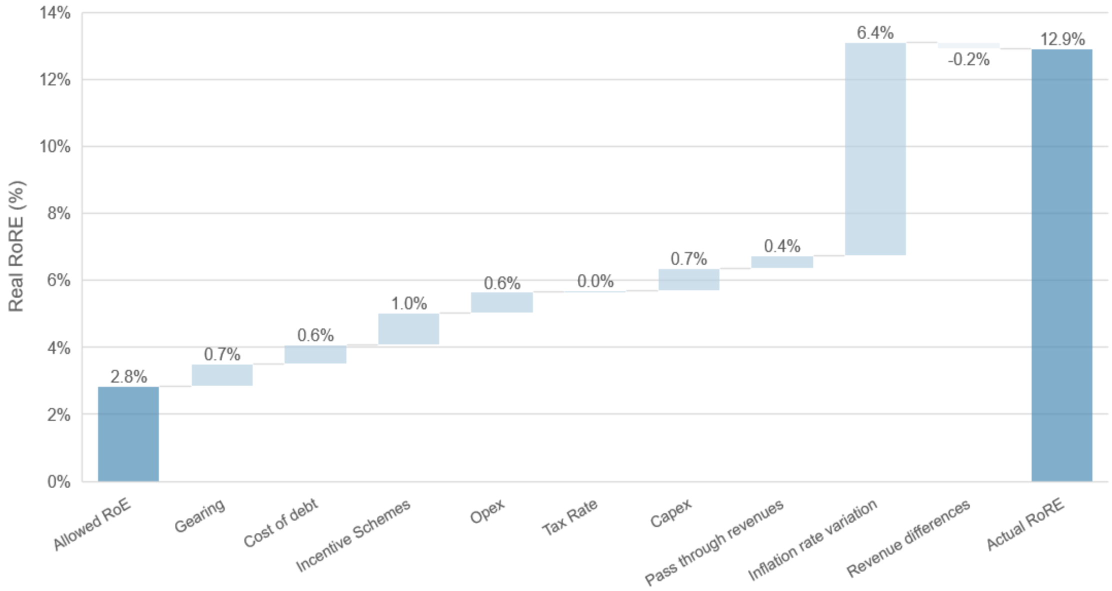
The RoRE is the net profit after tax (NPAT) divided by the NSP's regulated equity. As NPAT is the final or ultimate return to an NSP's equity holders, it captures the returns arising from differences between an NSP's:

- 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, as changes to tax policy, as well interest and inflation rates can result in NSP's under or outperforming their return on equity allowance.

In 2023, for most NSPs, the inflation applied under our regulatory framework was 7.8%, an increase from the forecast inflation of 2.3%. This had led to considerable outperformance for electricity NSPs and gas DNSPs on a combined weighted average basis, contributing 6.4 percentage points to the RoRE for electricity NSPs and gas DNSPs combined.

Figure 5-5 Detailed contributions to real RoRE - electricity NSPs and gas DNSPs - 2023



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 actuals for each driver being substituted for 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 in every year of the time series and take a weighted average across all electricity NSPs and gas DNSPs.

5.3.1 How does inflation impact the RoRE?

We calculate the RoRE in a method which is bespoke to our and similar regulatory frameworks. Due to this, there is limited comparability against other returns on equity in broader competitive markets. This is based on the treatment of an NSPs regulated revenue and expenses in the building block revenue framework and in our models—for example, valuing network assets using the RAB rather than their historical cost or fair value.

This calculation methodology is necessary to compare the outturn RoRE against the allowed returns on equity included in our regulatory determinations and access arrangement.

Under our regulatory framework we target a real rate of return, with expected inflation used to convert nominal allowed returns into real allowed returns. This estimate of expected inflation represents investors' expected value of actual inflation over the regulatory period, as is informed by forecasts of inflation by sources like the RBA. Under our regulatory framework, providing the estimated inflation expectations used to set the allowed returns were accurate at the time the real rate of return was determined, there will be correct compensation of allowed returns for NSPs, regardless of actual inflation outcomes.

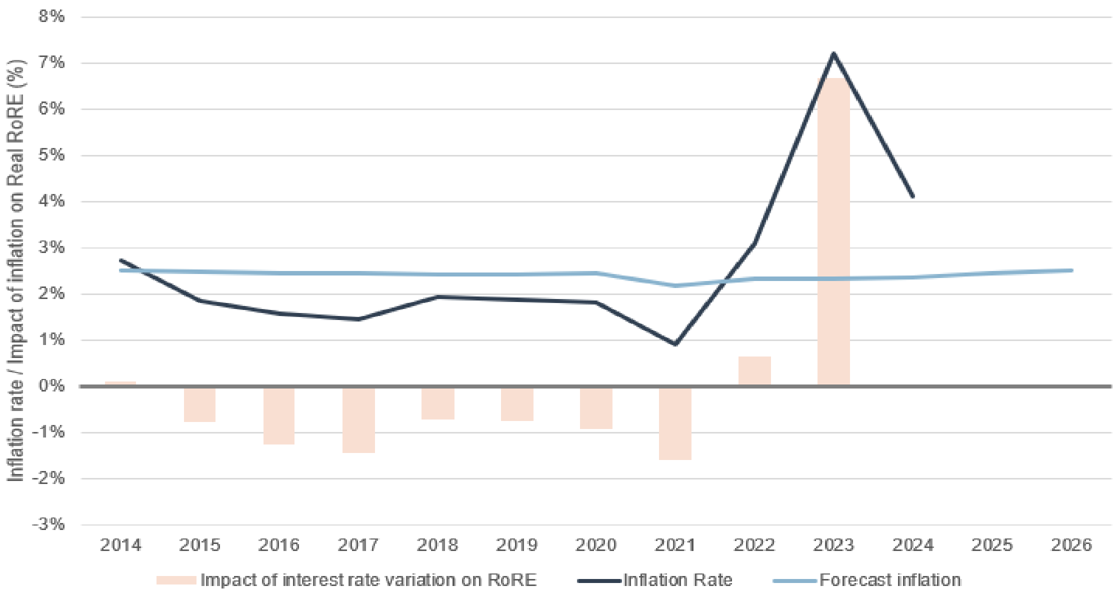
Our regulatory framework involves NSPs bearing the risk from actual inflation differing from expected inflation, as it is a more efficient allocation of risk. NSPs have greater resources or ability than consumers to mitigate against variations from expected inflation. One such example is the possible use of financial instruments to hedge against any changes to debt costs from inflation, although the use of such instruments would involve the NSPs incurring upfront transactional and other costs, which may not be included in an NSP's debt raising costs allowance.

As NSPs bear the risk from inflation, there will be overperformance for NSPs when inflation is higher than forecast, and underperformance when inflation is lower than forecast.

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 forecasts and the effect this had on real RoRE since 2014.

In the previous year, our electricity and gas reports noted that the significant inflation from the 2022 calendar year would impact our regulatory framework, as actual inflation is applied to index each NSPs RAB. In 2023, this indexation has driven a widening of the outperformance by NSPs against the allowed returns determined in their respective regulatory determination and access arrangements.

Figure 5-6 Inflation impact on real RoRE compared with actual and forecast inflation - electricity NSPs



Source: Electricity financial performance model and Reserve Bank of Australia's (RBA) February 2024 Statement of monetary policy.

Differences between the forecast and actual inflation applied to index RABs impacts an NSP's RoRE. When inflation is below levels forecasted by the AER, as occurred between 2015 and 2021, lower indexation of interest-bearing liabilities has had a negative impact on RoRE.

Conversely, when actual inflation is higher than forecasted, as occurred in 2022 and 2023, it has had a positive impact on RoRE. These effects are amplified in networks that are financed with a higher proportion of interest-bearing liabilities than our benchmark gearing level of 60%.

It is worth noting that the average indexation applied to most NSPs' RABs and CABs in 2022 and 2023 is on a lagged basis and differs from the actual CPI for that regulatory year. The majority of NSPs apply inflation to their RAB and CAB on a 6-month lagged basis, whilst Victorian electricity and gas DNSPs apply their inflation on an 18-month lagged basis.

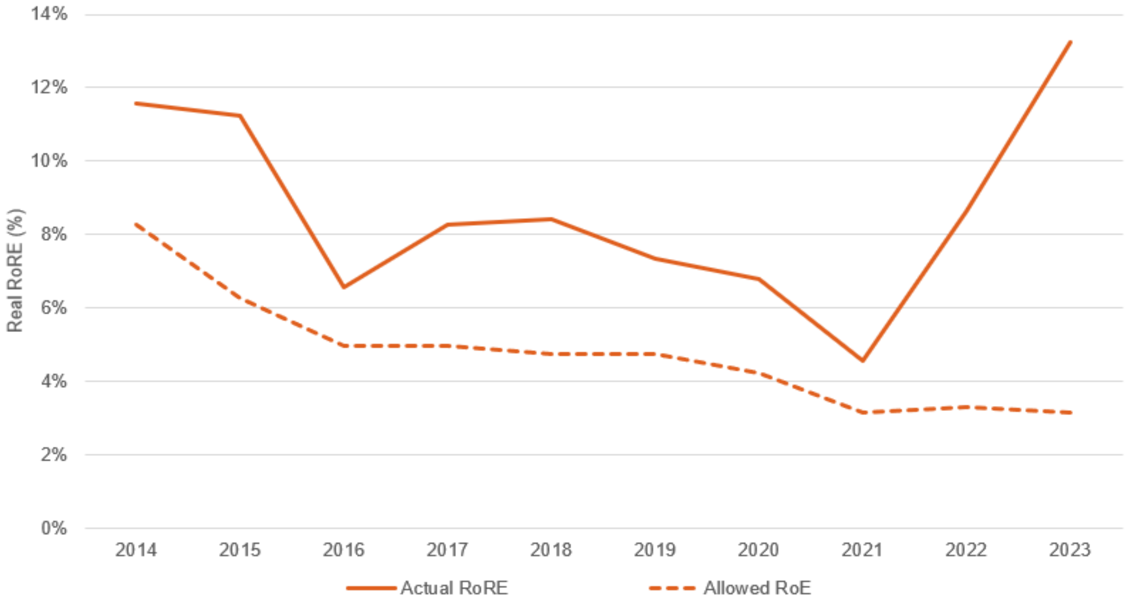
The inflation rate variation occurs in our regulatory framework when actual inflation differs from expected inflation. Due to this, the gradual lowering of actual and forecast inflation will be reflected in upcoming regulatory determinations and access arrangements, resulting in an increase in forecast inflation for their regulatory periods.

As an outcome of our 2020 inflation review,[110] we changed our inflation term from 10 years to 5 years. This allows our forecast inflation rate for our upcoming regulatory determinations and access arrangements to be more responsive to changes in market circumstances and decrease the magnitude of any inflation rate variation in the RoRE.

5.3.2 Inflation drives electricity network's RoRE outperformance

In 2023, the weighted average electricity NSP RoRE increased by more than 4 percentage points over the previous year and has increased by almost 9 percentage points since 2021, when inflation began to rise.

Figure 5-7 Real RoRE[111] versus allowed RoE - electricity NSP



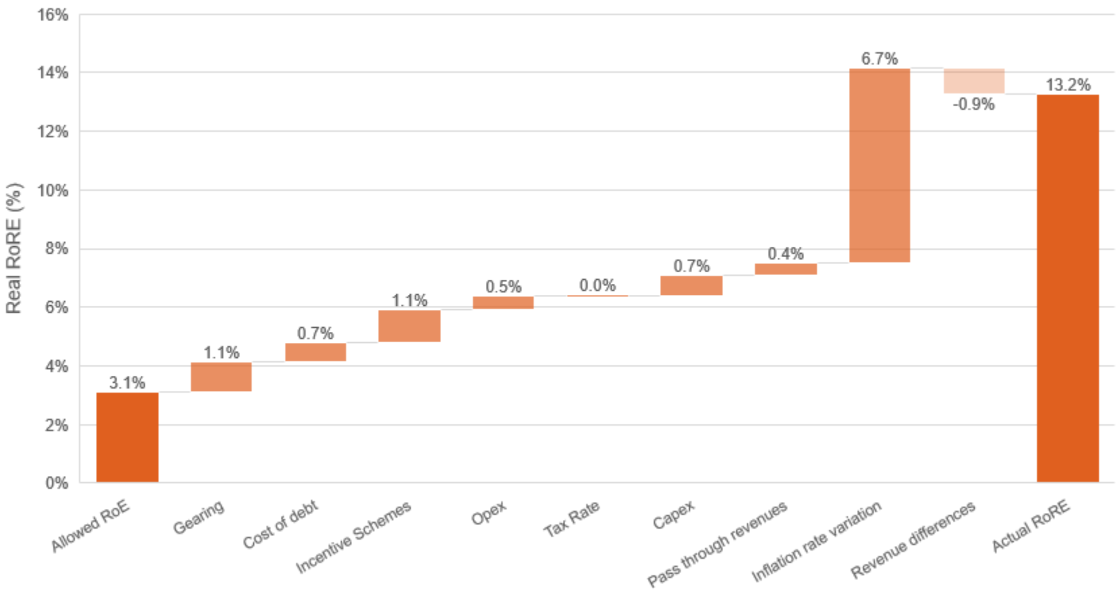
Source: Electricity financial performance model
Note: Financial performance numbers are nominal. The weighted average RoRE is calculated by multiplying an electricity NSP's real RoRE against the proportional size of the electricity NSP's regulated equity.

The outperformance in 2023 has been largely due to the increase in returns from higher inflation than forecast (6.7 percentage points). However, electricity NSPs have also been able to achieve greater returns from their different gearing in their capital structures (1.1 percentage points), outperformance on the cost of debt (0.7 percentage points) and revenues from incentive schemes (1.1 percentage points).

110 AER, Final position - Regulatory treatment of inflation, December 2020.

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

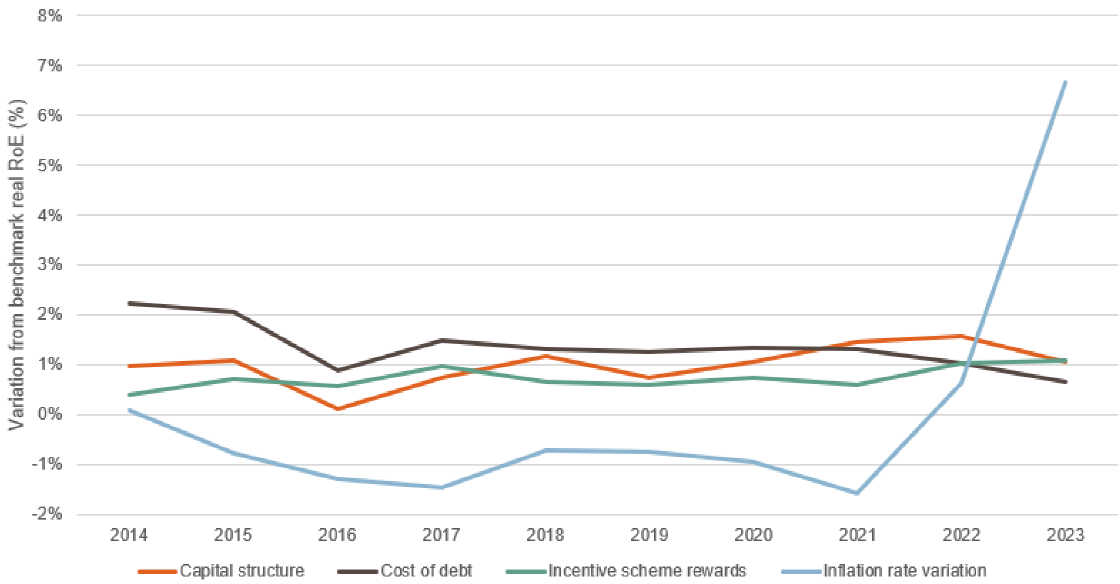
Figure 5-8 Detailed contributions to real RoRE - electricity NSPs - 2023



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

Since 2014, on average electricity NSPs have consistently achieved outperformance on their return on equity from their capital structures, cost of debt and revenues from incentive schemes. This differs from the inflation rate variation, where the significant increase in 2023 contrasts starkly to the negative impact that the low inflation from 2015 to 2021 had on electricity NSP's average return on equity.

Figure 5-9 Contributions to real RoRE - electricity NSPs - capital structure, cost of debt, incentive schemes, and inflation rate variation



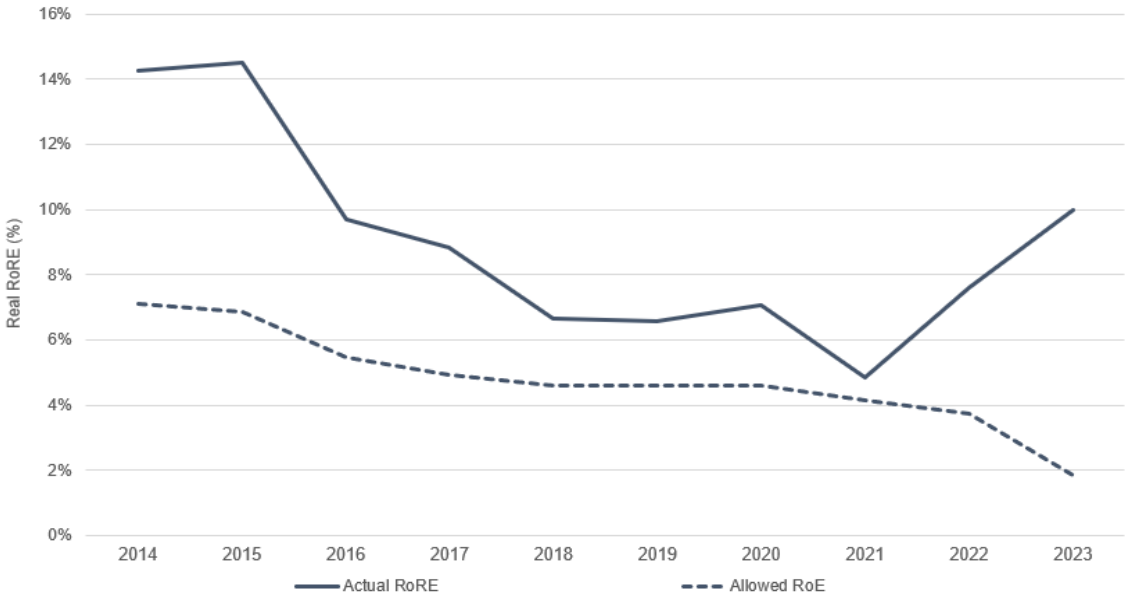
Source: PTRM and electricity financial performance model (confidential version).
Note: Refer to notes for Figure 5-5.

With annual inflation in the December 2023 quarter decreasing to 4.1%[112] from the December 2022 quarter annual inflation of 7.8%,[113] it is probable that there is a decrease in the inflation rate variation in the RoRE next year. However, this will be offset by the Victorian electricity DNSPs applying their 7.8% inflation on an 18-month lag to calculate their 2024 RoRE.

5.3.3 Gas distribution network's RoRE outperformance is apparently widening

In 2023 gas DNSPs on average achieved a RoRE higher than forecast. However as higher inflation had a lesser impact for gas DNSPs due to 18-month lag on inflation being applied to Victoria gas DNSPs' CAB, the outperformance is less than reported for electricity NSPs.

Figure 5-10 Real RoRE[114] versus allowed RoE - gas DNSPs



Source: Gas DNSP financial performance model.
Note: Financial performance numbers are nominal. The weighted average RoRE is calculated by multiplying a gas DNSP's real RoRE against the proportional size of the gas DNSP's regulated equity. The actual and allowed RoRE for Victorian gas DNSPs has been annualised.

The outperformance increased by over 4 percentage points from 2022. A portion of this widening in outperformance reflected forecast or allowed RoRE falling to a greater extent than actual RoRE on average for gas DNSPs.

The main driver of the outperformance from allowed returns is the inflation rate variation (3.5 percentage points). This is followed by the impact of the revenue adjustment for the Victorian

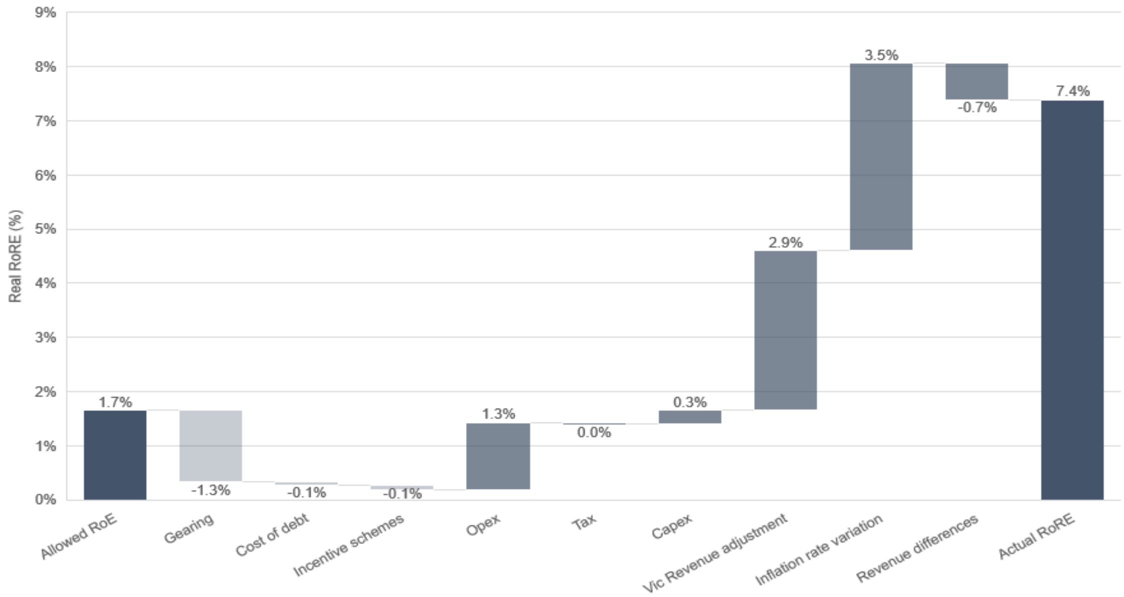
112 Australia Bureau of Statistics (ABS), Consumer price index (CPI) - December quarter 2023, January 2024, accessed 11 March 2024.

113 ABS, CPI - December quarter 2022, January 2023, accessed 11 March 2024.

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

gas DNSPs for their six-month transitional access arrangement (2.9 percentage points)[115] and the cumulative impact of opex outperformance by the gas DNSPs (1.3 percentage points).

Figure 5-11 Detailed contributions to real RoRE - gas DNSPs - 2023



Source: PTRM and gas DNSP financial performance model (confidential version).
Note: Refer to notes for Figure 5-5
The allowed real RoE provided in Figure 5-11 does not equal the weighted average RoRE provided in Figure 5-10. This is due to Figure 5-10 having annualised weighted average allowed RoE and RoRE for Victorians gas DNSPs, whilst Figure 5-11 uses the financial performance of the Victorian gas DNSPs for their six-month period. This is to provide a more accurate representation of contributions to real RoRE for gas DNSPs for the regulatory period.

Since 2014, the drivers of outperformance for gas DNSPs have differed from electricity NSPs. Due to lower rewards and penalties from incentive schemes, there has been no RoRE impact from incentive schemes. Outperformance is also attributable to revenue growth, which can occur through demand outperformance under a weighted average price cap.

In particular, the revenue growth for JGN over the 2015 to 2020 period created significant RoRE outperformance. This growth was due to several factors including demand outperformance, tariff variations and the limited merits review process and application of interim enforceable undertakings to set how JGN’s revenues and tariffs were determined.[116]

In contrast to electricity NSPs there has been under performance for gas DNSPs from cost of debt and the capital structures (gearing) leading to lower rate of returns since 2015. This highlights how the historical gearing of NSPs are not consistent across the energy sector, with differing ownerships having different corporate structures or assessments of required levels of debt.

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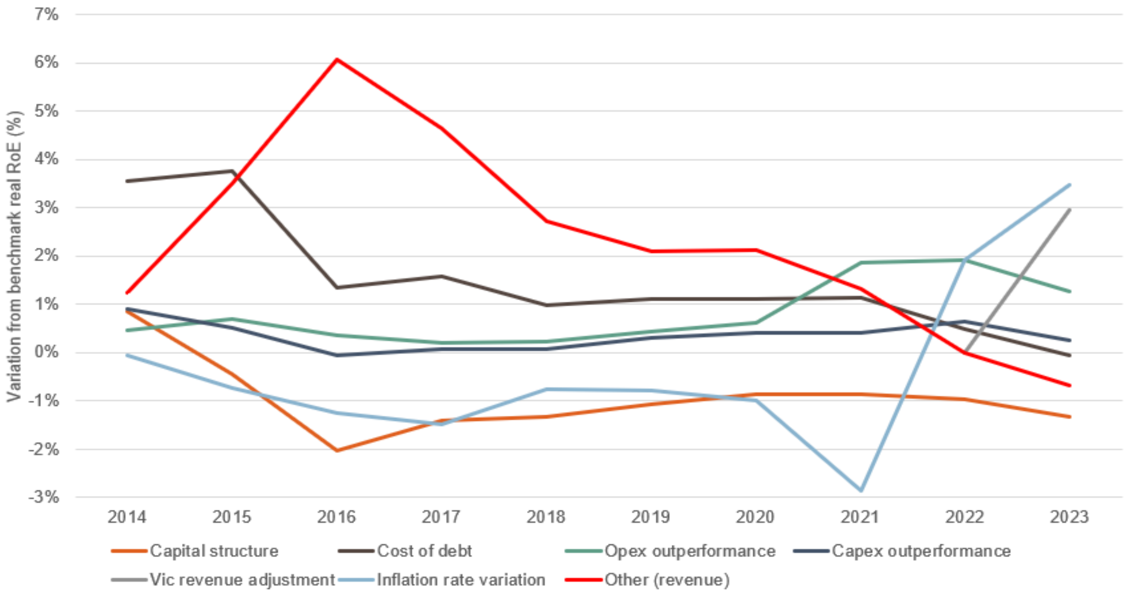
115 The revenue adjustment for the six-month transitional access arrangement period is discussed in section 4.2.1.1 above.

116 Refer to our 2021 Gas network performance report for further discussion.

Figure 5-12 Contributions to real RoRE - gas DNSPs



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

The 18-month lag on inflation also applies to the three Victorian gas DNSPs: AGN Victoria, AusNet Services and Multinet Gas. This has contributed to a lower inflation rate variation (3.5 percentage points compared to 6.7 for electricity NSPs). Due to this, we expect similar real RoRE outcomes next year if the gas DNSPs were to achieve similar outperformance on the other drivers.

5.3.4 Impact of inflation on RoRE

Our analysis provided above, indicates that the RoRE measure has been significantly impacted by inflation. This is due to the NER requiring us to specify a method for indexing the RAB,[117] whilst the NGR allows the AER to prepare a capital base roll forward model with stakeholders,[118] with our published models including our preferred method for indexing the capital base.[119]

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

As provided above, we use expected inflation to convert nominal allowed returns into real allowed returns and index the RAB based on actual CPI data. To prevent NSPs from being double compensated for inflation, we apply a negative revenue adjustment (through depreciation) to ensure that the impact of inflation is not double counted.

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117 NER, r.6.3.2(2) & r.6A.4.2(4).

118 NGR, r.75A(1) & (2); r.72(3).

119 AER, Post-tax revenue model handbook - Gas distribution service providers, April 2020, p. 22; AER, Post tax revenue model handbook - Gas transmission service providers, April 2020, p. 22.

In our models, to ensure consistency with this approach and to reflect that the debt component of the return on capital is provided in nominal terms, we index the share of the RAB and CAB funded by the NSP's debt. This indexation and the returns from imputation credits are added to the NPAT to calculate the regulatory NPAT required to calculate the real RoRE.

5.3.4.1 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, this may not resemble profit to an NSP's equity holders which increases the equity in their business or the cash available for disbursement. This is due to several factors, including:

- 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.
- higher (or lower) inflation resulting in higher (or lower) 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 or lower returns due to inflation could be seen as similar to 'unrealised gains or losses' on assets as these returns will only be recovered in future regulatory periods or access arrangements. Due to this, any higher or (lower) RoRE performance from inflation in a respective year will not result in immediate higher or lower cash flows for NSPs or distributions to their equity holders.
- 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. Despite this, we believe the RoRE is a profitability measure which can provide insights to stakeholders on the ultimate returns provided to equity holders from the NSP's core regulated services.

We believe the greatest utility of the RoRE is to provide important information to stakeholders to comprehensively compare an NSP's actual returns against their expected returns and analyse what is having a positive and negative impact on their returns.

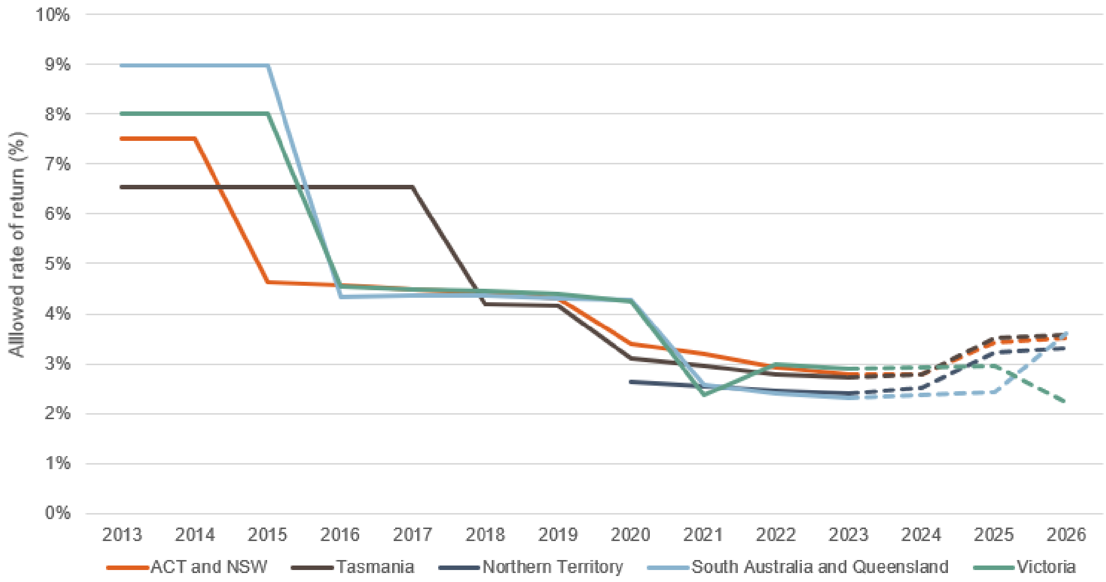
5.4 Outlook for future allowed returns

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.

The regulatory cycle commenced again in July 2024, when NSW, Tasmania, ACT and NT electricity DNSPs start their 2024-29 regulatory period, where new rates of return regulatory determinations will be made. In the following year, SA Power Networks, Energex, and Ergon Energy will also commence their forthcoming 2025-30 regulatory period.

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 remain constant across an NSP's regulatory period, whilst their return on debt is updated annually.

Figure 5-13 Allowed rate of return - electricity DNSPs

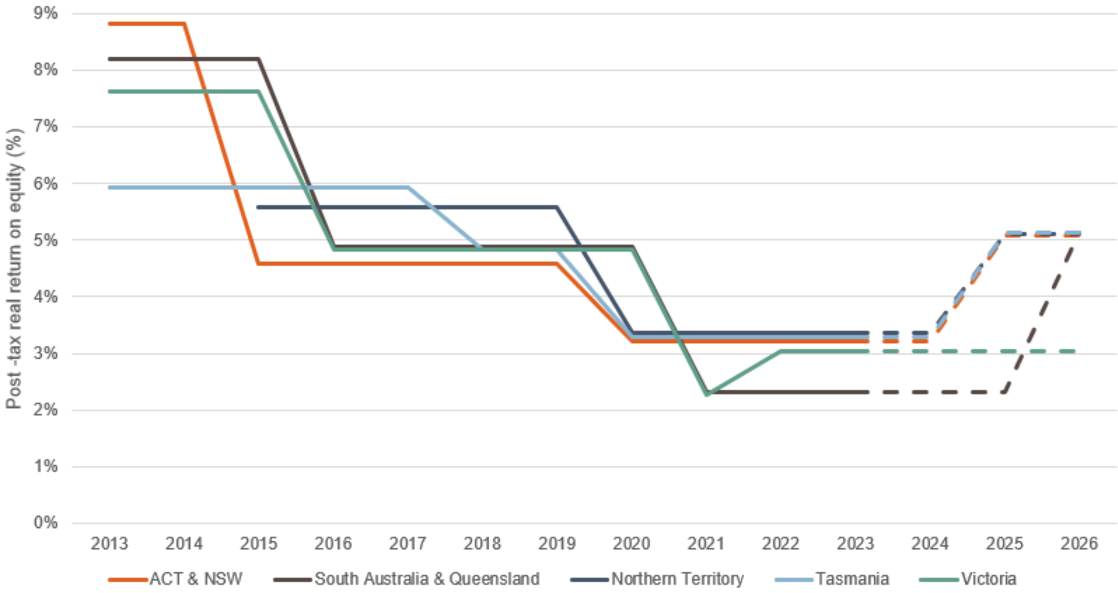


Source: Allowed real rate of return - PTRM 'WACC' sheet.

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, as the return of debt is progressively updated for any changes in an NSP's debt costs. For consumers, this means that recent increase in interest rates will be experienced immediately, but rather gradually implemented in their network costs using a trailing average approach across a 10-year period.

In contrast, as noted with the recent ACT, NSW, NT, and Tasmanian electricity DNSP regulatory determinations for the 2024-29 regulatory period, changes in the required return in the capital or financial markets for an investment of similar risk will be immediately reflected in an NSP's return on equity.

Figure 5-14 Post-tax real return on equity - electricity DNSPs



Source: Allowed real rate of return - PTRM ‘WACC’ sheet.

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 NSPs rate of return and an NSP’s forecast revenues from changes in the external environment between regulatory determinations.

On average the allowed rate of return will begin to increase in 2025 for ACT, NSW, NT, and Tasmanian electricity DNSPs, with a corresponding increase for SA Power Networks, Energex, and Ergon Energy in 2026, based on their regulatory proposals. Any increases in an NSP’s allowed returns will be reflected in an NSP’s forecast revenue through the return on capital building block.

6 Foreshadowing network revenue increases in 2024

Each year, we approve the network revenues that electricity and gas DNSPs propose to recover from their customers for the upcoming regulatory year. This involves:

- for electricity DNSPs a pricing proposal that contains the network tariffs they propose to charge to recover their distribution revenues, transmission network costs and costs of jurisdictional schemes
- for gas DNSPs a tariff variation notice which contains the tariffs they propose to charge to recover their distribution revenues

We do not approve prices on an annual basis for electricity TNSPs.

As all electricity and gas DNSPs now have a financial year regulatory year, the pricing proposals for a respective year are typically received and approved in March and May respectively before the start of the regulatory year. The approved tariffs are then charged throughout the regulatory year. For electricity DNSPs and gas DNSPs, this period is 1 July 2023 to 30 June 2024.

In this chapter we are providing information on the network revenues to be recovered from consumers in the 2024 regulatory year, to give stakeholders more contemporaneous information and to discuss how they differ from 2023.

6.1 Electricity network revenues to decrease in 2024

In the 2024 regulatory year there will be a 2% increase in distribution revenues in real terms or a 10% increase in nominal terms.

For network revenues, after including transmission and jurisdictional scheme revenues there is a 1% decrease in real terms and a 7% increase in nominal terms.

Table 6-1 Distribution and network target revenues for 2023 and 2024

Electricity DNSP	Distribution target revenue ($m 2023)		Variance (2023 to 2024)		Network target revenue ($m 2023)		Variance (2023 to 2024)	
	2023	2024	Real	Nominal	2023	2024	Real	Nominal
Total	9,903	10,109	2%	10%	13,315	13,175	(1%)	7%
Evoenergy	146	148	1%	9%	346	218	(37%)	(32%)
Ausgrid	1,431	1,466	2%	10%	1,979	1,972	0%	7%
Endeavour Energy	906	909	0%	8%	1,225	1,211	(1%)	7%
Essential Energy	1,075	1,077	0%	8%	1,423	1,388	(3%)	5%
Energex	1,263	1,295	3%	11%	1,698	1,652	(3%)	5%
Ergon Energy	1,277	1,250	(2%)	6%	1,607	1,572	(2%)	5%
SA Power Networks	834	854	2%	11%	1,241	1,288	4%	12%
TasNetworks	267	276	4%	12%	345	346	0%	8%
AusNet Services	749	793	6%	14%	900	932	4%	12%
CitiPower	324	339	4%	13%	438	442	1%	9%
Jemena	284	290	2%	10%	366	377	3%	11%
Powercor	741	774	4%	13%	977	991	1%	9%
United Energy	462	484	5%	13%	625	634	1%	9%
Power and Water	144	155	8%	16%	144	155	8%	16%

Source: Distribution target revenue: Electricity DNSP's approved pricing model - Allowed distribution revenue - Total approved revenue. Transmission target revenue: electricity DNSP's approved pricing model - Allowable DPPC revenue - Total approved revenue. Jurisdictional scheme target revenue: electricity DNSP's approved pricing model - Allowable JSA revenue - Total approved revenue.
Note: AER calculation to convert some numbers to $ June 2023 and nominal terms. Network revenue is the sum of distribution, transmission, and jurisdictional revenue.

The network revenue in Table 6-1 is not the sum of the target revenue for electricity DNSPs and electricity TNSPs.[120] Rather, it is sum of the distribution, transmission, and jurisdictional

[120] We use budgeted revenue from customers for electricity TNSPs.

scheme revenues of electricity DNSPs. The transmission and jurisdictional scheme revenues are pass through revenues, where the electricity DNSPs recover:

- for transmission revenues: the transmission costs which are paid to electricity TNSPs, the cross-boundary expenditure which are paid to other electricity DNSPs, and the avoided transmission expenditure paid for energy supplied to the electricity DNSPs for energy supplied by embedded generation. In 2023, in real terms, transmission revenues were approximately 23% of network revenues.
- for jurisdictional scheme revenues: the jurisdictional payments that an electricity DNSP is required to pay pursuant to its jurisdictional scheme obligations. These jurisdictional schemes differ amongst the electricity DNSPs, and on a total basis represent 5.5% of network revenues in 2023.

Consumers pay network revenues to their retailers when they pay their retail bill. Due to this, network revenues need to be used to determine the price impact on customers for electricity distribution and transmission networks.

6.2 Gas distribution target network revenues will increase in 2024

In the 2024 regulatory year there will be a 9% increase in distribution revenues in real terms and a 18% increase in nominal terms.

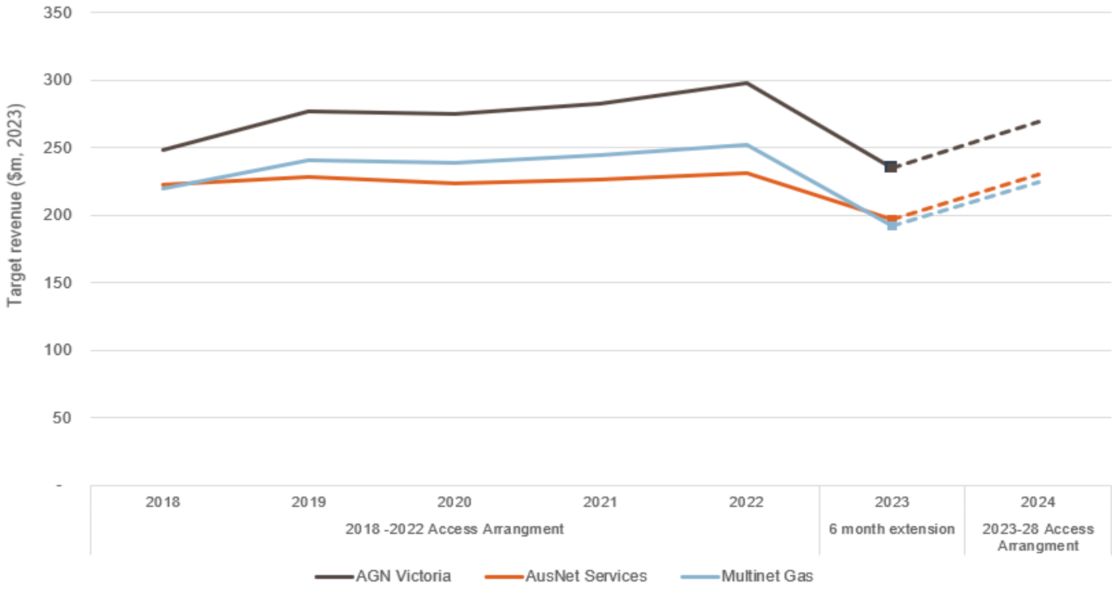
Table 6-2 Gas distribution target revenues and target revenues per customer for 2023 and 2024

Gas DNSP	Distribution target revenue				Distribution target revenue per customer			
	($m 2023)		Variance (2023 to 2024)		($ 2023)		Variance (2023 to 2024)	
	2023	2024	Real	Nominal	2023	2024	2023	2024
Total	1,438	1,573	9%	18%	327	355	17%	9%
Evoenergy	76	77	2%	10%	481	501	12%	4%
Jemena Gas Networks	475	508	7%	15%	318	336	14%	6%
AGN South Australia	263	264	0%	8%	558	553	7%	-1%
AGN Victoria	235	269	15%	23%	313	356	23%	14%
AusNet Services	197	230	17%	26%	247	286	25%	16%
Multinet Gas	192	224	17%	26%	267	311	26%	17%

Source: Target revenue: Gas DNSP annual tariff variation model - Sum of proposed tariff revenues. Customer numbers: Annual RINs - S1.1 'Customer numbers by customer type'.
Note: AER calculation to convert some numbers to $ June 2023 and nominal terms. Distribution revenue per customer calculated by dividing the gas DNSP's distribution revenue by their customer numbers.

The increase has been primarily driven by the Victorian gas DNSPs, with a cumulative increase of 16% in real terms and a nominal increase of 25%. In analysing the increased revenue, the target revenue for 2024 for all Victorian gas DNSPs remains below the target revenues for 2022, which was year 5 of their previous access arrangement.

Figure 6-1 Gas distribution target revenue - Victorian gas DNSPs - $ real 2023



Source: Target revenue: Gas DNSP annual tariff variation model - Sum of proposed tariff revenues.
Note: AER calculation to convert numbers to $ June 2023.

This indicates that the price increases are largely due to the lower revenues from the 6-month transitional extension to the 2018-22 access arrangement. In comparing the target revenues for 2024 to the last 12-month regulatory year in 2022, there is a decrease in real terms of 7% and an increase in nominal terms by 2%.

7 Our plan for future network performance reporting

The dual reporting of electricity NSPs and gas DNSPs follows a plan we made in last year's report to have more timely reporting. We believe this enhances our analysis to stakeholders and their consideration of the electricity and gas regulatory frameworks. In the second half of 2024, we will complete our 2023 performance reporting, by publishing operational and financial performance data in relation to the three 3 scheme (transmission) pipelines - Amadeus Gas Pipeline, Roma Brisbane Pipeline and Victorian Transmission System.

In 2025 we plan to publish the second combined Electricity and gas network performance report earlier, targeting an early 2025 release to provide earlier information for stakeholders.

In the second half of 2024 we will also publish our second Export services performance report. This annual report will provide stakeholders information on the performance of electricity DNSPs in providing distribution services for embedded generators (such as residential solar) to export into the network.

We will undertake targeted engagement on the Export services performance report with stakeholders. We will also follow the same process as this report and circulate preliminary version of these reports to stakeholders for fact checking.

Our work plan also involves investigating future focus areas across the electricity and gas sectors, taking into consideration our new requirements to assess network performance in relation to greenhouse gas emissions and the performance of NSPs in the energy transition.

We will seek stakeholder feedback on potential options for these focus areas, including preparedness of gas NSPs for a low emissions future or how electricity NSPs are managing changes in minimum and maximum demand from solar PV and the implications for network utilisation on electrification of homes, and electric vehicles. In late 2024 we will commence consultation with NSPs on their thoughts on these and other focus areas they believe we should investigate in 2025.

Electricity and gas NSPs will play an integral role in the energy transition. As such we will need to adapt our data collection practices so we can continue to assess NSPs' operational and financial performance throughout the energy transition. We welcome feedback from NSPs and stakeholders regarding the type of data we should collect and what we should analyse in our future reports and focus areas.

8 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
NEL/NER	National Electricity Law and National Energy Rules governs 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 Changes to the NER are made by the AEMC.

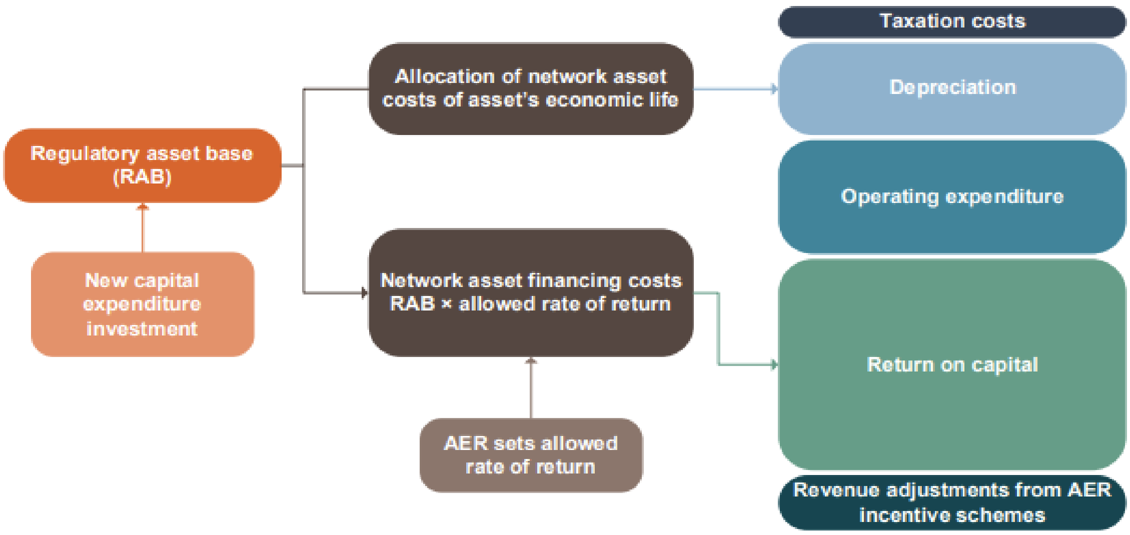
Term	Definition
NEM	National Electricity Market - operating in NSW, Queensland, South Australia, Victoria, Tasmania and the ACT, the NEM is both a wholesale electricity market and the physical power system
Network utilisation	Network utilisation measures the extent that network assets are used to meet customer demand
NGL/NGR	The National Gas Law and the National Gas Rules 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
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

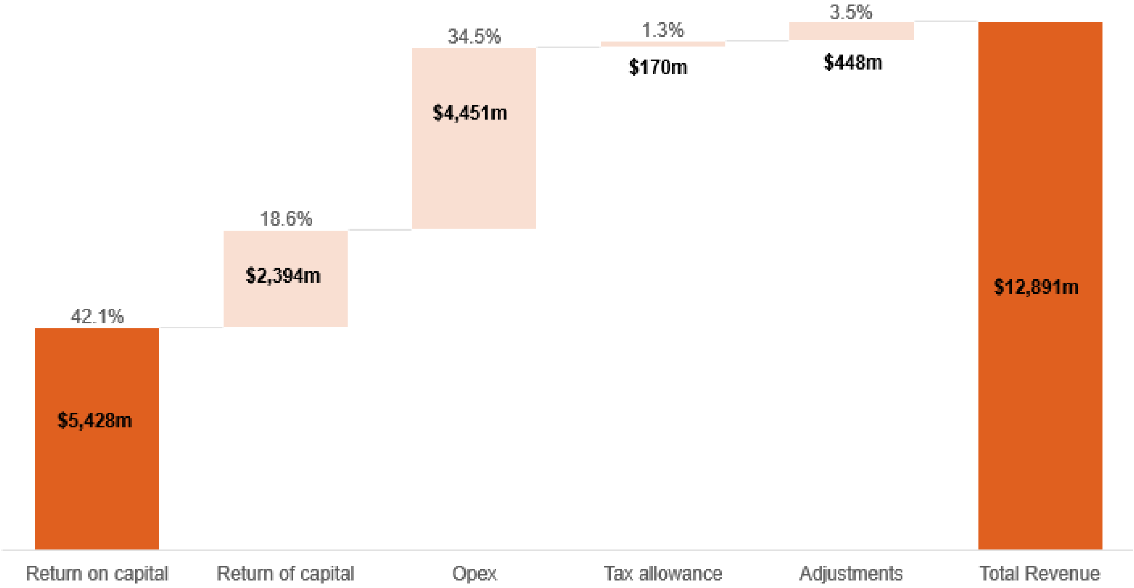


Source: AER analysis, adapted from AER, *State of the Energy Market*, December 2018, p.138.

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.

A.1 Electricity networks were forecast to recover $12.9b in 2023

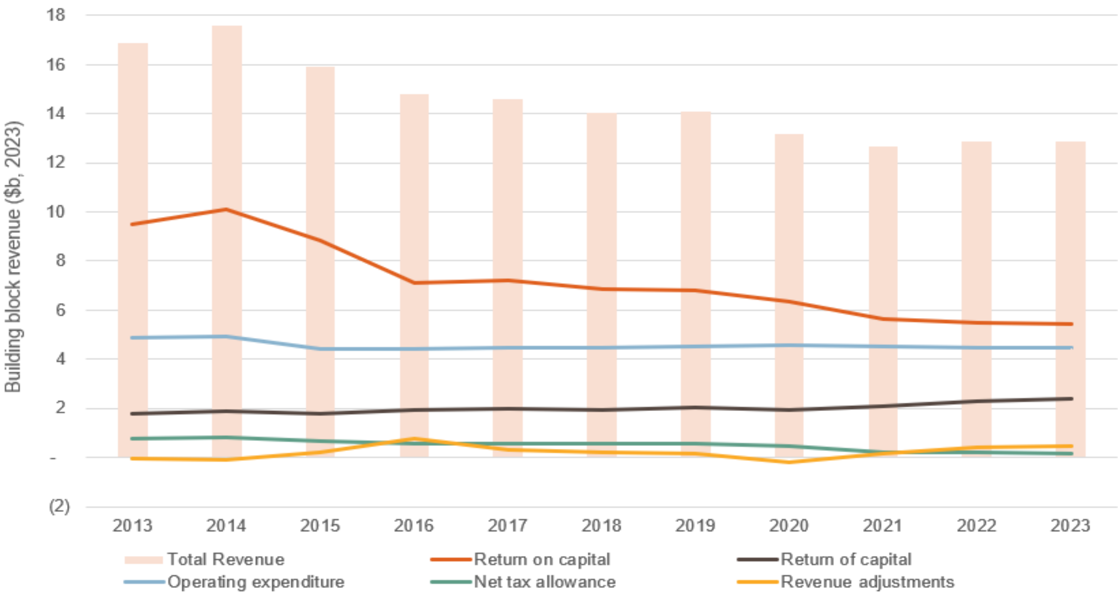
Figure A-2 Building blocks of forecast revenue - electricity NSPs - 2023 - $ real 2023



Source: Forecast PTRM - 'Revenue summary - Building block components. Notes: AER calculation to convert numbers to $ June 2023.

In 2023, return on capital was the largest building block, which is followed by the opex allowance and then return of capital. As provided in Figure A-3 these amounts are reflective of the building blocks from 2013 to 2022, where in real terms there has been a gradual decrease in the return on capital, a gradual increase in return of capital and a constant opex allowance.

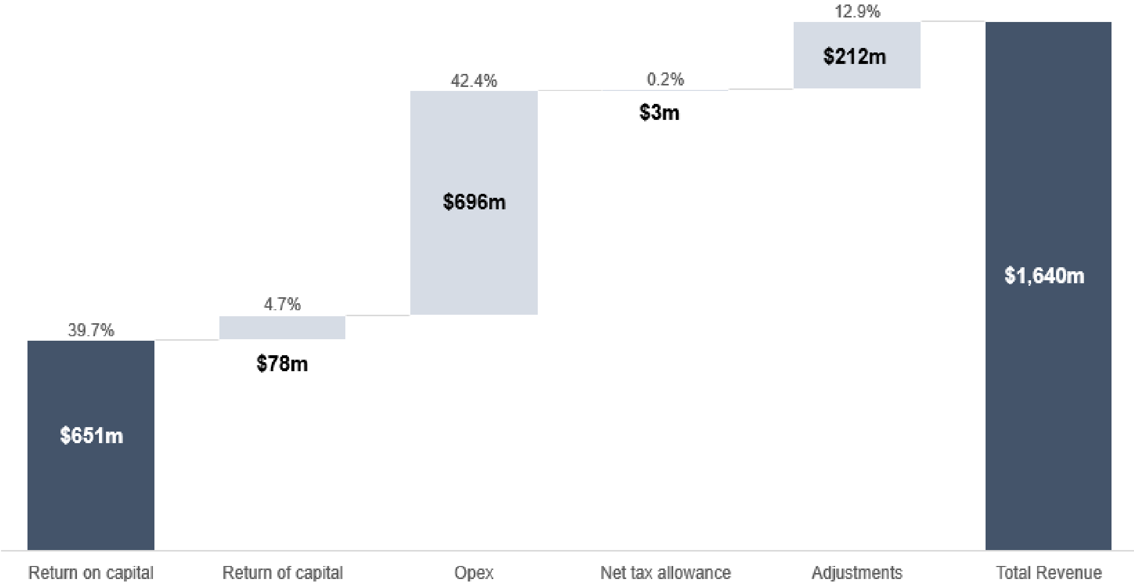
Figure A-3 Building blocks of forecast revenue - electricity NSPs - $ real 2023



Source: Forecast PTRM - 'Revenue summary - Building block components Notes: AER calculation to convert numbers to $ June 2023.

A.2 Gas networks were forecast to recover $1.6b in 2023

Figure A-4 Building blocks of forecast revenue - gas NSPs - 2023 - $ real 2023

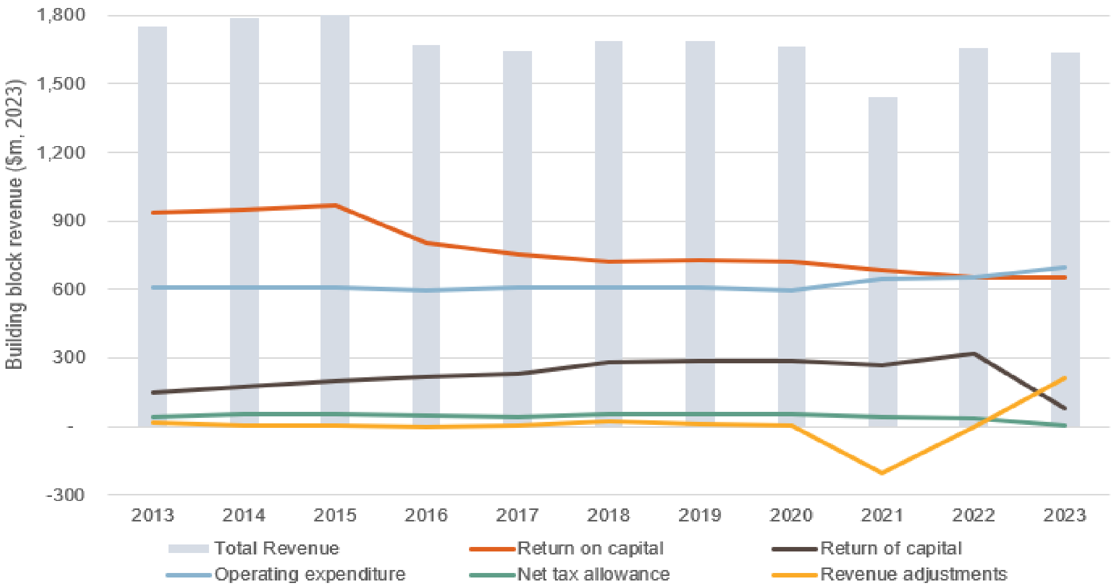


Source: Forecast PTRM - ‘Revenue summary - Building block components.
Note: AER calculation to convert numbers to $ June 2023.

The impact of the annualised six-month regulatory year of the Victorian gas DNSPs is evident in Figure A-5 as the significant inflation has resulted in negative returns of capital. This occurs when the indexation of the CAB is greater than the straight-line depreciation of an NSP’s network assets. Further, the relatively low allowed returns for the six-month period have also enabled the opex allowance to be the largest building block for gas NSPs.

When assessing the 2023 building blocks against the historical building blocks from 2013 to 2022, it illustrates how the low return of capital and higher revenue adjustments are not reflective of the historical trend. Due to this, it is expected that these building blocks will revert to their standard proportion of a gas network costs in 2024.

Figure A-5 Building blocks of forecast revenue - gas NSPs - $ real 2023



Source: Forecast PTRM - 'Revenue summary - Building block components. Note: AER calculation to convert numbers to $ June 2023.

Appendix B: DMIAM outcomes in 2023

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.

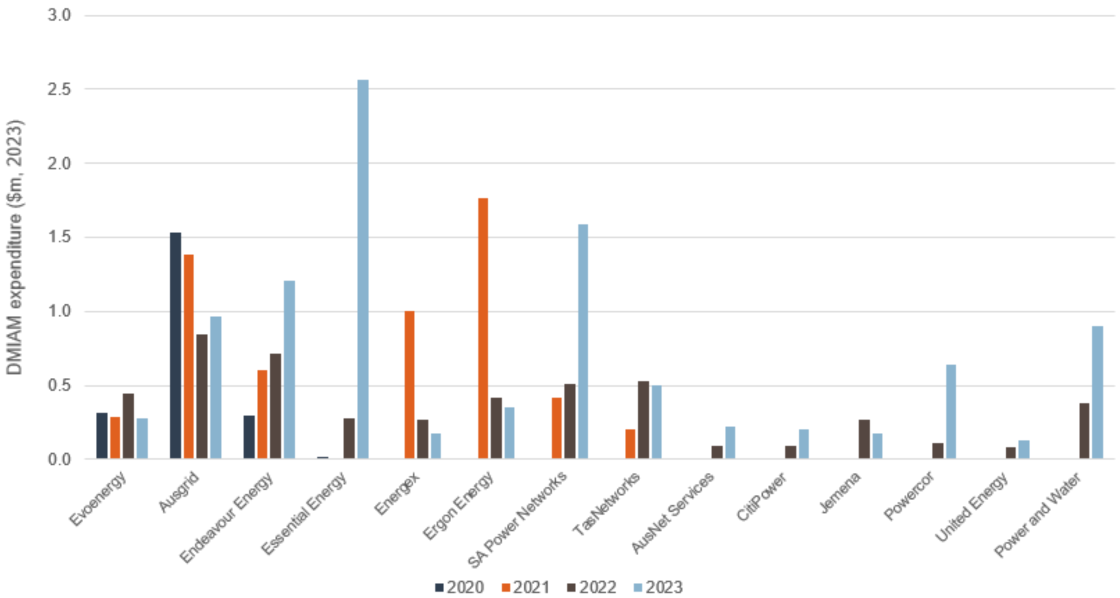
Electricity DNSPs must also provide any other information required to enable an informed reader to understand, evaluate, and potentially reproduce the demand management approach of an eligible project. A key objective of our DMIAM is to assist in enhancing industry knowledge of practical demand management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

B.1 DMIAM outcomes increase in 2023

The number and costs of the projects is increasing yearly, with 18% more projects in 2023 than last year, with total project costs increasing in real terms by 109%.

Figure B-1 Approved DMIAM expenditure - electricity DNSPs - $ real 2023



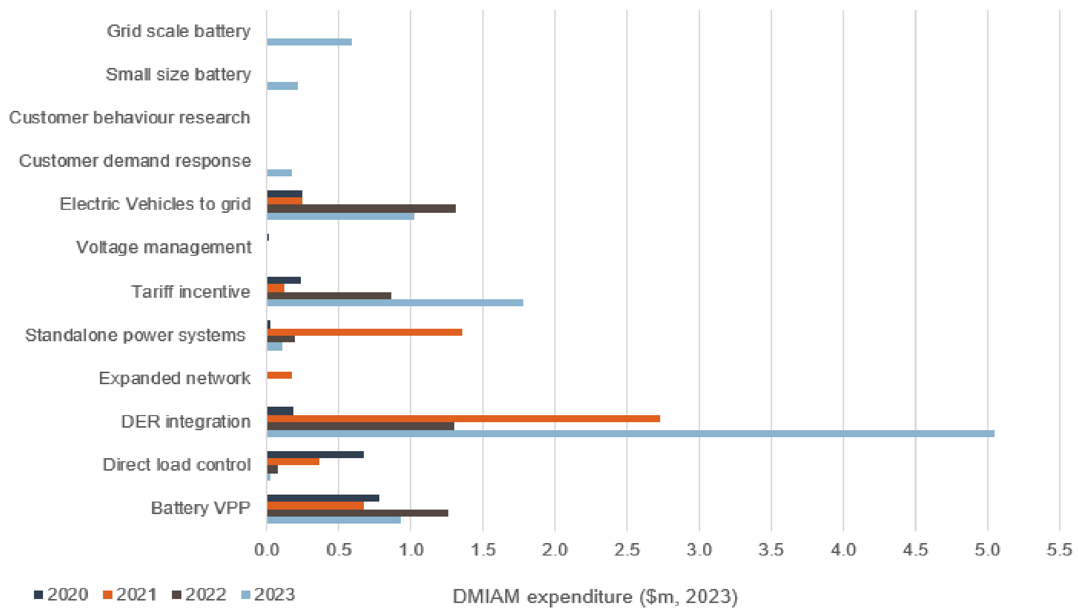
Source: AER analysis

B.2 Electricity distribution networks continue to innovate with DMIAM

Whilst electricity DNSPs have different approaches for utilising DMIAM funding, distributed energy resources integration was the most popular project type and resulted in greater total expenditure than the other project types combined. This is likely in response to the increasing number of domestic and small commercial PV installations on their networks.

Battery virtual power plant (VPP) projects are in decline, likely due to their successful completion and incorporation into BAU activities. Customer behavioural research, Customer demand response and small size battery projects were undertaken for the first time in 2023.

Figure B-2 DMIAM expenditure by category - electricity DNSPs - $ real 2023



Source: AER analysis

Appendix C: 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 the 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. These are discussed in Table 4.

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 C-1.

Table C-1 Factors contributing to differences between RoA and the 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.
ACT Government's feed-in tariffs for large-scale renewable	Electricity NSPs	Evoenergy must apply to the ACT Government to recover reasonable costs in relation to the feed-in tariff for large-scale renewable energy generation. As application 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.

Factor	Sector	Details
energy generation		Due to this, there has been substantial over recoveries of jurisdictional revenue in 2018, 2019 and 2020, and a substantial under recovery in 2021. As a result, when determining the ROA inclusive of jurisdictional schemes, returns in 2018 and 2019 appear higher than they otherwise would, and returns in 2020 and 2021 appear lower than they otherwise would.
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 post-tax revenue model (PTRM) forecast
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 2022 can be found in the ESC's 2017 UAFG benchmark review. 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 roll-forward models (RFMs) for the NSP
- the latest approved or proposed post-tax revenue models (PTRMs) for the NSP
- the NSP's annual data submissions, including through regulatory information notices (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 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 forecast 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 transmission NSPs, we calculate the CAB on as-incurred basis. This entails using the as-incurred capex reported by the gas transmission NSPs 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 D: 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 are as detailed in 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 between electricity NSPs and between 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 7 of the Return of assets 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 roll-forward models (RFMs)
- the latest approved or proposed post-tax revenue models (PTRMs)
- the annual data submissions, including through annual regulatory information notices (RINs) reported to the AER

Information on the revenue and expenditure, depreciation, incentive scheme revenues and payments to calculate EBIT are 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 Reporting 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 E: 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 4 and provide 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 roll-forward models (RFMs) for the NSP
- the latest approved or proposed post-tax revenue models (PTRMs) for the NSP
- annual regulatory information notice (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 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.