Gas network performance report

2023

AUSTRALIAN ENERGY REGULATOR

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1 Overview

This is the AER's third annual gas network performance report ('the report'). In our network performance reports, we identify and analyse key outcomes and trends in the operational and financial performance data collected from the service providers we regulate.

Our aim is to provide accessible information to improve transparency and accountability around network performance under the regulatory regime.

We explore the costs and profitability associated with providing reference services, which reflects a combination of scheme pipelines' productive efficiency, capital market conditions and our regulatory settings.[1] In this way comparing actual performance against forecasts helps to identify and understand the effectiveness of the regulatory regime; thereby supporting informed engagement and objective data-driven debate. This aligns with our objectives for reporting on network performance (see Appendix A), which we developed in consultation with stakeholders before developing our first network performance report.[2]

In developing the 2023 report, we:

- Sought early input from a cross-section of consumer and industry stakeholders on focus areas to explore in this report, as well as in future reports.
- Gave scheme pipelines the opportunity to review the accuracy of our key data inputs.
- Provided scheme pipelines, consumer representatives and other relevant stakeholders the opportunity to review and engage with our analysis.

Our reporting found that the regulatory regime has improved outcomes for consumers over time. In 2022, consumers on average paid less to scheme pipelines for reference services than in any other year since 2011. At the same time, outages have reached record lows whilst scheme pipelines have remained profitable. There have been clear improvements in consumer outcomes since our major regulatory reform package in 2013, whilst consumers also benefited from an external environment comprising low interest rates and inflation. The economic environment has since shifted with higher inflation and tightening of monetary policy resulting in increased interest rates. This has started to affect some of the performance measures and cost inputs reported for 2022. The effect of these changes is likely to have a greater effect on our measures in future years.

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1 Regulatory settings include how we forecast expenditure and share the rewards of achieved efficiencies between scheme pipelines and consumers.

2 AER, *Objectives and priorities for reporting on regulated electricity and gas network performance 2020*, 2020, accessed 4 April 2022.

Key findings

- **Revenue in 2022** decreased for distribution scheme pipelines by 2.5% since 2021. Transmission scheme pipeline revenue for APA Victorian Transmission System (VTS) increased by 3.8%.
- **Distribution service** outcomes for distribution pipelines were strong. Distribution outages reached a record low, driven by a 44% reduction in planned outages. Unaccounted for gas (UAFG) as a proportion of gas delivered was the second lowest reported level since 2011.
- **Returns on assets** for scheme pipelines fell on average by 90 basis points based on the previous low reported in 2021 and are now 4.3%.[3]
- **Earnings before interest and tax per custome**r (EBIT per customer) for distribution pipelines fell to its lowest recorded level of $116. Lower allowed rates of return influenced declines in revenue and therefore EBIT.
- Returns on **regulated equity** were higher than our benchmark allowed return on equity on average. In 2022, the average return on regulated equity across scheme pipelines increased to 9.0%, due to actual inflation being higher than forecast inflation.
- **Demand and differences in forecast and actual revenue** meant that, on average, scheme pipelines have consistently recovered more revenue than forecast since 2011. Higher growth in distribution customers than forecast appears to have contributed to the demand driven outperformance Gas scheme pipelines are regulated under price caps, which incentivise them to increase demand where beneficial to reduce the unit costs faced by consumers.
- **Expenditure** for distribution scheme pipelines in 2022 fell to its lowest point since 2011. A decrease in capital expenditure (capex) of 16.6% was the main driver. In contrast, transmission expenditure reached a new high driven by APA VTS's expansion capex of $130.7 million in 2022.[4]
- **Capital bases** increased marginally in 2022, with the 8.2% increase for transmission offsetting the 1.2% decrease for distribution.

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3 It is important to note, while we aim to publish high quality data in some cases the data used to report on performance may be revised to correct for errors. Our processes ensure the quality of data is reviewed and remains fit for purpose. The outcome is that revisions to underlying data and required adjustments may result in variation from previously published results.

4 AER, *APA VTS Gas access arrangement 2023-27 – Final Decision – Attachment 5 – Capital Expenditure*, December 2022, p.6.

2 Scope of the 2023 report

This report:

- Focusses on the scheme pipelines we regulate– Section 2.1
- Updates our previous analysis to cover data for the 2022 regulatory year – Section 2.2
- Focuses on core measures – Section 2.3

Our detailed analysis on core measures, including operational performance and profitability measures are presented in section 3 and section 4.

2.1 Reporting on scheme pipelines

In this report, we focus on the scheme pipelines for which we approve access arrangements that cap reference prices. This report does not cover scheme pipelines that were previously under light regulation, nor does it cover non-scheme pipelines. See our 2023 State of the energy market report for a description of the recent changes to pipeline regulation.[5]

Table 2-1 summarises the scheme pipelines and services we analyse in this report.

Table 2-1 Scheme pipelines and gas pipeline services in this report[6]

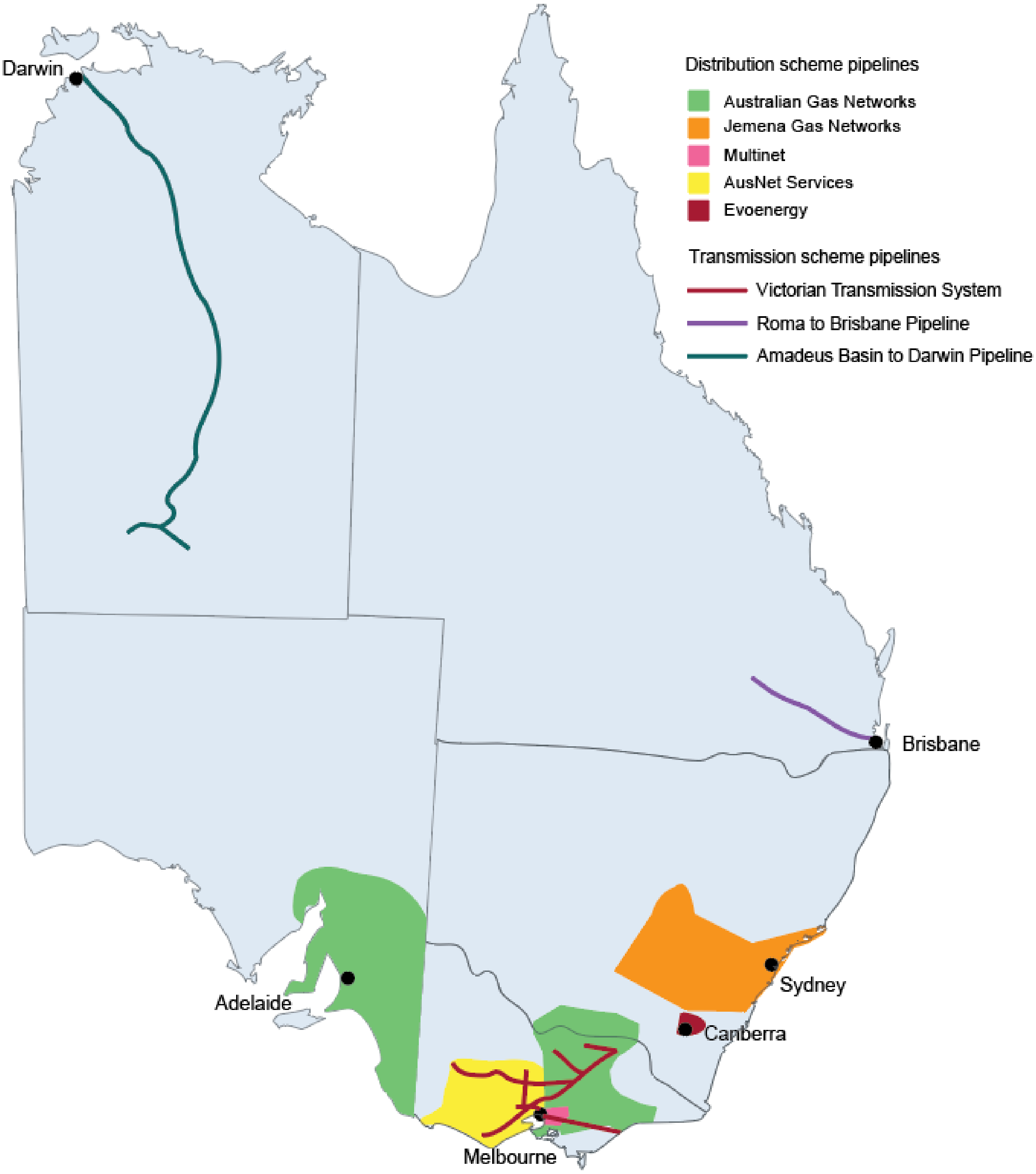
 **Distribution**	Urban and regional distribution networks, which are clusters of smaller pipes or mains that transport gas to customers in local communities. Fully regulated services are called haulage reference services, although this report refers to them as 'reference services' for simplicity.	Providers of reference services: • Jemena Gas Networks (JGN) in NSW • Evoenergy Gas in ACT • Australian Gas Networks (AGN) in South Australia • Multinet Gas in Victoria • AusNet Gas Services in Victoria • Australian Gas Networks (AGN) (Victoria and Albury) in NSW and Victoria
 **Transmission**	Long haul transmission pipelines that transport gas from producing basins to major population centres, power stations and large industrial and commercial plants. These transmission scheme pipelines transport gas to many industrial customers through a direct connection. Fully regulated services are called reference services.	Providers of reference services: • Amadeus Gas Pipeline (Amadeus) in the Northern Territory • Roma Brisbane Pipeline (RBP) in Queensland • Victorian Transmission System (VTS) in Victoria

5 AER, *State of the energy market*, 2023, Box 5.1.

6 Source: AER analysis.

Figure 2-1 highlights where the three transmission and six distribution scheme pipelines operating outside of Victoria (where VTS operates). The transmission scheme pipelines operate in different geographical regions to the distribution scheme pipelines.

Figure 2-1 Scheme pipelines covered in this report



Source: AER analysis adapted from AER, State of the Energy Market 2023, Figure 5.1.

Distribution scheme pipelines have a strong focus on serving domestic load and only operate in temperate to cooler regions given the efficiency of gas heating. In contrast:

- The Amadeus gas pipeline operates in the Northern Territory and transports gas north to Darwin and south towards Alice Springs. It sources gas from the Blacktip gas fields in the Bonaparte Basin and from the Palm Valley and Mereenie gas fields in the Amadeus Basin.[7] This gas is predominantly used for electricity generation.

- The VTS operates in Victoria and supplies gas to industrial and electricity generation customers and to distribution scheme pipelines who supply residential and commercial customers; AGN (Albury and Victoria), Multinet Gas and AusNet Gas Services. The VTS also transports gas to NSW via the Moomba–Sydney Pipeline and to South Australia (SA) via the South East Australian Gas Pipeline. The VTS primarily sources gas from offshore gas fields in the Gippsland, Bass and Otway basins.[8] The VTS also transports gas from the Dandenong liquified natural gas storage facility, Iona underground storage and Cooper Basin.
- The RBP operates in Queensland and sources gas from the Bowen–Surat basin via the Wallumbilla supply hub, Kogan North gas plant and Peat lateral pipeline. The RBP transports gas between the Wallumbilla supply hub, Brisbane, and regional centres along its route.[9] This gas is primarily used for electricity generation and as a feedstock in industrial activity but is also supplied to eastbound retail customers and westbound for trading.

Table 2-2 highlights the key differences between transmission and distribution. For further information, a detailed analysis of these differences is in our 2022 gas network performance report.[10]

Table 2-2 Differences in distribution and transmission pipeline services

	Distribution	Transmission
Customer base	Over 97% residential and less than 0.04% industrial. However, around 50% of the gas that distribution scheme pipelines deliver goes to commercial and industrial customers.	Amadeus in the Northern Territory and RBP in Queensland mainly transport gas to large industrial users or generators (with RBP also providing services to eastbound retail customers). VTS transports gas to 3 of the 6 distribution scheme pipelines (as well as directly to other large customers).
Trends in pipeline length	Annual average growth of 1.1% per year over 2011–2022 to accommodate growth in connections, although this is unlikely to continue with new jurisdictional policies.[11]	Steady and more closely reflects the geographic size of the network rather than customer density.

7 AEMC, *NT: Amadeus Gas Pipeline*, AEMC, 2022, accessed 31 August 2022.

8 AEMC, *VIC: Victorian Transmission System*, AEMC, 2022, accessed 31 August 2022.

9 AEMC, *QLD: RBPBrisbane Pipeline*, AEMC, 2022, accessed 31 August 2022.

10 AER, *Gas network performance report*, 2022, Section 3.2, pp. 13–20.

11 New homes in Victoria are required to be all electric from 1 January 2024: Victoria State Government, *Victoria's gas substitution roadmap*, accessed 25 August 2023. In 2020, the ACT committed to legislating to prevent new fossil fuel gas network connections in greenfield residential developments. It also committed to a goal of no new gas connections to future infill developments from 2023. ACT Government, *Regulations for the prevention of new fossil fuel gas network connections – Issues paper*, 2023, p. 12.

	Distribution	Transmission
Trends in demand	Gas delivered has changed little overall and has declined 24% for industrial users since 2011.	Transmission gas withdrawals are 9.5% higher than in 2012 but has declined since peaking in 2017.
Differences in data	Includes reporting on UAFG and service outages.	Higher prevalence of confidential data due to smaller, more easily identifiable customer base
Pressure type	Consists of mainly medium (7 to 1,050 kPa) and high (>1,050 kPa) pressure mains. There is a decreasing number of low-pressure mains.	Typical pressure is between 10,000 and 15,000 kPAs.[12]
Material type	Predominately and increasingly plastic (polyethylene and polyamide). Other materials include steel, protected steel (with polyethylene coating), cast iron, PVC.	Mostly steel[13]

2.2 The 2022 regulatory year

This report includes data for regulatory year 2022, which is:

- 1 July 2021– 30 June 2022 for Evoenergy Gas, JGN, AGN (SA), Amadeus and RBP.
- 1 January 2022– 31 December 2022 for AGN (Albury & Victoria), AusNet Gas Services, Multinet Gas and APA VTS.

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

The source data for figures in this report are found in our:

- operational and financial performance datasets,
- gas annual regulatory information notices (annual RINs),
- roll forward models (RFMs) and
- post-tax revenue models (PTRMs).

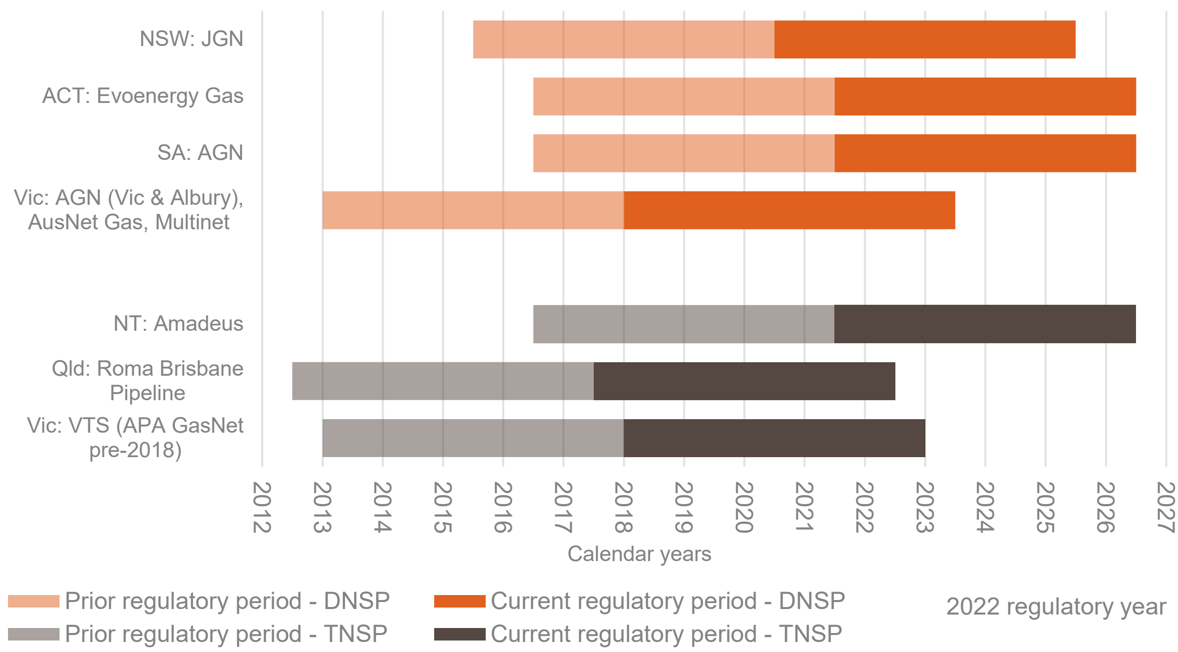
Specific data sources and calculations are stated in the source notes under each figure. In general, data on actuals for the capital base and capex are sourced from the relevant final decision RFM or annual RIN if no RFM is available. Other data on actuals and forecasts are sourced from the annual RINs and final decision PTRMs, respectively.

12 Australian Pipelines and Gas Association (APGA), *Pipeline Facts and Figures*, APGA, 2021, accessed 29 August 2021.

13 AER, *Regulating gas pipelines under uncertainty*, November 2021, p. 14.

Access arrangements generally apply over 5 years with the AER's revenue decisions made in a staggered cycle (Figure 2-2). Due to this, changes in regulatory approaches or market conditions affect scheme pipelines gradually.

Figure 2-2 The 2022 regulatory year in the staggered decision timetable



Source: AER analysis of access arrangement periods also available on the AER website.

2.3 Focus on core measures

This report focuses exclusively on core measures. In our previous reports we also included detailed analyses on focus areas representing emerging issues of stakeholder interest (summarised in Table 2-3).

Potential focus areas identified last year as emerging issues of stakeholder interest could be included as focus areas in 2024. These areas include (1) scheme pipeline actions to prepare for a low carbon future and (2) analysis of demand forecasting and actual demand. We understand these remain topics of interest for consumer groups. In 2024, we will consult with stakeholders to determine if more pertinent topics have since arisen (see Section 5 for more detail).

Table 2-3 Previous gas focus areas

Report	Focus area	Outcome
2022	Introduction of the return on regulated equity.	Subsequent reports include returns on regulated equity.
	Impact of COVID on demand and revenue.	Analysis confirmed the low risk of scheme pipelines to these types of economic shocks.
	Changes in asset age profiles.	Analysis to segue into further work.

Source: AER gas network performance reports.

3 Operational performance in 2022

In this section, we look at the following core performance outcomes:

- revenue—the cost to consumers of reference services (section 3.1)
- expenditure (section 3.2)
- capital bases (section 3.3)
- service outputs (section 3.4).

Where relevant, we also focus on how outcomes in 2022 relate to longer term trends in performance and how those outcomes compare to forecast amounts. We do not directly investigate whether the relationship between expenditure and service outputs is productively efficient. Rather, we explore the costs and profitability of providing reference services, which reflects a combination of scheme pipelines' productive efficiency, capital market conditions and our regulatory settings. Regulatory settings include how we forecast expenditure and share the rewards or penalties of over and under performance between scheme pipelines and consumers.

3.1 Revenue

In this section, we explain how scheme pipelines forecast and collect revenue under the regulatory regime and analyse:

- The revenue that scheme pipelines have collected from consumers in providing reference services.
- The major drivers of this revenue, being building block revenue forecasts and demand.

3.1.1 Revenue under the price cap form of control

All scheme pipelines' reference services are regulated under a weighted average price cap form of control. This begins with establishing a building block revenue forecast.[14] Then, having regard to forecast demand over the access arrangement period, we convert this building block revenue forecast into:

- A set of initial year tariffs
- A series of 'X-factors'[15] which along with actual inflation, changes in demand and other factors constrain annual price increases for those tariffs during the access arrangement period. X-factors govern real annual price changes arising from forecast revenue requirements.

Changes in forecast building blocks are a key determinant of the costs that consumer face. However, under price caps, scheme pipelines can earn above or below forecast revenue

14 The process for establishing a building block forecast also applies to revenue caps. Details on revenue caps (which apply to electricity networks) are provided on the AEMC's network regulation webpage.

15 The X-factor is used with CPI to smooth the revenue a scheme pipeline 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.

over time due to actual demand being higher or lower than forecast. This differs from revenue caps where revenue over or under recoveries ('overs and unders') in any year are carried forward and accounted for to provide revenue certainty. We discuss the effect of demand as a driver of revenue outcomes in section 3.1.5.

Different forms of control have their own strengths and limitations. A major feature of weighted average price caps relative to revenue caps is that they expose scheme pipelines rather than consumers to demand risk within the access arrangement period. This results in specific strengths and limitations by:

- Incentivising scheme pipelines to develop and efficiently price new and higher quality services to increase demand where the revenue is greater than the cost. Given there are high fixed costs and relatively low variable costs in providing reference services, increased demand would typically lower the unit costs of those services.
- Incentivising scheme pipelines to stimulate demand, reduces incentives for demand management. This incentive appears to be disconnected from current net-zero objectives, unless the gas is sourced from low carbon alternatives (for example, green hydrogen or biogas).

We discussed these strengths and weaknesses in our issues paper on 'Regulating gas pipelines under uncertainty'.[16] In this context, we noted that uncertainty around future gas demand and decarbonisation policy objectives might present a need for us to change the form of control. We considered issues relating to the form of control for scheme pipelines as part of our consultation on access arrangements and our gas distribution network tariffs review.[17]

Our decision was to not make sector wide changes to distribution scheme pipeline tariff variation mechanisms and tariff structures. Instead, we will review these issues on a case-by-case basis in the context of individual access arrangement reviews. We will do this by building consideration of tariff variation mechanisms and tariff structures into the existing reference service proposal assessment, undertaken in advance of each access arrangement review.

Under this new approach, distribution scheme pipelines will submit to the AER a combined proposal for reference services, tariff variation mechanism and tariff structure 12 months ahead of the access arrangement review. We will then release a non-binding decision on the combined service/tariff mechanism/tariff structure proposal within 6 months of its submission to us. We expect distribution scheme pipelines to undertake substantive stakeholder consultation to inform their tariff variation and tariff structure (and reference service) proposals.

3.1.2 Revenue analysed in this report

In this report we refer to forecast and actual revenues as revenue collected from providing reference services, which can also include revenue from non-reference services. This reflects that after we use the building block approach to determine a scheme pipeline's

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16 AER, *Regulating gas pipelines under uncertainty: Information paper*, November 2021, pp. 54–55.

17 AER, *Gas distribution network tariffs review 2023*, accessed 31 October 2023.

economically efficient revenue, that revenue is allocated between reference and other services based on relative costs.[18]

Categorising revenue in this way does not materially change our analysis, as reference prices influence the price that scheme pipelines may charge for non-reference services. This is because scheme pipelines must make at least one reference service available, which also serves as a benchmark for the price of other pipeline services.[19]

This factor results in some differences between transmission and distribution scheme pipelines. Distribution scheme pipelines serve a high proportion of residential customers and predominantly provide reference services. In contrast, due to having a higher proportion of large customers with bespoke commercial arrangements, transmission scheme pipelines = provide a higher proportion of non-reference services. This higher proportion of non-reference services can make it more difficult to forecast revenues.

We report distribution revenue on a per customer basis as we consider this indicates the cost of reference services to consumers. However, we caution that this does not perfectly measure the costs of reference services for specific customers. A customer's gas bill depends on several factors, including their consumption levels as well as haulage costs. Scheme pipelines also do not collect revenue evenly across customers. For instance:

- Commercial and industrial customers who consume relatively large amounts of gas, despite being a small proportion of total customers, also provide a relatively high proportion of revenue to scheme pipelines. As such, we only report revenue per customer for distribution pipelines because transmission scheme pipelines generally supply a small number of large customers, making relative performance difficult to interpret based on per customer measures.
- Under a price cap, declining revenue at an aggregate level could also reflect changing usage within a particular customer class. If so, these aggregate impacts will not be consistent across customer classes.

3.1.3 Revenue and revenue per customer

In 2022, revenue for providing reference services:

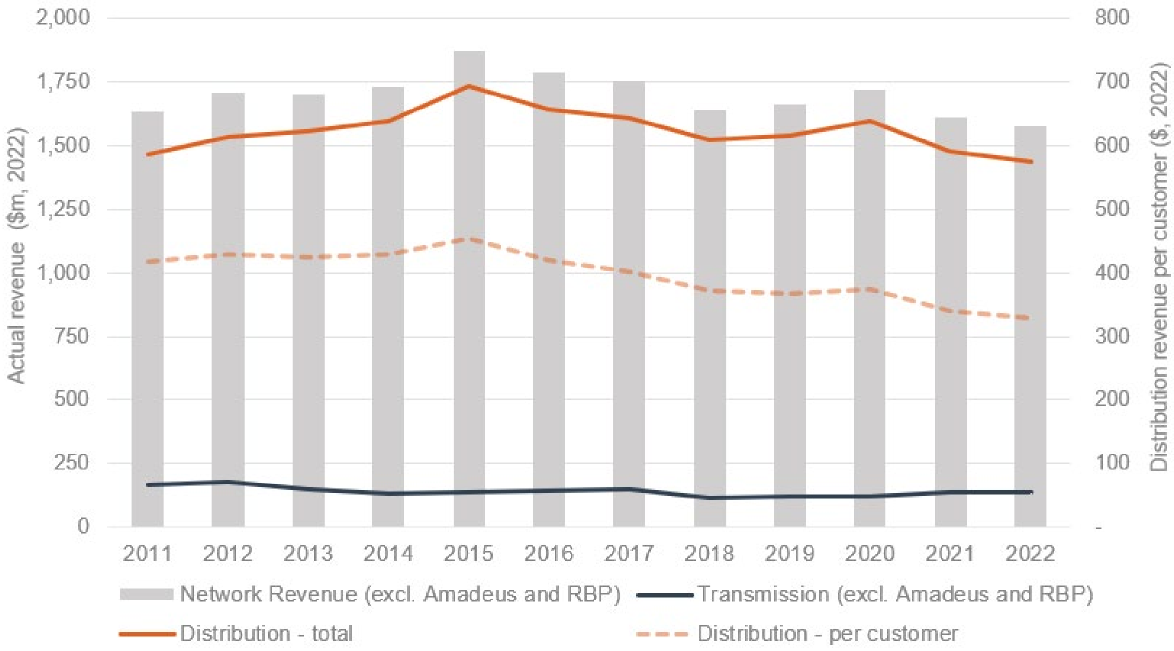
- decreased for distribution scheme pipelines by 2.5% from 2021.
- increased for VTS by 3.8% from 2021.

Figure 3-1 shows how the amount of revenue recovered has changed over time, both on a total and per customer basis.

18 See National Gas Rules, Rule 76 on the building block approach and Rule 93 on revenue allocation.

19 National Gas Rules, 47A(1) requires scheme pipelines to identify at least one reference service, having regard to the reference service factors in 47A(15).

Figure 3-1 Total and per customer reference service revenue



Source: Annual RINs – S3.1 Reference services and Annual RINs – S1.1 Customer numbers by customer type.

Note: AER calculation to convert into $2022 terms and to calculate distribution revenue per customer as reference service revenue ÷ customer numbers. Transmission data excludes Amadeus and RBP's revenue due to confidentiality.

In 2022, the total reference service revenue decreased for distribution scheme pipelines by 2.5% over the previous year to its lowest point since the start of the data series in 2011. The relative decrease in revenue per customer was even more pronounced due to an average annual increase of 1.9% in distribution pipeline customer over the same period. In 2022, distribution scheme pipeline revenue was $328 per customer compared to $455 per customer at its peak in 2015.

Evoenergy was the only distribution scheme pipeline to have negative customer growth in 2022—a decrease of 0.25%. Jurisdictional policies to prohibit new gas connections, primarily for residential homes and in some instances business premises will effectively cap retail customer numbers. In addition, policies to incentivise existing customers towards electrification is likely to contribute to a decline in customer numbers overtime (see box below). All else being equal, lower customer numbers will increase revenue per customer.

Policies affecting customer numbers on distribution scheme pipelines

Jurisdictional policies and regulations have recently been changing to limit the number of new gas connections to encourage consumers towards a low carbon future. We are already starting to see lower levels of customer growth compared in previous years. We will continue to monitor customer numbers and changes in demand in response to these policies in the transition to net-zero.

Governments in the ACT and Victoria previously mandated gas infrastructure to be included in new developments. The ACT removed its requirement in 2020[20], and Victoria in August 2022.[21]

The ACT Government developed a pathway to phasing out fossil-fuel gas by 2045 and has identified electrification as the best path, with renewable gas being considered for niche applications. In the initial phase of this pathway, greenfield suburbs will not connect to gas mains and from 2023, new gas connections will cease for future infill developments.[22] Regulations will be introduced preventing new gas connections for new homes and business premises.[23]

In Victoria, new homes are required to be all electric from 1 January 2024.[24]

Recent announcements by the Premiers of South Australia and New South Wales (NSW) indicated their respective Governments would not ban new gas connections.[25] The South Australian Government is pursuing a policy of lower emission gas blends, including hydrogen.

In addition, there are several government incentives in place to support electrification. For instance, the Australian Government's Energy Savings package offers, among other things, financial incentives for electrification along with energy efficiency improvements.[26] The ACT government offers rebates and interest-free loans to support electrification and energy efficiency upgrades in the home.[27]

Figure 3-2, illustrates a notable decrease in NSW distribution revenue in 2021. This was largely driven by a downward revenue adjustment to JGN of $169 million ($ Jun 2020) over its 2020–25 access arrangement period to correct for previous overcompensation.[28] Nevertheless, distribution revenue continued to decline in 2022. JGN's revenue reduction in 2021 was due in part to a lower allowed return on equity under the 2018 rate of return

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20 ACT Government, *Regulations for the prevention of new fossil fuel gas network connections – Issues paper*, 2023, p. 15.

21 Victorian Government, *Gas Connection Amendment VC221*, 4 August 2022.

22 ACT Government, *Media release– Power Canberra: Our pathway to electrification*, 4 August 2022, accessed 25 August 2023.

23 ACT Government, *Canberra is electrifying: Towards a net zero emissions city – Integrated Energy Plan positions paper*, August 2023, p.12.

24 Victoria State Government, Victoria's gas substitution roadmap, accessed 25 August 20233

25 Ludlow, M, '*Victoria left to go it alone on gas ban to new homes*', Australian Financial Review, 31 July 2023, viewed 4 August 2022

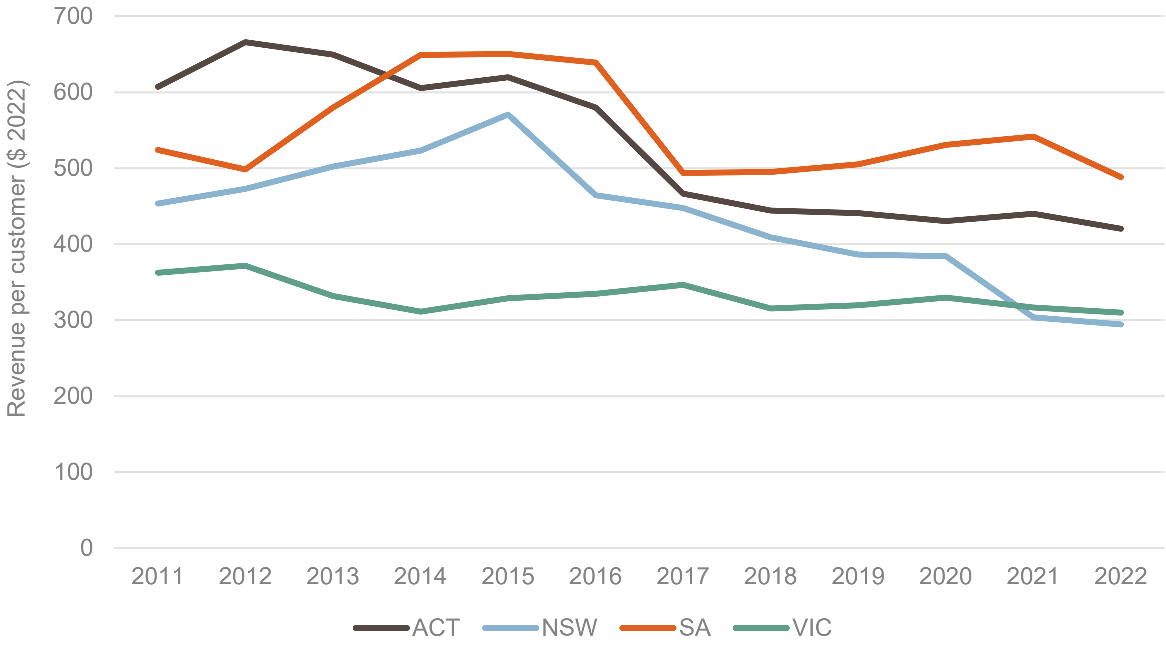
26 Available through the Household Energy Upgrades Fund and the Small Business Energy Inventive. See Ministers: Treasury portfolio, *Media release – Helping Australians save energy, save on energy bills*, 9 May 2023.

27 Everyday climate choices, *Home energy support: Rebates for homeowners*, accessed 25 August 2023.

28 For more on the origin and effect of the previous overcompensation and details on the revenue adjustment, see AER, *Gas network performance report*, December 2021, pp. 38–40.

instrument. In 2022, allowed returns on equity were also reset for AGN (SA) and Evoenergy in the ACT, resulting in the application of a lower risk-free rate and equity beta.[29]

Figure 3-2 Distribution reference service revenue per customer by jurisdiction



Source: Annual RINs – S3.1 Reference services and Annual RINs – S1.1 Customer numbers by customer type.

Notes: AER calculation to convert into $2022 terms and to calculate revenue for each jurisdiction ÷ number of customers for each state/jurisdiction.

3.1.4 Building block revenue forecasts

All scheme pipelines are regulated under price caps. Initial year prices and 'X-factors' governing annual tariff variations are set using a forecast of revenue 'building blocks' that an efficient scheme pipeline would require to provide reference services. These include:

- A return on the capital base — A return on capital to compensate investors for the opportunity cost of funds invested in the scheme pipeline.
- Regulatory depreciation of the capital base — A return of capital to return the initial investment to investors over time adjusted for indexation of the capital base.
- Forecast capex — The capex incurred in providing reference services. This mostly relates to expenditure on assets with long lives, the costs of which are recovered over several access arrangement periods. The forecast capex approved in our decisions directly affects the projected size of the capital base and therefore the revenue generated from the return on capital and regulatory depreciation building blocks.

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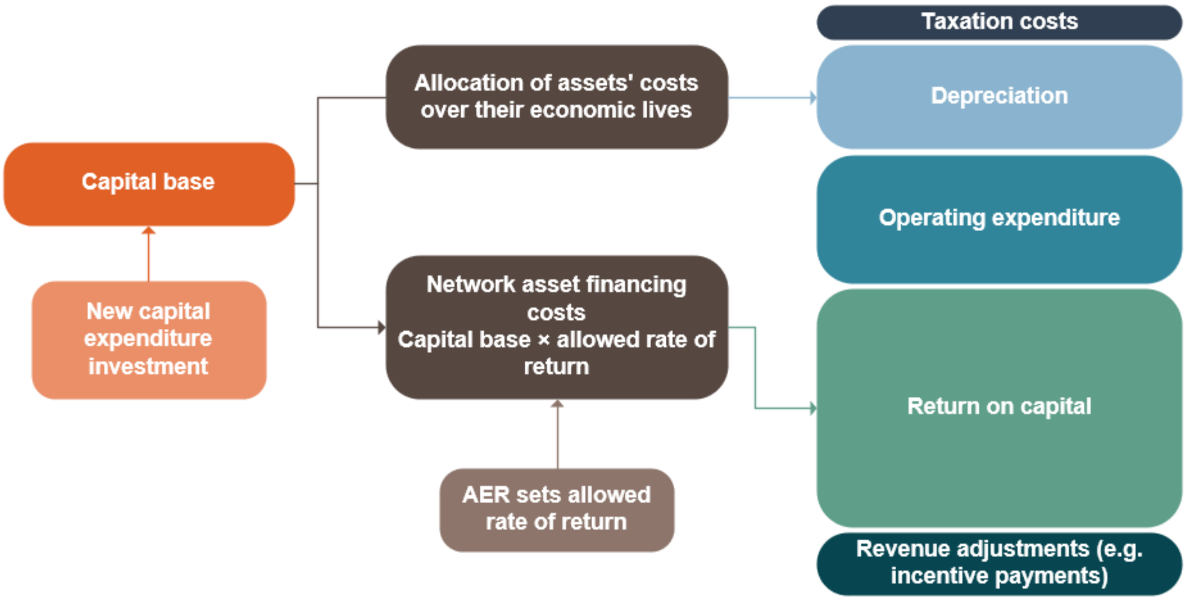
29 A lower interest rate environment prevailed in 2021 than in 2016, and the equity beta under the 2018 rate of return instrument dropped to 0.6 from the previous 0.7. See AER, *Rate of return instrument 2018*, Accessed 2 November 2022. Following these changes, the allowed return on equity dropped from 7.1% to 5.07% for Evoenergy and 5.37% for AGN (SA).

- Forecast operating expenditure (opex) — The operating, maintenance and other non-capital expenses incurred in providing reference services. In contrast to capex, forecast opex translates directly into allowed revenue in the years we expect the expenditure to occur.
- The estimated cost of corporate income tax.
- Revenue adjustments — Adjustments to revenue, which include adjustments for accrued rewards or penalties from incentive schemes. Incentive schemes are regulatory tools designed to promote the interests of consumers by encouraging efficiency and improved service outcomes. In the case of scheme pipelines, these relate principally to making efficiency improvements in opex and capex. These desirable behaviours should deliver better outcomes for consumers and promote achievement in the National Gas Objective.

Figure 3-3 The building block model to forecast revenue



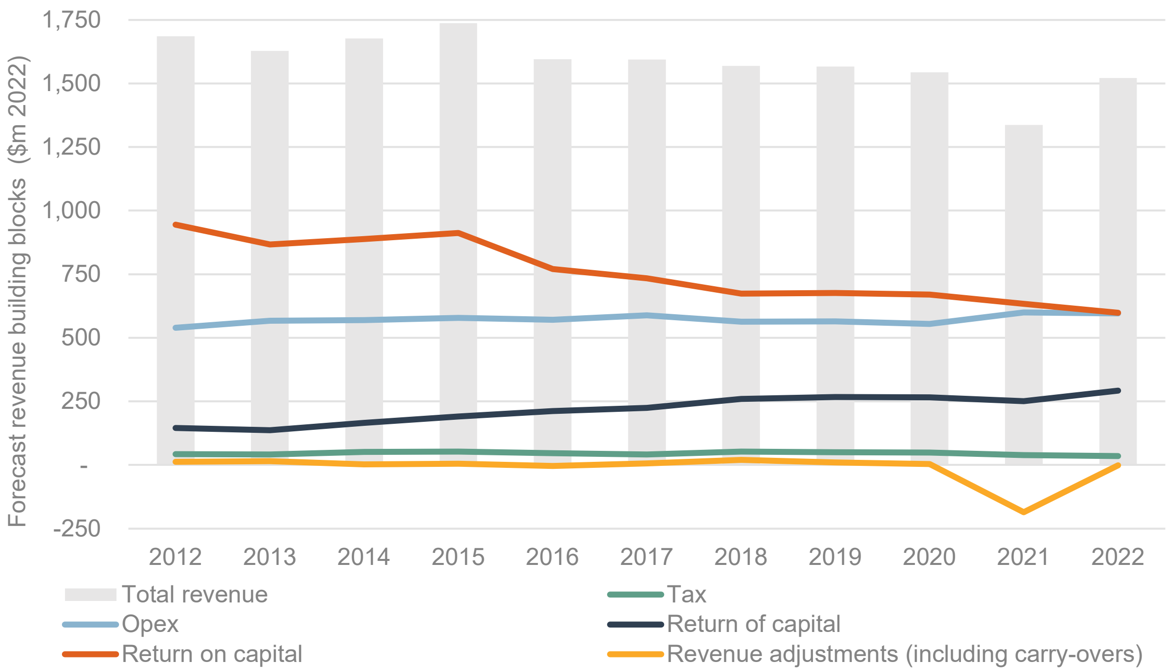
Source: Adapted from AER, State of the Energy Market, December 2018, p. 138.

Excluding the impact of the large downwards revenue adjustment to JGN in 2021[30], forecast revenue has been trending downwards for scheme pipelines overall since 2015:

- Returns on capital (driven by the allowed rate of return and the capital base) have been the largest source of declining forecast revenue since 2015. While capital bases increased (particularly in Victoria and SA), allowed rates of return decreased to have a much larger impact.
- Depreciation (returns of capital) has increased. This was largely driven by capital base growth from connections and mains replacement programs in South Australia and Victoria, and some material investments in assets with shorter economic lives.
- Forecast opex has gradually increased.

Figure 3-4 illustrates how forecast revenue has changed since 2012 for scheme pipelines.

Figure 3-4 Forecast revenue building blocks – scheme pipelines



Source: PTRMs 53.01 – Revenue summary – Building block components.

Note: AER calculation to convert revenue into $2022 terms.

30 A one-off downwards revenue adjustment applied to JGN in 2021 to return additional revenue provided while its final access arrangement was undergoing remittal. For more details, see AER, *Gas network performance report*, December 2021, pp. 39–41.

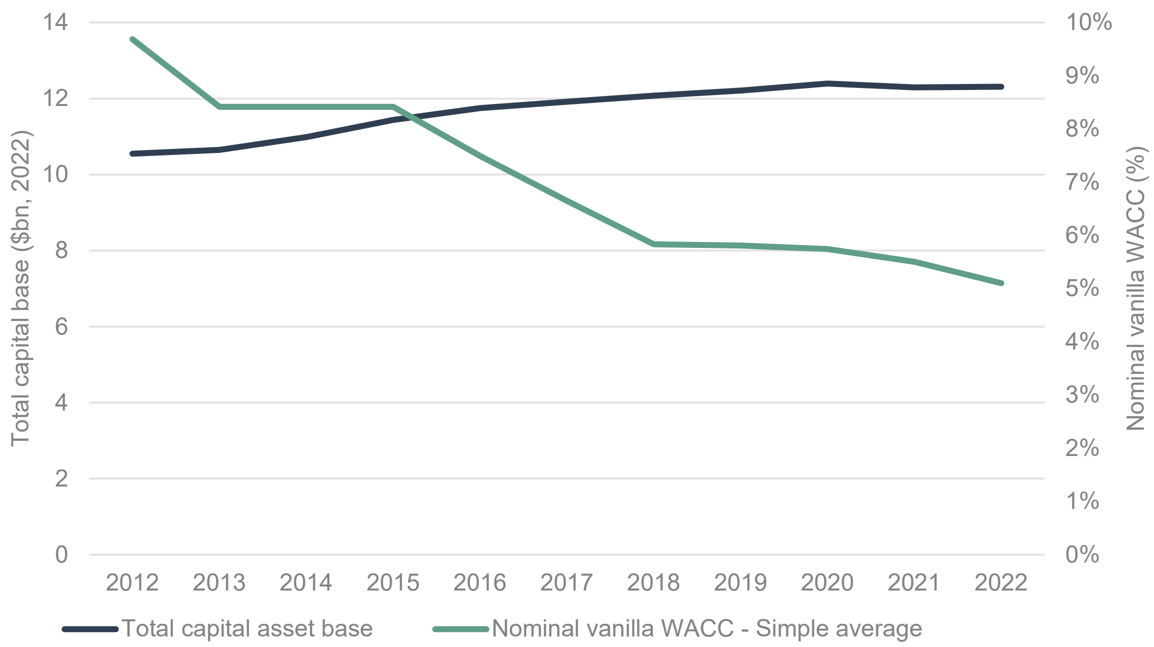
Declining forecast revenue from lower allowed returns on capital

Scheme pipelines are capital intensive businesses. The return on capital is one of two building blocks through which scheme pipelines recover their capital costs. The return on capital is the product of:

- The capital base—the remaining economic value of assets used to deliver the reference services; and
- The rate of return on capital—the costs of raising each dollar of capital, typically expressed as a percentage.

In recent years, we have observed and forecast declining allowed returns on capital in our access arrangement decisions. Holding other factors constant, this has reduced overall revenue requirements. However, a material growth in capital bases has offset these reductions. Capital base growth is driven by investment in network assets, which scheme pipelines finance through issuing debt or raising equity. These two effects are set out in Figure 3-5.

Figure 3-5 Changes in capital bases and allowed returns – scheme pipelines



Source: WACC from PTRMs 51.02. Capital base from RFMs – Total capital base roll forward – Interim closing capital base where available, and otherwise, annual RINs – F10.1 Capital base values.

Note: AER calculation to convert capital base into $2022.

Capital base growth also contributes to higher forecast depreciation, which we discuss in the next section. Scheme pipeline expenditure and investment are analysed further in section 3.2.

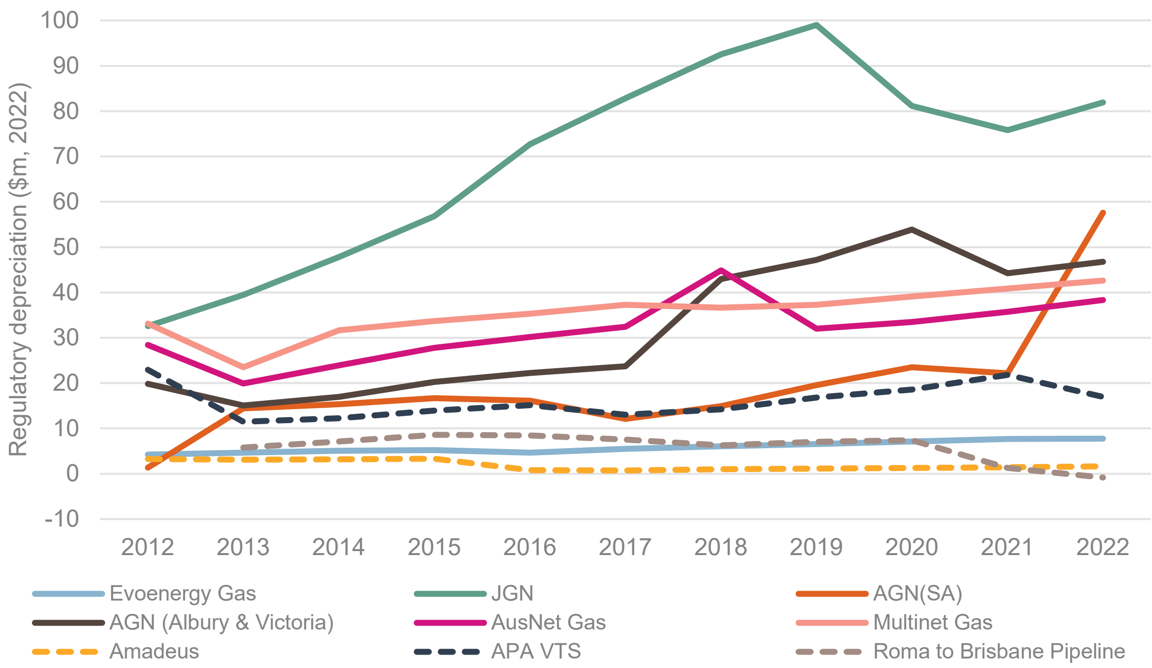
Increasing forecast revenue from growth in forecast depreciation

When investments are added to the capital base, they begin to gradually depreciate over their economic lives. Pursuant to the regulatory framework, we approve forecast regulatory depreciation for our access arrangement decisions.[31] This ensures that over the full economic lives of the assets, scheme pipelines recover revenue equal to the value of the investments.

The amount of depreciation recovered (via revenue) over an access arrangement period depends on the type of assets being invested in and the economic life of the assets. For example, mains replacements or new pipeline mains typically provide services over a long time (at least 50 years) and therefore typically have long economic lives. In contrast, expenditure on ICT is depreciated or amortised over a shorter period as ICT investments are more prone to being technologically superseded or determined obsolete.

Figure 3-6 illustrates forecast regulatory depreciation for scheme pipelines over 2012–2022.

Figure 3-6 Growth in the forecast depreciation building block – scheme pipelines



Source: PTRM 53.01 – Revenue summary Building block components – Return of capital and depreciation.

Note: Transmission scheme pipelines shown with dashed lines. AER calculation to convert into $2022.

Capital base growth has increased the amount of forecast depreciation across all distribution scheme pipelines. Forecast depreciation changes in response to the level of capital investment across different asset classes or changes in depreciation profiles, for example:

31 The *regulatory depreciation* approach involves two components, the depreciation of the asset value (straight-line depreciation consistent with the assets economic life) and the offsetting adjustment for indexation of the capital base. When we refer to *depreciation* it should be interpreted as the depreciation of the asset value prior to the offsetting adjustment for indexation of the capital base.

- The National Gas Rules enable us to accelerate depreciation where necessary to allow cost recovery and generate efficient prices as new information becomes available.[32] The large increase in AGN (SA)'s forecast depreciation in 2022 reflects our decision to accelerate depreciation for mains and inlet assets.[33] See the break-out box below on 'accelerated depreciation'.
- There can be large expenditure on assets with relatively short economic lives. The large increase in JGN's forecast depreciation over 2012–2019 reflected its program of expenditure on ICT software (approximately $135 million in 2020 dollars). ICT software has an economic life of only 5 years, so this investment rapidly increased forecast depreciation.

Despite transmission scheme pipelines being comprised of largely long-lived assets, their forecast depreciation is generally less smooth than what we observe for distribution. This likely reflects that they have smaller and therefore less diverse portfolios of physical assets, such that we see large changes to their metrics whenever they make a large investment[34], or an asset fully depreciates. For example, RBP's forecast depreciation started rising after its large capex program in 2012, which was also reflected in its capital base. Its capex was relatively moderate afterwards, which likely contributed towards its subsequently steady or declining forecast depreciation. RBP's forecast depreciation notably decreased in 2021 after two asset classes fully depreciated.[35] Historically, downward variation of depreciation profiles has been influenced by legacy asset categorisations with lower remaining lives approved during earlier periods of regulation.

Accelerated depreciation

Accelerated depreciation entails bringing forward the recovery of assets in the capital base, which occurs through the forecast depreciation building block. Forecast depreciation typically changes gradually because scheme pipelines are comprised largely of long-lived assets, although accelerated depreciation can speed this up. The effect of this is that costs to consumers increase in the short term, but the pool of depreciation to be recovered from consumers in the longer term reduces.

Accelerating the rate at which assets are depreciated may be necessary given the uncertainty of gas demand in a low carbon future.[36] It may be prudent to manage the equitable recovery of the cost of the assets where:

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32 Accelerated depreciation is discussed in AER, *Regulating gas pipelines under uncertainty: Information paper*, November 2021, pp. 28–32.

33 We approved 245.1 million ($2020-21) of accelerated depreciation in AER, *Final decision -AGN(SA) access arrangement 2021–26 – Attachment 4 – Regulatory depreciation*, April 2021, p. 8.

34 Lumpy investments associated with step changes in capacity such as pipelines and compressor facilities form a large proportion of the transmission capital base

35 These asset classes included the PMA and redundant compressors. See AER, *Final decision PTRM [RBP 2017–2022]*, November 2017, 'Assets' sheet; AER, *Final decision: RBP access arrangement 2017 to 2022, Attachment 5 – Regulatory depreciation*, November 2017, p. 5-6.

36 For a detailed discussion on the role of accelerated depreciation in light of the uncertain nature of gas pipelines, see AER, *Information paper – Regulating gas pipelines under uncertainty*, 2021, pp. 28–32.

- the consumer base faces incentives to transition to alternative sources of energy. This will need to consider how we best support consumers least able to respond to incentives.
- In the future gas networks and pipelines could potentially deliver renewable gas sources such as hydrogen or biomethane or a blend of renewable and natural gas.[37]

We recently approved accelerated depreciation in our recent access arrangement decisions for the Victorian scheme pipelines. In these decisions, we also sought to strike a balance between determining an appropriate level of accelerated depreciation and the impact it will have on price stability. For example, we only allowed a proportion of the accelerated depreciation sought by some of the Victorian distribution scheme pipelines to balance the price impacts in the short term with the need for longer term price stability.

3.1.5 Demand and differences in forecast and actual revenue

In this section, we look at how actual revenue has diverged from forecasts, and how this relates to actual demand differing from forecasts.

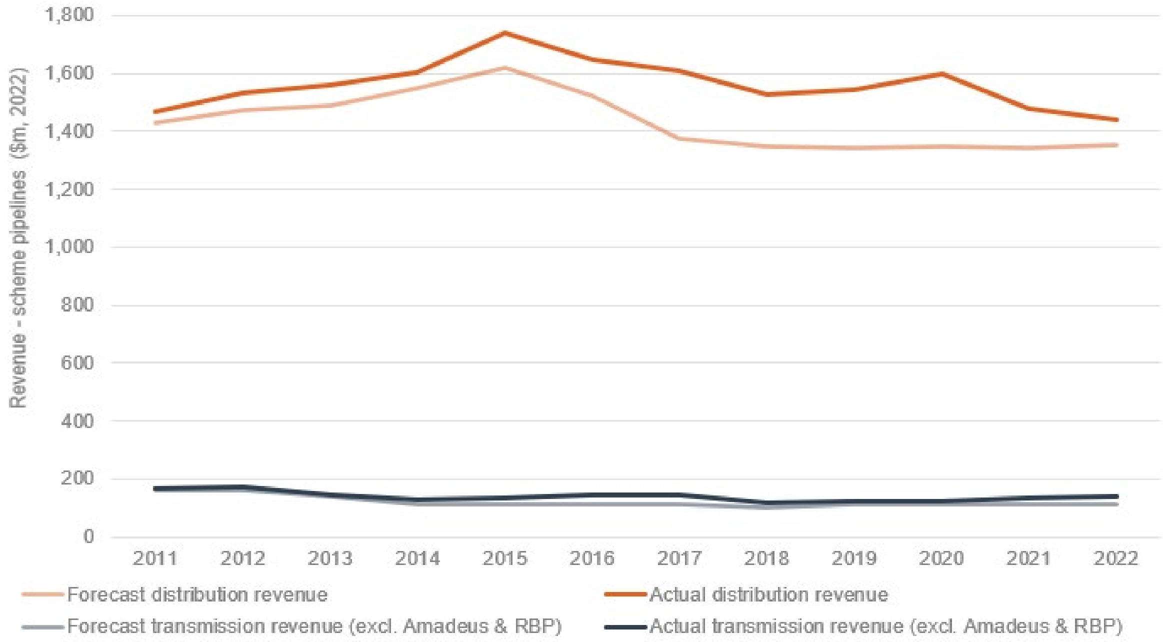
Demand for reference services is a key driver of the revenue that scheme pipelines collect. Under price caps, scheme pipelines are exposed to demand or 'volume-risk'. If demand exceeds forecasts, the scheme pipeline keeps the higher resulting revenue. Similarly, if demand is less than forecast, the scheme pipeline is exposed to the shortfalls. This incentivises scheme pipelines to develop tariff structures and undertake other activities that encourage network utilisation. This also means that demand forecasting error may contribute to scheme pipeline recovering more revenue from consumers, or scheme pipelines recovering less revenue than is necessary to efficiently provide reference services.

In the case of demand being higher than forecast, this should translate into higher forecast demand in the next period all other things being equal. However, all other things may not be equal. For instance, if a new government policy is expected to depress demand growth, demand forecasts may reduce even after a period of demand outperformance (see breakout box in Section 3.1.3). Price caps are designed to encourage scheme pipelines to grow demand, recognising that this growth should produce benefits that are shared by consumers through paying lower unit costs for reference services. This is particularly the case since reference services have high fixed costs and relatively low variable costs.

- Since 2011, scheme pipelines in aggregate have consistently recovered more revenue than forecast.
- The difference between forecast and actual revenue has generally grown larger over the time series (starting in 2011). However, after reaching a peak in 2020, this difference has been narrowing over the last 2 years for distribution scheme pipelines.

37 ENA, *Gas Vision 2050 – Delivering the pathway to net zero for Australia – 2022 Outlook*, April 2022.

Figure 3-7 Reference service revenue compared to forecast revenue



Source: Annual RINs – F3.1 Reference services (reference services revenue) and PTRMs – Revenue summary – Building block components (forecast revenue).

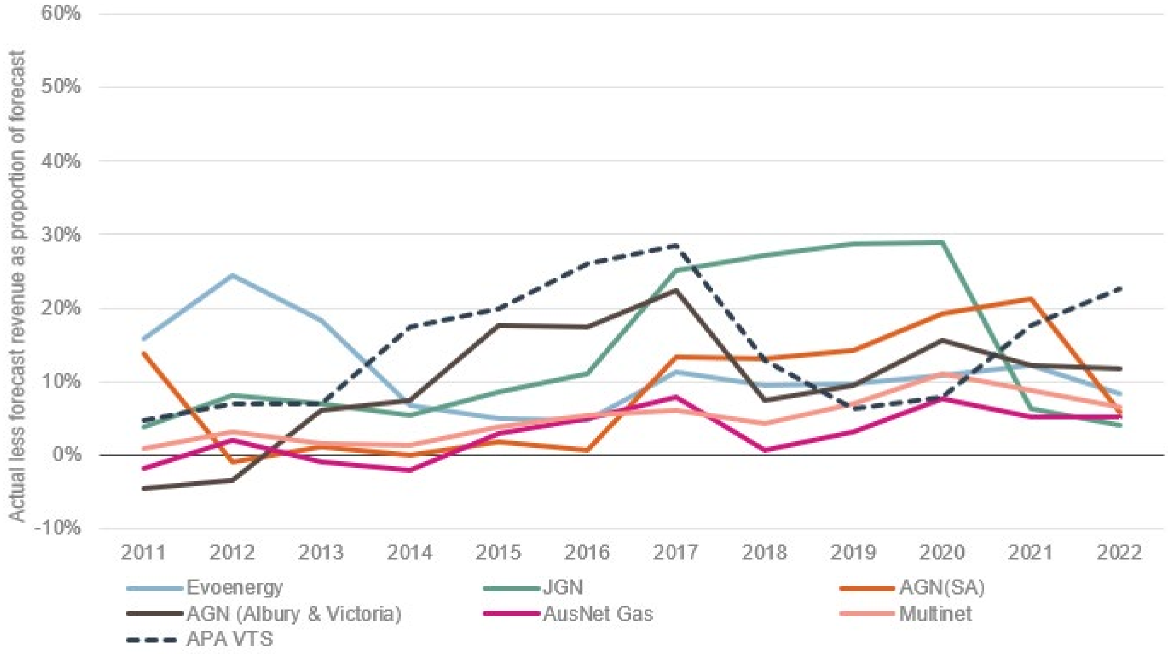
Notes: AER calculation to convert into $2022 terms using actual inflation measured by the consumer price index (forecast inflation is first stripped out from target revenue to present both series on like-for-like terms). Transmission scheme pipeline revenue excludes Amadeus and RBP due to confidentiality.

Distribution scheme pipelines on average consistently recovered more revenue than forecast. The margin of revenue outperformance was visibly greater over 2017–2020. This was partly influenced by JGN recovering additional revenue during its remittal process. Since 2019 JGN has been returning this revenue to consumers.[38] If we were to adjust for this impact, revenue outperformance on a distribution scheme pipeline average would still be greater than previous years, although the margin of over-recovery would narrow.

Figure 3-8 shows revenue outperformance as a proportion of forecast revenue. We express these differences as percentages, which are positive when actual revenue exceeded the forecast by that proportion.

[38] AER, *Final decision – Jemena Gas Networks (JGN) Adjustment determination*, February 2019.

Figure 3-8 Actual revenue[39] compared to forecast revenue – scheme pipelines



Source: Annual RINs – F3.1 Reference services (reference services revenue) and PTRMs – Revenue summary – Building block components (forecast revenue).

Note: JGN's revenue outperformance from 2015-16 is materially influenced the application of enforceable undertakings pending the outcome of limited merits review appeal process. AER calculations to convert into $2023 terms and to calculate percentage change (revenue less forecast revenue divided by forecast revenue).

Revenue effects affected transmission scheme pipelines more than they affected distribution. There are several plausible reasons for this relationship, including transmission scheme pipelines predominantly transporting gas to a small number of large consumers. This feature of transmission could make forecasting demand more challenging and creates greater scope for transmission scheme pipelines to structure tariffs to stimulate demand by providing non-reference services.

Differences in actual and forecast revenue are a function of actual demand, forecast demand and how tariffs change throughout the access arrangement period (within approved tariff variation mechanisms). As such, actual and forecast demand may differ because of:

- Unforeseen market changes, such as changes in gas consumption patterns following an unforeseen event like the COVID-19 pandemic. In such a scenario, the original demand forecasts on which the access arrangement determination is based may still reflect the best forecasts possible with the information available at the time.
- Shortcomings in demand forecasting. Forecasting can be challenging and requires forecasting multiple interrelated variables, including but not limited to weather conditions,

39 Actual revenue presented is limited to reference service revenue for distribution but can include other revenue for transmission. This is because transmission scheme pipelines may enter long term contracts where the negotiated contract terms and conditions, including price, may not correspond directly to the reference services in the access arrangement. .

wholesale prices, appliance efficiency and consumer sentiment. Moreover, regulation under price caps creates an incentive to forecast lower demand. A greater divergence between forecast and actual revenue later in each access arrangement period may reflect that it is increasingly difficult to forecast events that are further out. This is evident in some of the forecasts, such as the lower outperformance experienced by VTS in 2019 (which was the first year of an access arrangement period).

- The effect of scheme pipelines re-balancing or varying tariffs within 'side-constraints'. This re-balancing can impact overall revenue recovery relative to forecast. Scheme pipelines may choose to re-balance tariffs with a view to increase demand. We would expect increased demand to be reflected in the following period's demand forecasts, thereby lowering prices for future periods. If scheme pipelines recover more revenue than forecast because they are actively responding to incentives to stimulate demand, outperformance could indicate lower future prices for reference services.

Understanding the interaction between demand forecasts, actual demand and revenue is important in evaluating the effectiveness of our regulatory decisions and approaches. This interaction is complex and varies between scheme pipelines and tariffs. However, we consider differences in forecast and actual revenue provide a useful overall indicator of the impacts of unexpected changes in demand. For an example of how the various factors affecting revenue can interact, see our 2022 gas network performance report.[40]

3.2 Expenditure

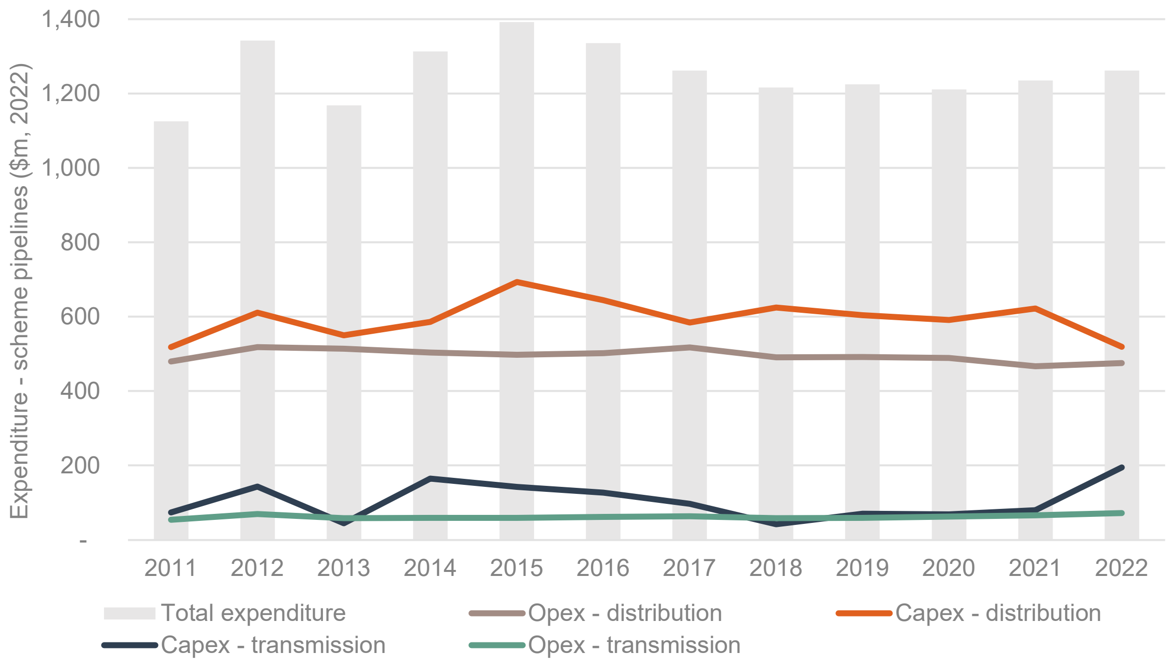
With the revenue collected from consumers, scheme pipelines undertake opex and capex however they determine to be most efficient in providing reference services safely and reliably. In this section, we report on capex and opex trends. We focus particularly on capex, which has more distinct variation across scheme pipelines.

40 AER, *Gas network performance report*, 2022, p. 39.

- In 2022, total expenditure decreased by 8.7% for distribution scheme pipelines compared to 2021. This decrease was driven by a 16.6% decrease in capex, resulting in total distribution expenditure falling to its previous low of $997 million last reached in 2011.
- In 2022, total expenditure increased by 83% for transmission scheme pipelines compared to 2021. This increase was driven by a 144% increase in capex, resulting in total transmission expenditure reaching its highest level over the measurement period (commencing 2011). Most of this increase was driven by APA VTS's expansion capex, which increased from $23.3 million to $130.7 million between 2021 and 2022.
- Opex has remained relatively steady for scheme pipelines, with most year-to-year variation driven by capex. Capex is particularly variable for transmission scheme pipelines.
- Given the recurrent and predictable nature of opex, we generally find that scheme pipelines incur a similar amount of opex to what we forecast. However, since 2018, distribution scheme pipelines have been increasingly spending less opex than forecast.
- Actual and forecast capex is more variable than opex. We observe a mixture of aggregate capex overspends and underspends for scheme pipelines, with more underspends at the distribution-level and more overspends at the transmission-level.

Figure 3-9 shows scheme pipelines' total expenditure over 2011 to 2022, disaggregated by opex/capex and distribution/transmission. Total expenditure amongst scheme pipelines reached a peak of $1.39 billion in 2015 and was $1.26 billion in 2022.

Figure 3-9 Network expenditure



Source: Opex: RINs – F4.1 Opex by purpose. Capex: RFMs – RFM input – Actual capital expenditure, 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.

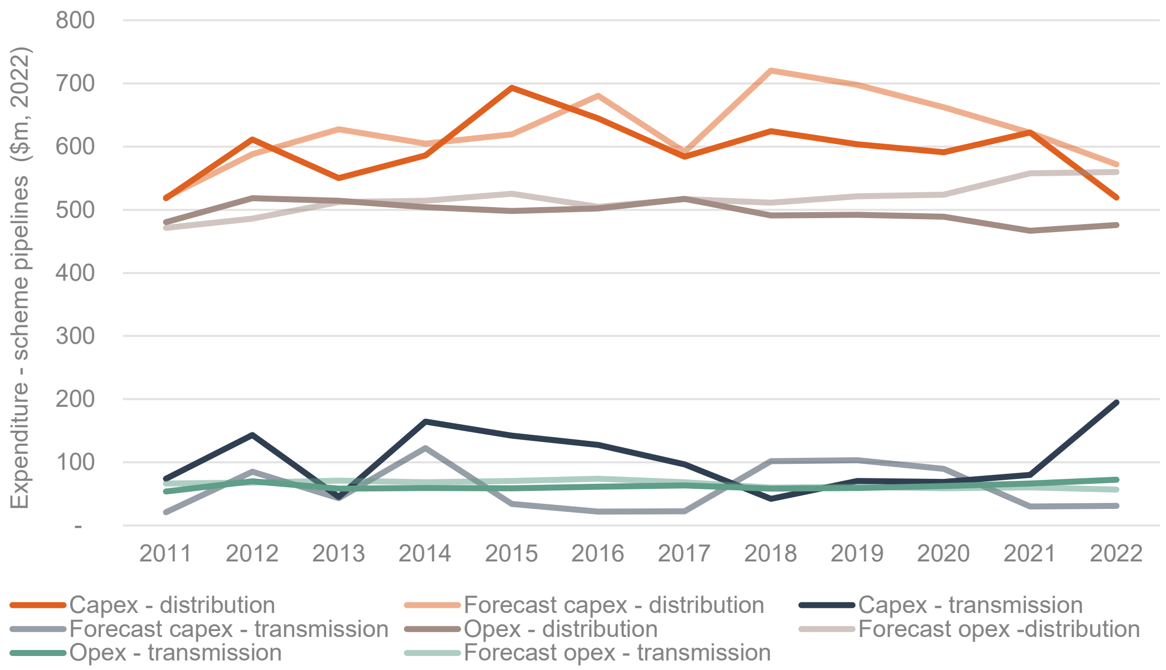
Note: AER calculations to convert into $2022 and to calculate net capex (gross capex minus capital contributions minus disposals).

We observe that transmission scheme pipelines' opex has been steady compared to capex which varied considerably. In 2022, transmission capex increased 144% on 2021 levels to reach $195 million, exceeding the previous peak of $165 million in 2014. The main driver the increase was APA VTS's expansion capex, which increased from $23.3 million in 2021 to $130.7 million in 2022.[41]

It is not unprecedented for transmission scheme pipelines to experience large annual variation in expenditure relative to distribution given the small size of two of the transmission scheme pipelines which contributes to lumpy capex profiles.

Figure 3-10 compares total opex and capex outcomes against our forecasts for distribution and transmission scheme pipelines.

Figure 3-10 Comparison of actual and forecast expenditure



Source: Opex: annual RINs – F4.1 Opex by purpose. Capex: RFMs – RFM input – Actual capital expenditure, 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. Forecasts: PTRMs – PTRM Input – Forecast operating and maintenance expenditure and forecast net capital expenditure.

Note: AER calculations to convert into $2022 and to calculate net capex (gross capex minus capital contributions minus disposals).

Figure 3-10 illustrates that while capex is more variable than opex, distribution scheme pipelines underspending of forecast opex allowances has increased. There are several drivers of this divergence, the largest of which are the following:

- Around half of the opex underspend in 2021 and 2022 was driven by JGN, which shifted from having a small overspend in 2020 to spending around 20% less than forecast in

41 AER, *Final decision – APA VTS access arrangement 2023–2027 | Attachment 5 – Capital expenditure*, December 2022, p. 6.

2021 and 2022. JGN's underspend is of a larger magnitude relative to the other scheme pipelines who underspent forecast opex in similar proportions, due to the size of its allowance. JGN submitted that its opex reductions stemmed from implementing an organisational structure change in 2021 that optimised and rationalised its business functions. This included contracting some of JGN's work activities to a service provider owned by its parent company.[42]

- Multinet Gas's opex underspend was around 20% of the total underspend in 2021 and 2022. Multinet Gas spent around 20% less opex than forecast since 2018. It attributed these savings to entering a lower cost national operational and management services contract after being acquired and consolidated into the Australian Gas Infrastructure Group.[43]
- AGN (SA)'s opex underspend was also around 20% of the total underspend in 2021 and 2022. AGN (SA) has spent around 20% less opex than forecast since 2019. In 2022, it attributed these savings to: (1) lower repairs and maintenance expenditure –particularly leaks, (2) lower UAFG, and (3) general business-wide efficiencies.[44] AGN (SA) also identified similar drivers in previous years.[45] In our view, opex savings due to lower UAFG costs and leaks-related maintenance are expected outcomes of AGN (SA) undertaking a major mains replacement program.

Figure 3-11 and Figure 3-12 in the next section illustrate how the difference between actual and forecast capex varies materially between scheme pipelines and years. These outcomes may reflect factors such as the lumpiness of capex, expenditure management within the access arrangement period cycle, and scheme pipelines' expenditure incentives.

3.2.1 Transmission expenditure

Figure 3-11 below shows that the three transmission scheme pipelines often incur materially more capex than forecast. Transmission scheme pipelines operate fewer assets compared to distribution networks. Transmission capex is less driven by connections, and a greater proportion is driven by meeting safety and integrity drivers. We observe that the profile of actual and forecast capex for each of the three transmission scheme pipelines is particularly lumpy and unique to each transmission scheme pipeline.

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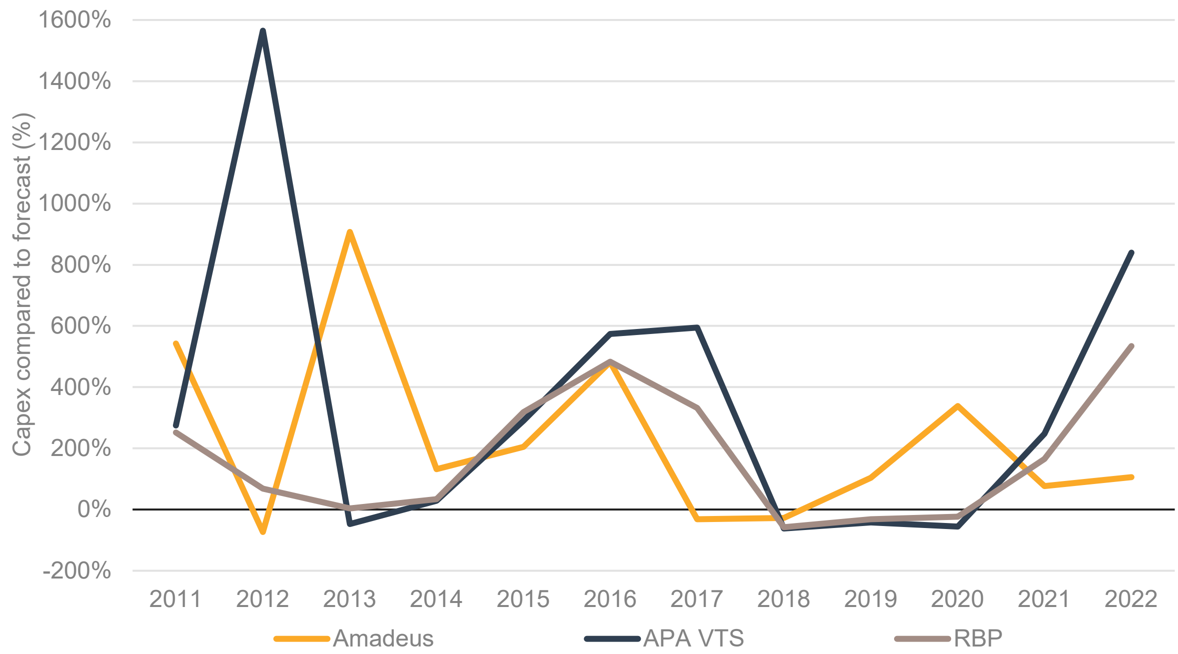
42 JGN transitioned to a contractional arrangement with Zinfra Pty Ltd, which is a wholly owned subsidiary of JGN's partner company, SGSP (Australia) Assets Pty Ltd. JGN, *2021-22 response to the annual reporting RIN – Written response – Schedule 1 – Attachment 1*, 30 November 2022, p. 3.

43 AER, *Draft decision – Multinet Gas Networks Access arrangement 2023 to 2028 – Attachment 6 – Operating expenditure*, December 2022, p. 14.

44 AGN (SA), Annual RIN basis of preparation, November 2022, p. 19.

45 For example, see AGN (SA), *Annual RIN basis of preparation (2019-20)*, November 2020, p. 20; AGN (SA), *Annual RIN basis of preparation (2011-2019)*, September 2020, p. 29.

Figure 3-11 Actual capex under (over) spend (%) relative to forecast – transmission



Source: Capex: RFMs – RFM input – Actual capital expenditure, 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. Forecast capex: PTRMs – PTRM Input – Forecast net capital expenditure.

Note: AER calculations to convert into $2022, calculate net capex (gross capex minus capital contributions minus disposals) and to calculate the comparison as (capex – forecast capex) ÷ forecast capex.

Figure 3-11 shows that APA VTS's capex in 2022 was materially ($140.2 million) higher than forecast. APA VTS explained this divergence in its basis of preparation as mainly being attributable to two projects:[46]

- 70% of the variance resulted from $98.7 million in capex on the Western Outer Ring Main project. This project was forecast to occur earlier on in the access arrangement period but was deferred pending the outcome of a required Environmental Effects Study.
- 19% of the variance resulted from $26.4 million in capex to install a second unit at the Winchelsea compressor station, which had not been forecast.

This example illustrates how a delay in one gas transmission project can materially affect the scheme pipeline performance against a capex forecast.

Recognising the uniqueness of each transmission scheme pipeline's capex profile, we closely examined why forecast and actual capex varied over time for each transmission scheme pipeline in our 2022 gas network performance report.[47] In performing this analysis, we found that previous AER access arrangement decisions indicated that higher actual expenditure than forecast was predominately driven by transmission scheme pipelines

46 APA, *VTS annual RIN reporting: RIN response and basis of preparation for year end 31 December 2022*, May 2023, pp. 25–26.

47 AER, [Gas network performance report](), December 2022, pp. 46-49.

incurring unexpected expenditure rather than the AER approving materially less capex than proposed.

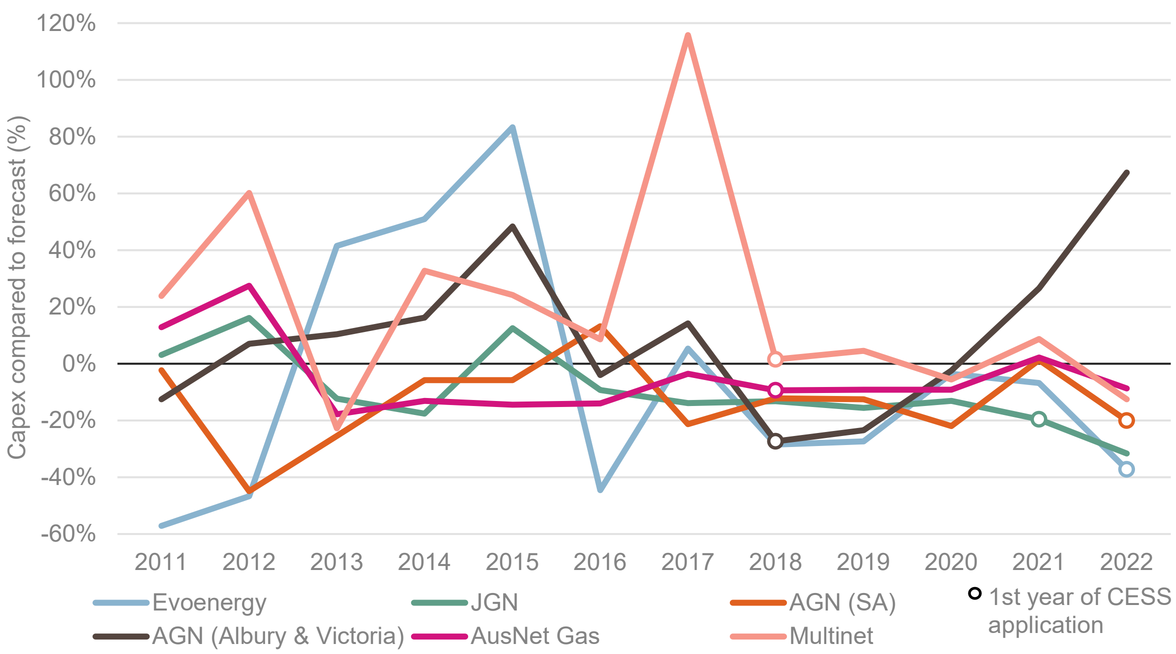
It is important to recognise that while incurring substantially more capex than forecast would have a negative impact on profitability, this negative effect seems to be mitigated or offset in practice. Transmission scheme pipelines have been able to profitably provide reference services despite often incurring more capex than forecast. For instance:

- As a mitigating factor, if the AER deems previous overspends as 'conforming capex' under Rule 79(1) of the National Gas Rules (that is, assesses the capex as prudent and efficient), this expenditure still enters the capital base where the scheme pipeline earns a depreciation allowance and return on capital.
- As an offsetting factor, lower forecast expenditure would in part reflect the expectation that scheme pipelines would be servicing the forecast level of demand. Demand for reference services has been higher than forecast, with higher demand creating costs associated with connections, capex and opex. As scheme pipelines are exposed to demand risk, they are incentivised to increase demand where the revenue they receive from doing so is higher than the costs they will incur from servicing that demand. This appears to have been the case for transmission scheme pipelines.

3.2.2 Distribution expenditure

Figure 3-12 illustrates the difference between actual and forecast capex incurred by individual distribution scheme pipelines.

Figure 3-12 Actual capex under (over) spend (%) relative to forecast – distribution



Source: Capex: RFMs – RFM input – Actual capital expenditure, 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. Forecast capex: PTRMs – PTRM Input – Forecast net capital expenditure.

Note: AER calculations to convert into $2022, calculate net capex (gross capex minus capital contributions minus disposals) and to calculate the comparison as (capex – forecast capex) ÷ forecast capex.

The white markers in Figure 3-12 identify the first year when the CESS was applied to that scheme pipeline.

In last year's report, we suggested gas capex outcomes may also in part reflect the operation of incentive schemes. While we have applied opex efficiency schemes to distribution scheme pipelines since 2010, we only started to apply a capex sharing scheme (CESS) from 1 January 2018 – starting with the Victorian distribution scheme pipelines. Our intention of introducing a CESS to distribution scheme pipelines is that it would provide the benefits of efficient capex by:[48]

- Smoothing capex incentives throughout the access arrangement period.
- Placing downward pressure on capital base growth.
- Addressing the imbalance in incentives between undertaking capex or opex, particularly toward the end of the access arrangement period.

While we consider it too early to assess the impact of the CESS on distribution scheme pipelines, we intend to monitor this impact in future reports.

In contrast to transmission, distribution scheme pipelines report on capex by purpose as defined in Table 3-1. This data allows us to explore the differences between distribution scheme pipelines more systematically.

Table 3-1 Capital expenditure purpose and definition

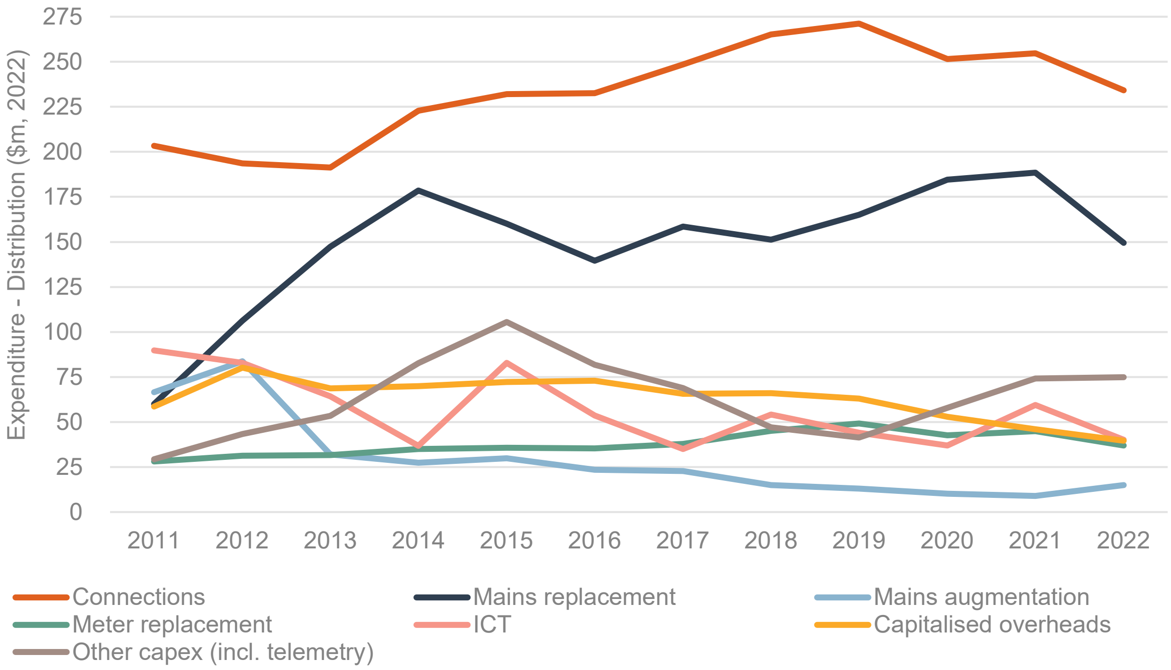
Capex purpose	Definition
Connections	Capex related to connecting new customers to the scheme pipeline.
Mains replacement	Capex related to replacing the existing mains and services due to their condition.
Mains augmentation	Capex related to a change in the capacity requirements of mains and services to meet the demands of existing and future customers
Telemetry	Capex related to a replacement of SCADA due to the condition of the assets.
Meter replacement	Capex related to replacing installed meters with new or refurbished meters.
ICT	Capex related to ICT assets but excluding all costs associated with SCADA that exist beyond gateway devices (routers, bridges etc.) at corporate offices
Capitalised Overheads	Corporate or network overheads which are capitalised as part of the network asset.
Other	Capex which is not related to any other capex purpose, including and non-operational buildings.

48 AER, *Draft decision – AGN Victoria and Albury access arrangement decision 2018 to 2022 – Attachment 14*, 2017, p 10; AER, *Draft decision – AusNet Gas access arrangement decision 2018 to 2022 – Attachment 14*, 2017, p 10; AER, *Final decision – Multinet Gas access arrangement decision 2018 to 2022*, 2017, p 6.

Over 2011 to 2022, connections expenditure (driven by customer demand) and mains replacement expenditure (driven by safety) were a considerable proportion of the investments that distribution scheme pipelines made. Expenditure on both these items decreased in 2022 relative to 2021.

Figure 3-13 sets out capex by purpose combined across all the distribution scheme pipelines. The capex categories of connections and mains replacement are the main capex drivers, adding new long-lived assets to the capital base. Growth in customer numbers drove much of the capex on connections and meeting safety and reliability requirements drove much of the replacement capex. [49] While mains replacement capex has been high, mains augmentation capex has decreased over the period, illustrating that most gas capex is spent on safely maintaining the existing network.

Figure 3-13 Capital expenditure by purpose – distribution scheme pipelines



Source: Annual RINs – E1.1.1 Reference Services.

Note: AER calculation into $2022 terms. Telemetry expenditure is added to other capex as it is low (consistently <$5m). Capitalised overheads include capitalised corporate overheads and capitalised network overheads.

Figure 3-14 demonstrates the notable variation across distribution scheme pipelines in the average proportion of actual capex incurred for each of the categories in 2022.

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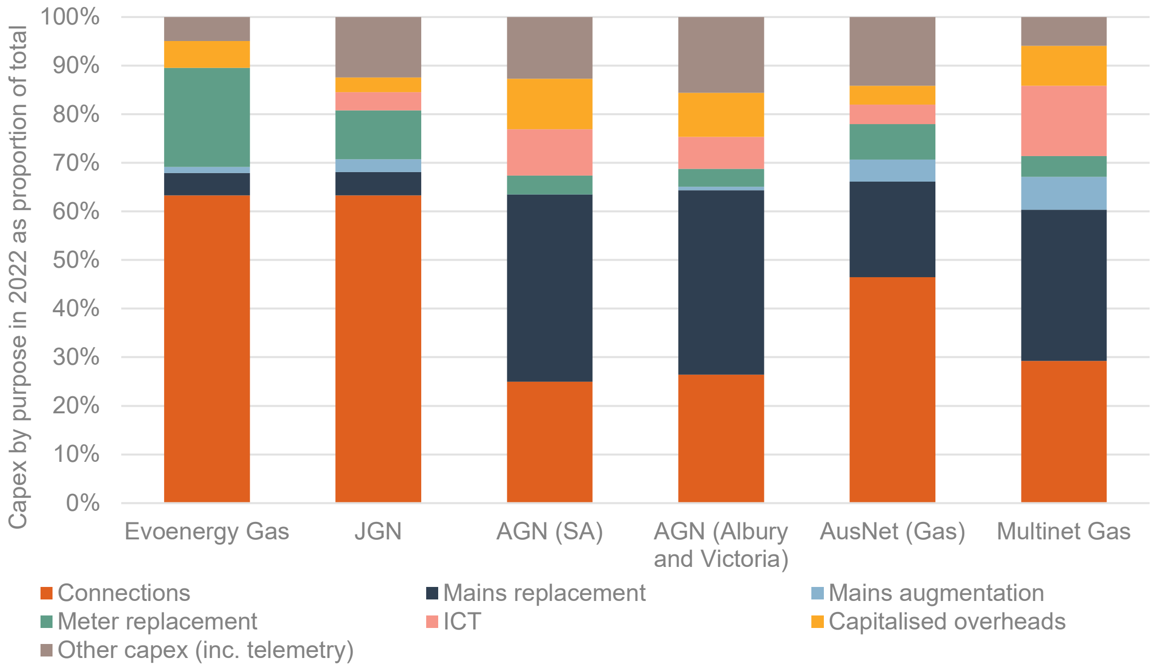
49 ESCV, *Review of Gas access arrangements final decision,* 2002, p. 117.

Figure 3-14 Capex by purpose as proportion of total in 2022 – distribution



Source: Annual RINs – E1.1.1 Reference Services. AER calculations to convert into $2021 terms and to calculate capex categories as a proportion of each distribution scheme pipeline's total capex.

Figure 3-14 shows that a substantial proportion of capex is on mains replacement in Victoria and South Australia. This reflects that the Victorian and South Australian distribution scheme pipelines were still undertaking substantial mains replacement programs in 2022.

Mains replacement programs

Mains replacement programs commenced for the Victorian gas distribution scheme pipelines in their 2003–2007 access arrangement period and aimed to progressively replace the aging cast iron pipelines to meet safety and reliability requirements.[50] AGN (SA)'s cast iron replacement program also sought to reduce the risk of losses from gas leaks and increase both the capacity and reliability of the gas networks. Alongside these benefits, the replacement programs were also expected to improve the UAFG for these gas distribution scheme pipelines,[51] reducing the gas loss caused by the deteriorating cast iron pipes.

JGN and Evoenergy Gas have not recently undertaken mains replacement programs targeting low-pressure cast iron pipes. JGN's cast iron replacement program in the 1990s reduced the amount of cast iron in their network to less than 1%,[52] and we have no reports of Evoenergy Gas having had any cast iron mains.

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50 AER, _Multinet Gas – Draft Decision – 2013 to 2017 access arrangement_, 2012, pp. 32–33; ESCV, *Review of Gas access arrangements final decision,* 2002, p. 117.

51 ESCV, _Review of unaccounted for gas benchmarks: final decision – calculation_, 2017, p. 5.

52 JGN, _JGN – 2021 to 2026 access arrangement revised proposal – Attachment 8.5_, 2019, p. i.

AGN (Albury and Victoria) completed its program in the 2018–2022 access arrangement period, although still requires some ongoing mains replacement capex to meet safety and reliability standards.[53]

Low pressure replacement programs for the other distribution scheme pipelines are still ongoing and have influenced capex allowances in the current access arrangements.[54]

3.3 Capital bases

The scheme pipelines' capital bases capture the total economic value of assets providing reference services to consumers. The stock of assets accumulated over time and will be at various stages of their economic lives. A scheme pipeline's assets may be relatively old or new, depending on its growth and where it is in the replacement cycle.

The value of the capital base has a significant impact on scheme pipelines' revenue requirements, and the total costs consumers ultimately pay for reference services.

- Since 2011, the total value of capital base for scheme pipelines has grown by approximately 21% (18% for distribution and 38% for transmission). Victoria and South Australia have experienced the highest capital base growth across all jurisdictions.
- Capital intensiveness (measured as capital base per customer or per volumes of gas delivered) of most distribution scheme pipelines has remained relatively stable due to growth in customer numbers. An exception to this is AGN (SA), which is the most capital-intensive network and this margin widened with its mains replacement program.
- In 2022, the aggregate value of all capital bases was a similar real value than in 2021. The 8.24% increase in transmission capital bases offset the 1.24% decrease in distribution capital bases.

Figure 3-15 sets out the capital bases for scheme pipelines. Distribution capital bases gradually increased from 2011 and have reduced over the last 2 years after reaching a peak in 2020.

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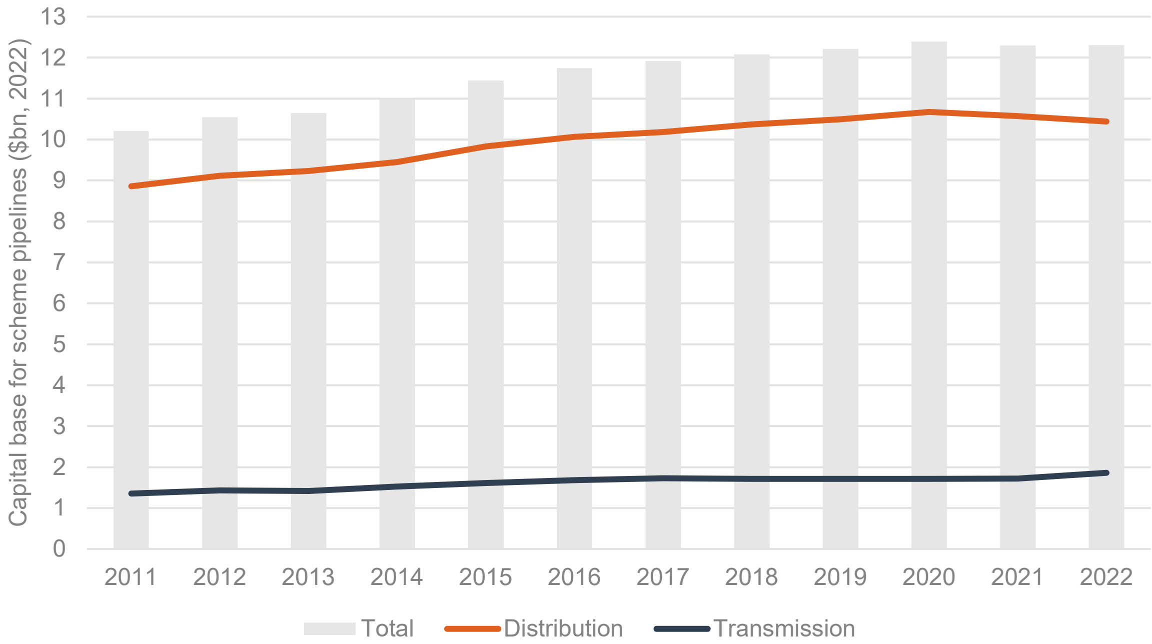
53 AGN (Albury & Victoria), *Final plan: Access arrangement information 2018-2022*, December 2016, p. 83; AER, *Final decision: AGN (Victoria & Albury) gas distribution access arrangement 1 July 2023 to 30 June 2028 – Attachment 5 – Capital expenditure*, June 2023, pp. 6–7

54 AER, *Final decision: Ausnet Gas Services gas distribution access arrangement 1 July 2023 to 30 June 2028 – Attachment 5 – Capital expenditure*, June 2023, p. 6; AER, *Final decision: AGN (SA) gas distribution access arrangement 1 July 2023 to 30 June 2028 – Attachment 5 – Capital expenditure*, April 2021, p. 6; AER, *Final decision: Multinet Gas Networks gas distribution access arrangement 1 July 2023 to 30 June 2028 – Attachment 5 – Capital expenditure*, June 2023, p. 6.

Figure 3-15 Capital base for scheme pipelines



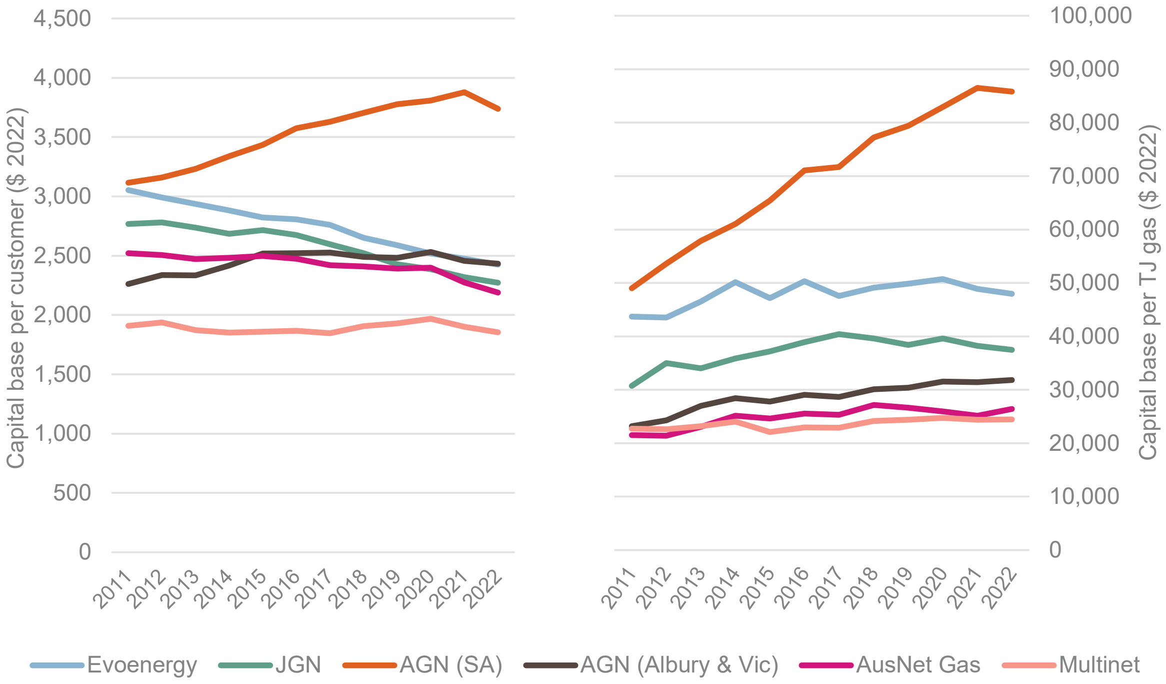
Source: RFMs – Total capital base roll forward – Interim closing capital base, or where unavailable in an RFM, annual RINs – F10.1 Capital base values.

Note: AER calculation to convert into $2022 terms.

A stable capital base may allow declining real capital costs per customer if the customer base is growing. This effect is amplified where required rates of return are declining, as observed earlier (see Figure 3-5).

Figure 3-16 shows the distribution capital base per customer alongside the capital base per volume of gas delivered. Capital base per customer is a useful indicator of the average value of capital employed per customer but is also sensitive to the composition of the customer base. For example, holding other things constant, we might expect a scheme pipeline to have more capital invested per customer than other pipelines if a higher proportion of its gas were delivered to industrial customers. In contrast, capital base per volume of gas delivered accounts for the different patterns of usage by different customer types and is therefore less sensitive to the composition of the customer base.

Figure 3-16 Capital base per customer / Capital base per gas delivered – distribution



Source: Capital base: RFMs – Total capital base roll forward – Interim closing capital base, or where unavailable in an RFM, annual RINs – F10.1 Capital base values. Customer numbers: annual RINs – S1.1 Customer numbers by customer type. Gas delivered: annual RINs – N1.1 Demand by customer type.

Note: AER calculation to convert into $2022 terms and to divide the capital base for each distribution scheme pipeline by that pipeline's (a) customer numbers and (b) gas delivered.

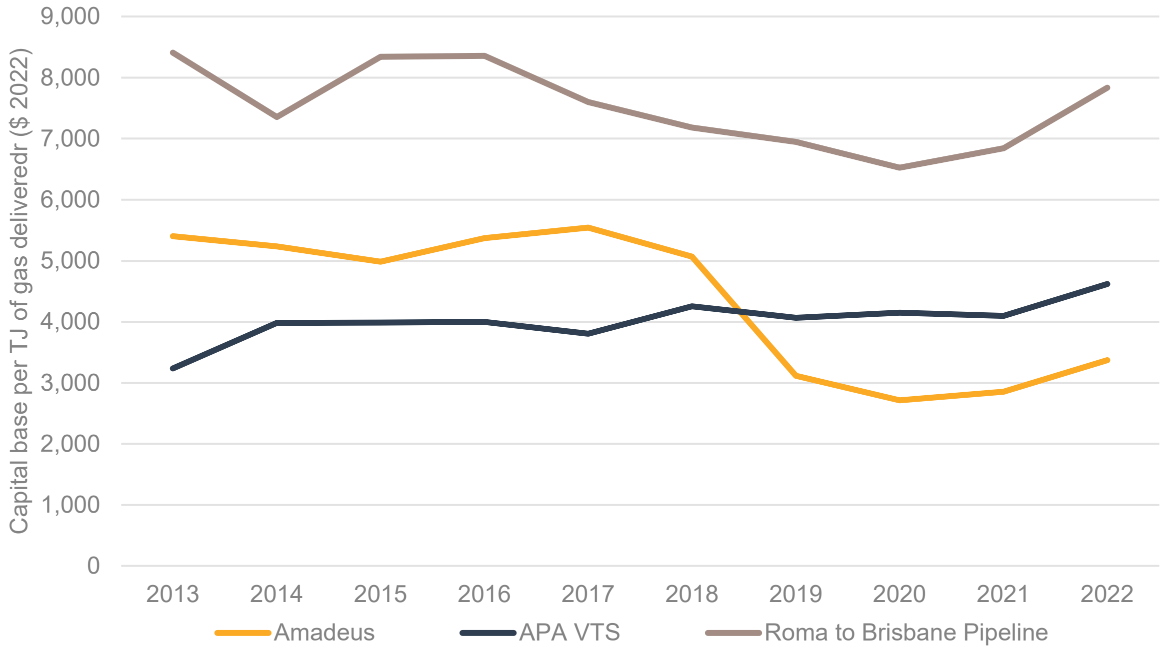
We observe distribution scheme pipelines experience steady to declining capital base per customer metrics, outside of South Australia, reflecting growth in distribution customers. In contrast, we observe steady to increasing capital bases per gas delivered amongst these pipelines reflecting a gradual decline in gas delivered by distribution scheme pipelines.

AGN (SA) stands out on both measures in Figure 3-16 because increases in its capital base were notably larger than growth in customer numbers and gas delivered. This result is due to AGN (SA)'s large mains replacement program, as forecast and included in its three latest access arrangement decisions.[55]

Since capital base per customer is less insightful and more difficult to interpret for transmission scheme pipelines, Figure 3-17 focusses only on capital base per volume of gas delivered for transmission.

55 AER, *Final decision: AGN (SA) access arrangement 2021–26, Attachment 5—Capital expenditure*, April 2021, p. 6.; AER, *Final decision: AGN access arrangement 2016 to 2021, Attachment 6—Capital expenditure*, May 2016, pp. 7-8.

Figure 3-17 Capital base per TJ of gas delivered – transmission



Source: Capital base: RFMs – Total capital base roll forward – Interim closing capital base, or where unavailable in an RFM, annual RINs – F10.1 Capital base values. Gas delivered from annual RINs – N1.1 Demand by customer type.

Note: AER calculation to convert into $2022 terms and to divide the capital base for each transmission scheme pipeline by their gas delivered.

In Figure 3-17, we see VTS's capital base per volume of gas delivered followed a similar steady upwards trend to the Victorian distribution scheme pipelines shown in Figure 3-16. However, this metric followed less of a steady trend for Amadeus and RBP, reflecting the less diverse customer base and lumpy capex profiles of those two scheme pipelines. The largest change to capital base per gas delivered was experienced by the Amadeus gas pipeline in 2019 when it started delivering gas via the Northern Gas Pipeline to the East Coast gas market. In 2020-21, the volume of gas delivered to the Northern Gas Pipeline was 48% of the total gas delivered via the Amadeus gas pipeline.[56]

In 2022, capital base per gas delivered increased on 2021 levels for all transmission scheme pipelines. This was driven by material decreases in gas volumes delivered for Amadeus (14%) and RBP (12%) and a 12% increase APA VTS's capital base following it undertaking two large capex augmentation projects (see section 3.2).

3.4 Distribution service outcomes

In this section, we report on the service outcomes that consumers receive from distribution scheme pipelines – gas delivered, network outages and UAFG. While there are other measures of service quality, network outages and UAFG are two measures that are readily quantifiable and reported annually for distribution.

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56 APA, *Annual RIN - Amadeus Gas Pipeline: RIN response and basis of preparation*, November 2021, p. 42.

Distribution scheme pipelines are inherently reliable, for reasons discussed further in this section. Over time, we intend to investigate whether we should expand our reporting to cover service outcomes for transmission or include other service outcomes for distribution that are important to consumers.

- Total gas deliveries reported in 2022 decreased by 1.9% from 2021. Gas delivered to residential and industrial customer decreased by 1.6% and 2.8% respectively. Commercial gas deliveries where steady at 0.05% increase after partial recovery from COVID response measures in 2021.
- While UAFG as a proportion of gas delivered increased from 3.2% to 3.4% between 2021 and 2022, it was still relatively low since reporting commenced from 2011.
- Variance across scheme pipelines in UAFG as a proportion of gas delivered has generally reduced since 2011. Most of this reduction was driven by AGN (SA) changing from having materially high levels of UAFG as a proportion of gas in 2011 (7.5%) to having the lowest levels in 2022 (1.9%)
- In 2022, total outages reached a low over the time series of less than 0.01 outages per customer – an equivalent to a customer experiencing an outage less than once every 100 years. This record low was driven by a 44% reduction in planned outages since 2021 despite planned outages already being lower in 2021 than any other year since 2011.

3.4.1 Gas delivered

Gas delivered is indicative of demand which is influenced by several external factors from consumer preferences to changes in government policies. We report on gas delivered by customer type to demonstrate the contribution of residential, commercial, and industrial customers to demand.

Government policy changes, pandemic responses, or unexpected weather events may cause exogenous demand shocks affecting gas usage of certain customer groups.[57] For example, homes connected to a gas distribution network mostly use gas for space heating during winter. The ENA's 2021 'Reliable and clean gas for Australian homes' report states that demand for gas in winter is more than four times that in summer.[58] Cooler (warmer) winters may increase (decrease) demand for gas heating. The pandemic response provides another example where we observed in 2020 gas delivered to commercial customers fell, and residential customer demand rose, especially in Victoria. In addition, gas delivered "by customer" shows how different customer types may be affected in the future by net-zero carbon policies. These policies aim restrict growth in new connections be they residential or business premises, while incentivising customers with an existing connection towards electrification.

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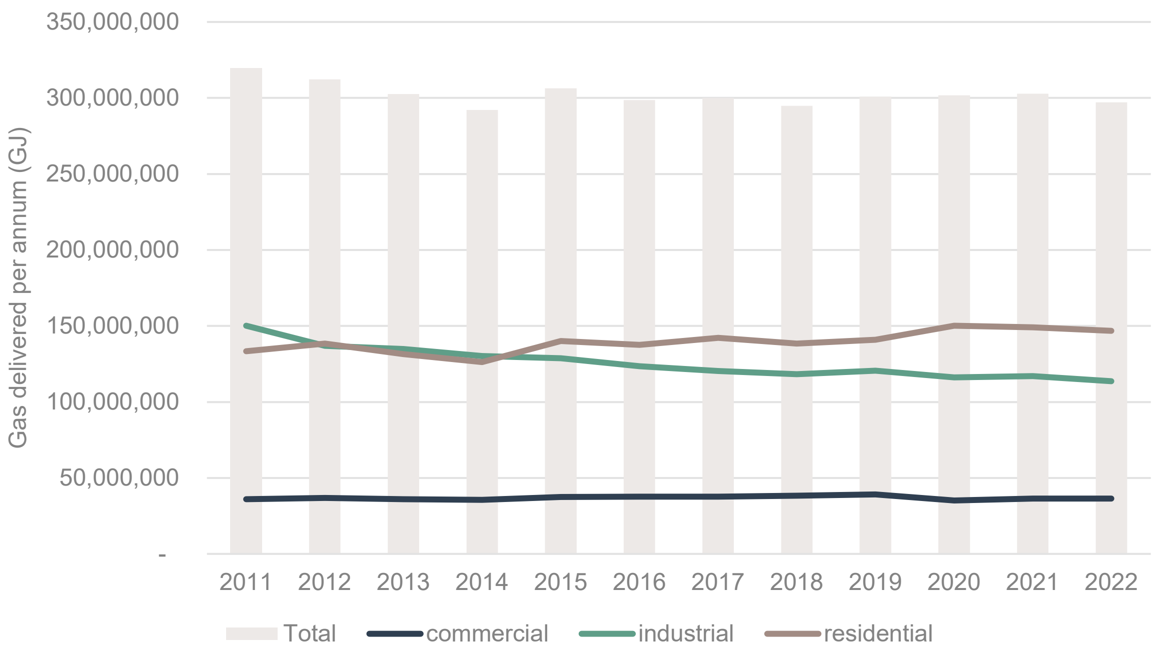
57 Exogenous shocks can be from changes in the environment or other events outside the control of consumers or service providers.

58 ENA, *Reliable and clean gas for Australian homes*, July 2021, p.4.

Figure 3-18 Total gas delivered and gas delivered by customer type - Distribution (GJ)



Source: Annual RINs Gas delivered – N1.1 Demand by customer type (Distribution).

Figure 3-18 shows distribution scheme pipeline gas deliveries across residential, commercial, and industrial customers declined by 1.87% in 2022. Table 3-2 presents the following observations on changes in the annual growth rate of gas delivered broken down by customer type.

Table 3-2 Gas delivered by customer type (GJ)

Customer type	Average annual growth rate (%)	5 year average (%)	2022 change from previous year (%)
Residential	0.9	1.2	-1.6
Commercial	0.1	-0.9	0.1
Industrial	-2.5	-0.8	-2.8
Total	-0.7	-0.2	-1.9

Source: AER analysis. Annual RIN reporting 2011 to 2022.

Note: Average annual growth rate is measured over the reporting period from 2011 to 2022 and the 5-year average is measured from 2018 to 2022.

More recent measures of annual variation in gas demand are affected more by the pandemic response. For instance, residential demand declined as business districts reopened and people returned to work on site. For commercial and industrial users annual change in 2022 appears to be returning closer to the long-run average.

The effect of policy developments toward net-zero on the future use of gas networks and gas demand is uncertain. Our recent decisions approved accelerated depreciation due to the uncertainty of future gas demand in Victoria.[59] In addition, AEMO's Gas statement of opportunities forecasts a decline in gas volumes over the next 20 years.[60] AEMO's 2023 GSOO forecasts residential and commercial consumption to decline by 61 per cent from 2022 to 2042.[61] AEMO forecasts consumption to decline due to lower connections (new buildings), and electrification of existing customers switching from gas to electricity for their energy needs.[62] It will be of interest to continue to monitor how customer numbers and gas consumption change over time and the use of gas networks evolves in the future.

3.4.2 Unaccounted for gas

UAFG is the difference between the measured quantity of gas entering the network (gas receipts) and metered gas deliveries (gas withdrawals). UAFG can have various causes, although these 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.[63] It is an important measure for consumers as they ultimately face its cost.

The extent to which different factors affect UAFG is uncertain and scheme pipelines have different degrees of control over these causes. [64] For example, distribution scheme pipelines have relatively high control over fugitive emissions, whereas heating value depends on the quality of gas injected into the network, which is largely outside their control.[65] Our previous analysis did not find a clear, general relationship between UAFG and mains leaks except in specific circumstances. For instance, the relationship between these variables appeared positive for AGN (SA) during the period when it commenced its large mains replacement program.

Figure 3-19 illustrates the changes from 2011 to 2022 in reported volumes of UAFG as a proportion of total gas delivered for each distribution scheme pipeline. It shows that UAFG has remained stable on average, varying from 3.2% to 3.4% of delivered gas volumes.

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59 AER, *Final decision – AGN(Victoria and Albury) Access Arrangement 2023-28*, June 2023; AER, *Final decision – AusNet Access arrangement 2023-28*, June 2023; AER, *Final decision – Multinet Access arrangement 2023-28*, June 2023.

60 AEMO, *Gas statement of opportunities for central and eastern Australia*, March 2023, p. 7.

61 AEMO forecasts a decline in residential and small commercial users is based on the ISP 'Orchestrated Step Change (1.8°C) scenario' from 194PJ to 75PJ between 2022 to 2042.

AEMO, *Gas statement of opportunities for central and eastern Australia*, March 2023, p. 33.

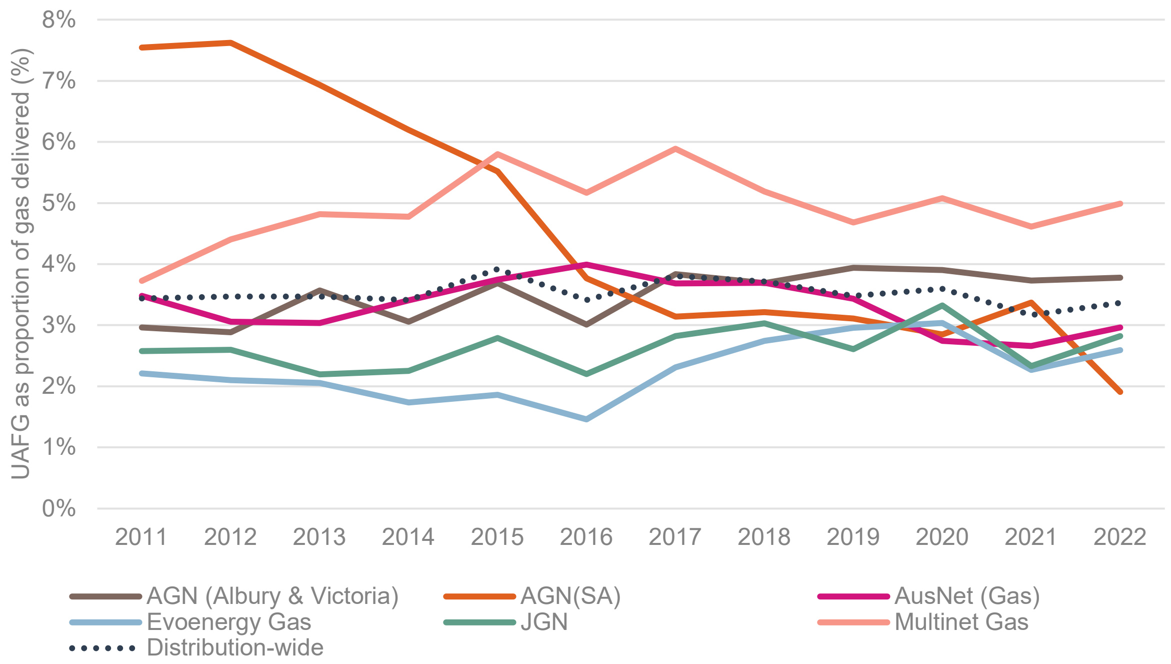
62 AEMO, *Gas statement of opportunities for central and eastern Australia*, March 2023, pp. 32-33.

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

64 AER, *Gas network performance report*, 2021, pp. 57–59.

65 ESCV, *Review of unaccounted for gas benchmarks: final decision*, December 2022, pp. 7–8.

Figure 3-19 UAFG as a proportion of gas delivered – distribution



Source: UAFG: Annual RINs – S11.3 UAFG – Transmission and Distribution; Gas delivered: Annual RINs – N1.1 Demand by customer type.

Note: AER calculation of UAFG as a percentage of gas delivered for each distribution scheme pipeline. Distribution-wide values calculated as network-wide UAFG divided by network-wide gas delivered.

Figure 3-19 shows that:

- While UAFG as a proportion of gas delivered increased from 3.2% to 3.4% between 2021 and 2022, it was still the second lowest it has been over the time series.
- In recent years, there was a narrower range of UAFG as a proportion of gas delivered between scheme pipelines than at the start of the measurement period in 2011. The reduction in the range was mostly driven by AGN (SA) changing from having materially high levels of UAFG as a proportion of gas in 2011 (7.6%) to having the lowest levels in 2022 (1.9%).
- UAFG measured displays variability from year-to-year with increased levels of UAFG for all NSPs except AGN (SA) and AusNet Gas Services between 2011 and 2022, contributing to a narrower range.
- While the drivers of UAFG are too complex to attribute precisely, we expect AGN (SA)'s large reductions in UAFG are partly an outcome of its ongoing mains replacement program, identified in section 3.2.

How UAFG costs impact the cost of reference services

UAFG is an important cost driver for distribution scheme pipelines though increasing fuel costs and the need for capex in mains replacement programs.

Distribution scheme pipelines pay for UAFG-related fuel costs in the ACT, NSW, and South Australia by directly contracting UAFG volumes. UAFG is therefore included in their allowed opex under our access arrangement decisions and recovered via reference prices. Distribution scheme pipelines are incentivised to reduce opex through base step trend opex forecasts and the efficiency carry over mechanism. If actual UAFG rates are below (above) forecast rates, the scheme pipeline will over (under) recover its actual UAFG costs. This will flow through to consumers via a lower (higher) opex forecast in the next access arrangement decision.

Victorian distribution scheme pipelines operate under a slightly different framework. The Victorian Essential Service Commission (ESCV) sets a benchmark rate of UAFG for each distribution scheme pipeline, measured as UAFG divided by total gas delivered. Gas retailers are required to contract sufficient gas to cover consumption and the actual UAFG. If actual UAFG is greater than the benchmark, the scheme pipeline must compensate retailers for the UAFG above the benchmark. Where actual UAFG is lower than the benchmark, retailers make reconciliation payments to the scheme pipeline. Since UAFG is considered via the ESCV benchmark process, we do not include it in opex forecasts for Victorian distribution scheme pipelines.

Under both frameworks, distribution scheme pipelines are only rewarded or penalised for changes in the relative UAFG volumes, or the benchmark rate. Scheme pipelines are not rewarded or penalised for changes in the absolute levels of UAFG or changes in gas prices. For scheme pipelines that directly contract UAFG, there is a true-up in the tariff variation mechanism for upstream gas prices or demand differing from approved forecasts.

3.4.3 Pipeline outages

Scheme pipelines are inherently reliable. This is in part because:

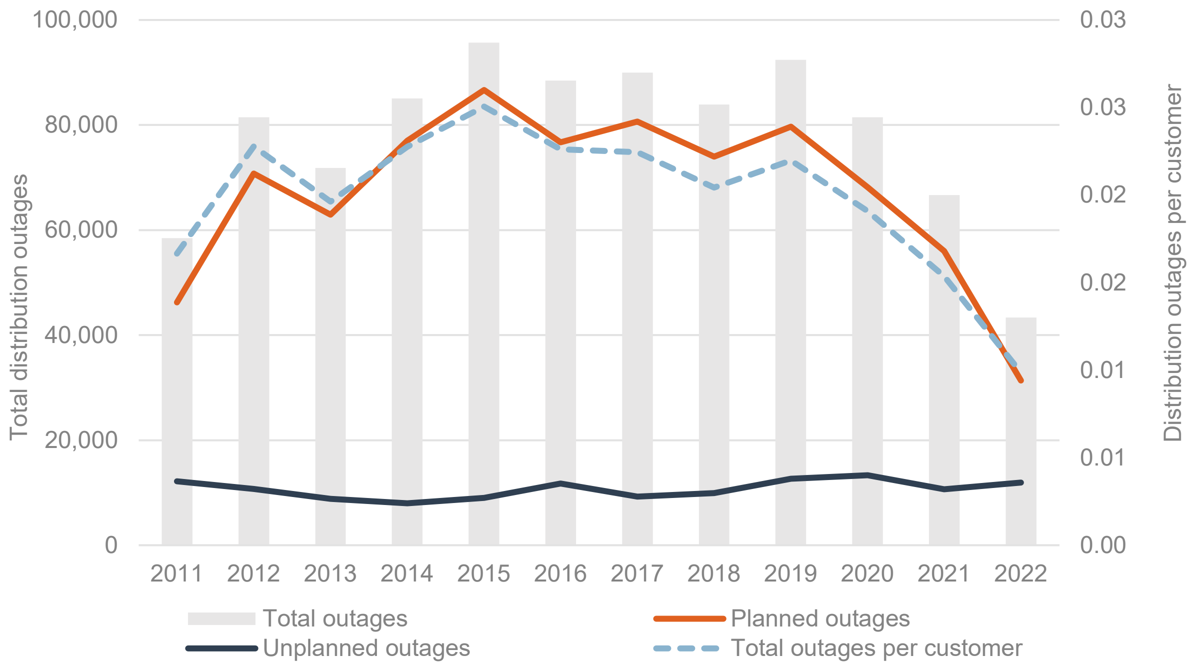
- By mainly being underground, pipelines are more protected from adverse environmental conditions than, for example, electricity networks.
- Scheme pipelines can carry out works without causing supply outages.

Due to these factors, outages are infrequent. For example, in 2022 there were less than 0.01 outages per customer on average.[66] This is equivalent to a customer experiencing an outage less than once every 100 years on average. Alongside the infrequent nature of pipeline outages, they also impact relatively few customers at once.

Nonetheless, since the consequences of outages can be material for the customers they do affect, we consider it important to monitor aggregate changes in outages over time. Figure 3-20 sets out total outages across the distribution scheme pipelines, divided into planned and unplanned outages.

[66] This differs from the SAIFI measure we report in electricity as we do not weight it by the number of customers impacted per outage, recognising than an outage can affect more than one customer at once.

Figure 3-20 Distribution scheme pipelines outages – Total and per customer



Source: Annual RINs – S11.1 Network outages.

Figure 3-20 shows that in 2022, total outages reached its lowest point since 2011, with a 44% reduction in planned outages compared to 2021. This represents a continued trend with planned outages in 2022 being lower than any other year since 2011 (and 35% lower than their peak in 2015). There are various potential drivers for the reduction in planned gas outages. For example, Evoenergy reported a material reduction in planned outages in 2022, which are almost entirely driven by meter replacements. This reduction was driven by Evoenergy changing its approach to determining whether a gas meter is at the end of its serviceable life.[67]

Conversely, unplanned outages increased 12% on 2021 levels. While unplanned outages are 2% lower than at the start of the series in 2011, they are 49% higher than the 2014 minimum. Directionally, this is not what we would expect with many distribution scheme pipelines having undertaken large mains replacements over the same period. However, we recognise that even at their highest levels, these unplanned outages remain rare for consumers. We will continue to monitor these outcomes and investigate what is driving outages in future reports.

When engaging on this data, we observed that different scheme pipelines may have adopted materially different approaches to reporting outages. As such, our view is that while Figure 3-20 and the underlying outage data is useful to monitor trends through time, it is less informative about the comparative reliability of individual scheme pipelines.

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67 Gas meters are deemed to have a minimum service life of 15 years. After which, if a meter batch passes 5 yearly testing (based on a statistical sample), Evoenergy requests a life extension from the Utilities Technical Regulator. While Evoenergy previously self-imposed a maximum meter life of 25 years, it now allows indefinite extensions subject to passing 5 yearly testing.

4 Financial performance in 2022

This section looks at financial performance, as a core performance outcome. This entails considering indicators of profit that scheme pipelines have been able to generate from providing reference services. We developed these indicators with stakeholder input at part of our profitability measures review.[68] These indicators include:

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

All analysis in this section is presented as (1) real returns, excluding annual returns from capital base indexation; and (2) including rewards and penalties arising from incentive schemes. Other permutations of these measures are available in our financial performance dataset, released alongside this report.[69]

Our analysis of financial performance reports both the return on asset and return on equity measures. However, our preferred measure is the return on assets rather than the return on equity because it also includes the return to assets funded by debt. The return on regulated equity is but one component of our allowed return on capital. Therefore, the return on assets is a better comparator which is unaffected by the return on equity measures exclusion of the return to assets funded by debt and a businesses' level of gearing.

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

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

- Differences in expenditure from the revenue allowances we determine. Under the regulatory regime, scheme pipelines can earn higher returns by seeking cost efficiencies, which consumers ultimately benefit from through lower expenditure allowances in subsequent access arrangement periods.
- Differences in the forecast demand used to calculate the weighted average price cap. A scheme pipeline might benefit from achieving higher demand than forecast, but this would also inform higher demand forecasts (and therefore lower prices) in subsequent access arrangement periods.

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68 AER, *Profitability measures for electricity and gas businesses*, 2019, accessed 4 April 2022.

69 Our profitability measures are published alongside explanatory notes. The explanatory notes provide additional information and guidance on the purpose of reporting the measure and methodologies, including relative comparators and limitations of individual measures.

- Departures from benchmarks in a way that does not affect costs to energy consumers. For example, scheme pipelines can earn higher returns when they bear more risk by holding a higher proportion of debt than the benchmark of 60%.[70] Scheme pipelines can also earn higher returns if they operate under a flow-through tax structure where a tax rate of less than the 30% benchmark applies.
- Additional revenue from performing well against incentive schemes. In our recent incentives review, we found that our incentive schemes improved outcomes for consumers, including through incentivising lower costs.[71]

Notwithstanding the above, profitability results that are systemically and materially different to our forecasts or benchmarks should prompt us to investigate the causes in more detail.

Allowed rates of return and the return on capital building block

The return on capital building block in our access arrangement determinations is made up of a return on debt and return on equity component. The allowed return on debt, for example, is made up of the amount of debt we forecast (capital base × gearing; where gearing is based on a benchmark of the ratio of assets financed with debt rather than equity) multiplied by the allowed rate of return on debt. Similarly, the return on equity component is calculated as the portion of the capital base funded by equity multiplied by the allowed return on equity.

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

4.1 Returns on assets

The return on assets is measured as EBIT divided by the capital base. It is a simple measure allowing us to compare scheme pipelines' profits against their allowed rates of return. The return on assets does not capture all potential profitability drivers, such as performance against our allowances for the costs of debt (interest expense).

- In 2022, the average return on assets for scheme pipelines fell by 90 basis points on its previous low in 2021 and is now 4.3%.[72]
- Both average returns on assets and allowed rates of return have been declining over 2014–2022, which has been driven in large part by lower allowed returns on capital.
- Scheme pipelines remain profitable with the average return on assets consistently above the allowed rate of return since 2014. However, the margin of outperformance has become more modest, reaching 120 basis points in 2022.

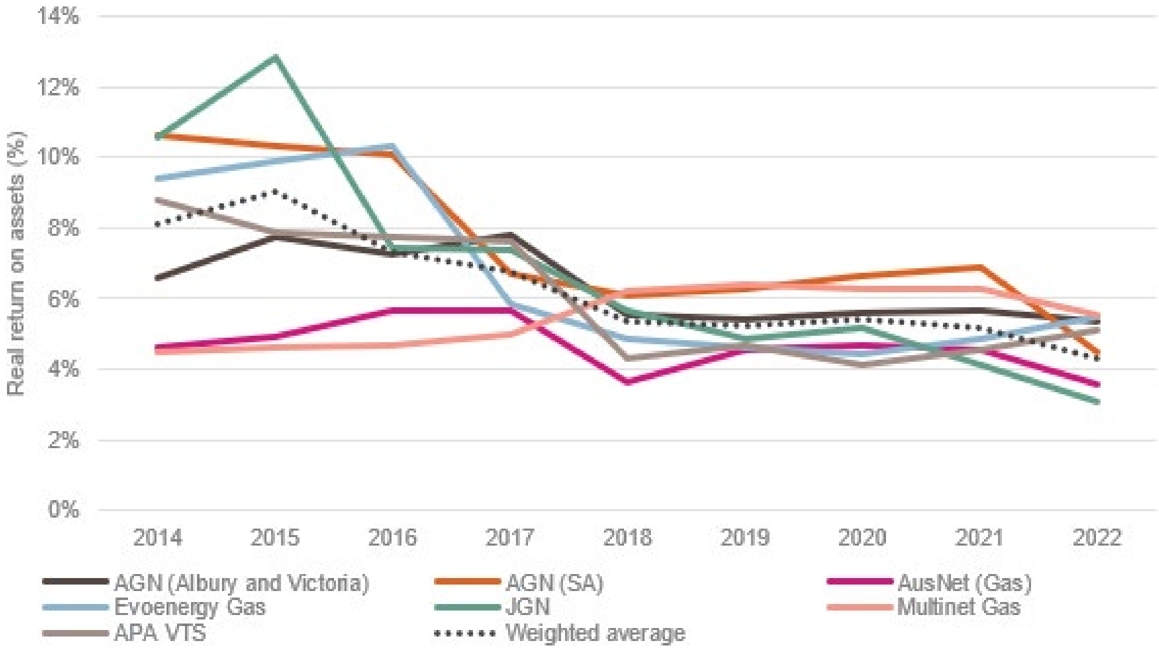
70 Scheme pipelines will balance the lower costs they can achieve from having higher gearing against the negative impact that higher gearing can have on their credit ratings and ability to raise debt at lower costs.

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

72 Note: Analysis excludes Amadeus Gas Pipeline and RBP.

Figure 4-1 shows how scheme pipelines' returns on assets changed over 2014–2022.

Figure 4-1 Regulatory returns on assets – scheme pipelines



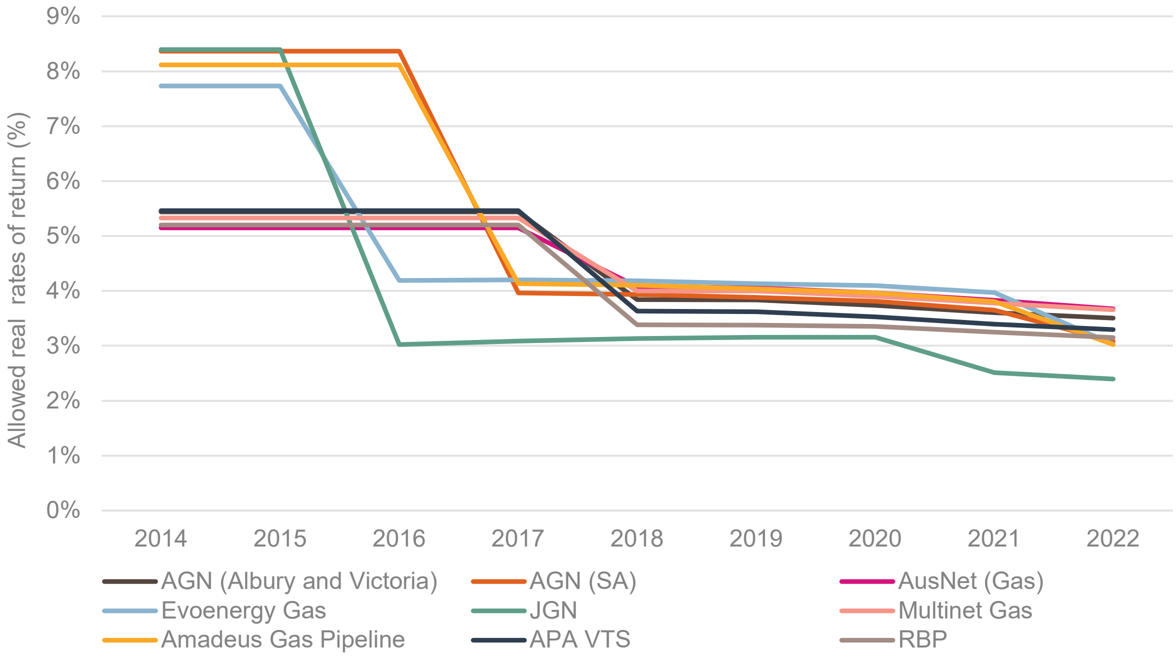
Source: Financial performance data.

Notes: Excludes Amadeus and RBP. Calculation details are provided in the financial performance data and return on assets explanatory note. Averages are weighted by the opening nominal capital base in the financial performance data.

Figure 4-1 shows that returns on assets have declined over 2014–2022, and the range of outcomes between the individual scheme pipelines has narrowed since 2018. These results are driven by a range of factors, the most material of which appears to be the decline and convergence of allowed rates of return, which is a major driver of building block revenue.

Figure 4-2 shows how the allowed real rate of return has changed among scheme pipelines. Allowed rates of return shifted from visibly changing every 5 years to having incremental annual changes after the 2013 rate of return guideline came into effect from 2015. This is when we introduced the 10-year trailing average approach, which assumed a benchmark efficient entity would refinance 10% of its debt portfolio each year. Prior to the 2013 guideline, we reset both allowed returns of debt and equity every 5 years.

Figure 4-2 Allowed real rates of return

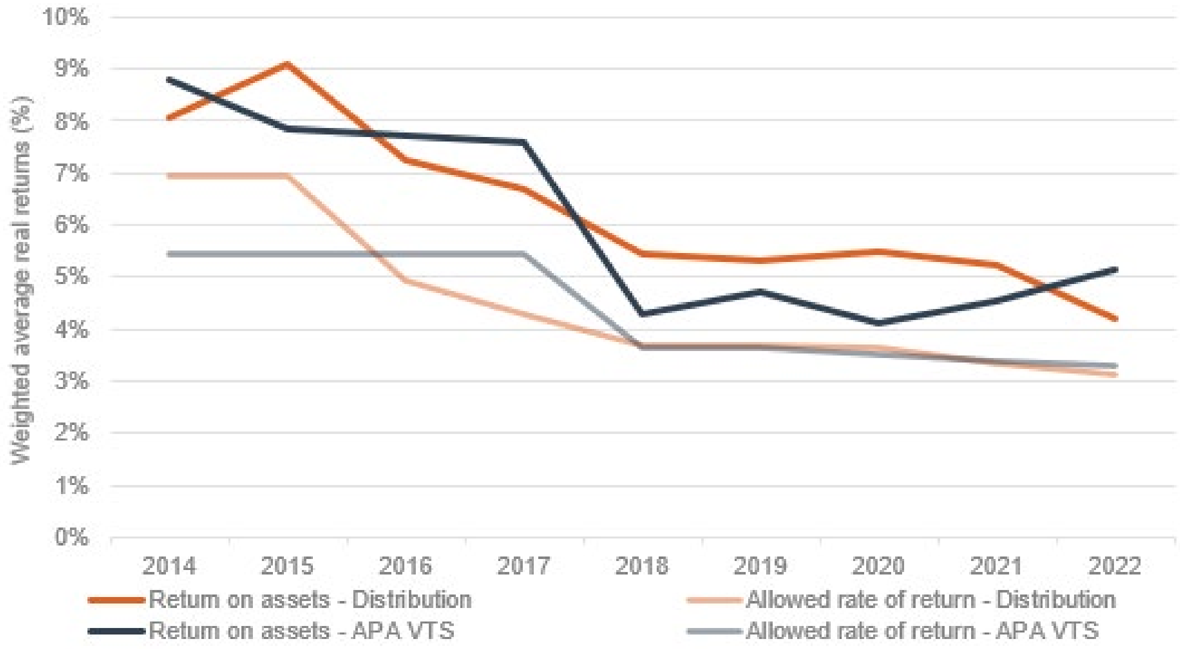


Source: Financial performance data – Summary – Gas DX/TX, PTRM – WACC.

Allowed real rates of return shown in Figure 4-2 have been reducing since 2015. In addition to moving to a trailing average approach, our 2013 rate of return guideline also adopted more modest equity parameters. Our decisions also coincided with interest rates being materially lower than in the previous cycle of decisions, thereby lowering debt and equity costs. We since made further changes to improve our equity and debt parameters as part our 2018 rate of return instrument. These improvements contributed to further reductions in allowed rates of return and were applied first to JGN in 2021 and then to AGN (SA), Evoenergy Gas and Amadeus in 2022. The resulting reductions are shown in Figure 4-2. However, based on higher interest rates and inflation in current market data, we expect to see rates of return increase over at least the short to medium term.

While actual and allowed rates of return have both declined, Figure 4-3 shows that scheme pipelines have generated returns consistently and materially above allowed returns.

Figure 4-3 Actual and allowed returns on assets



Source: Real WACC: PTRM – WACC. Average real return on assets: Financial performance data.

Note: Figure excludes Amadeus and RBP. Calculation details are provided in the financial performance data and return on assets explanatory note. Averages are weighted by the opening nominal capital base in the financial performance data.

This margin between actual and allowed returns reflects several factors, including:

- What we collectively term 'revenue effects'. For scheme pipelines, this mainly reflects under or over recovery of revenue due to gas demand being lower or higher than forecast. Revenue effects can also include the effects of remittals and revenue smoothing.[73]
- Opex, which can be calculated by substituting actual with forecast opex and calculating the incremental change in returns. Opex will contribute to a higher return on assets if scheme pipelines underspend their opex allowance.
- Capex, which can be calculated by substituting actual with forecast capex and calculating the incremental change in returns. Capex will contribute to a higher return on assets if scheme pipelines underspend their capex allowance.
- Incentives, which we can calculate by removing rewards or penalties received from incentive schemes and calculating the incremental change in returns. Incentives will contribute to higher returns on assets if on average scheme pipelines spend less than their target opex or capex.[74] This outperformance will contribute to lower expenditure

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73 Revenue smoothing means that in any given year, unsmoothed revenue (that is, forecast building block revenue) and smoothed revenue can materially differ—holding forecast demand constant.

74 Our determinations and decisions set out whether the efficiency benefit sharing scheme (EBSS) or capital expenditure sharing scheme (CESS) will apply to operating expenditure or capital expenditure over the forecast regulatory control period or access arrangement period.

allowances in the following period, thereby providing an incremental cost saving to consumers.

4.2 EBIT per customer

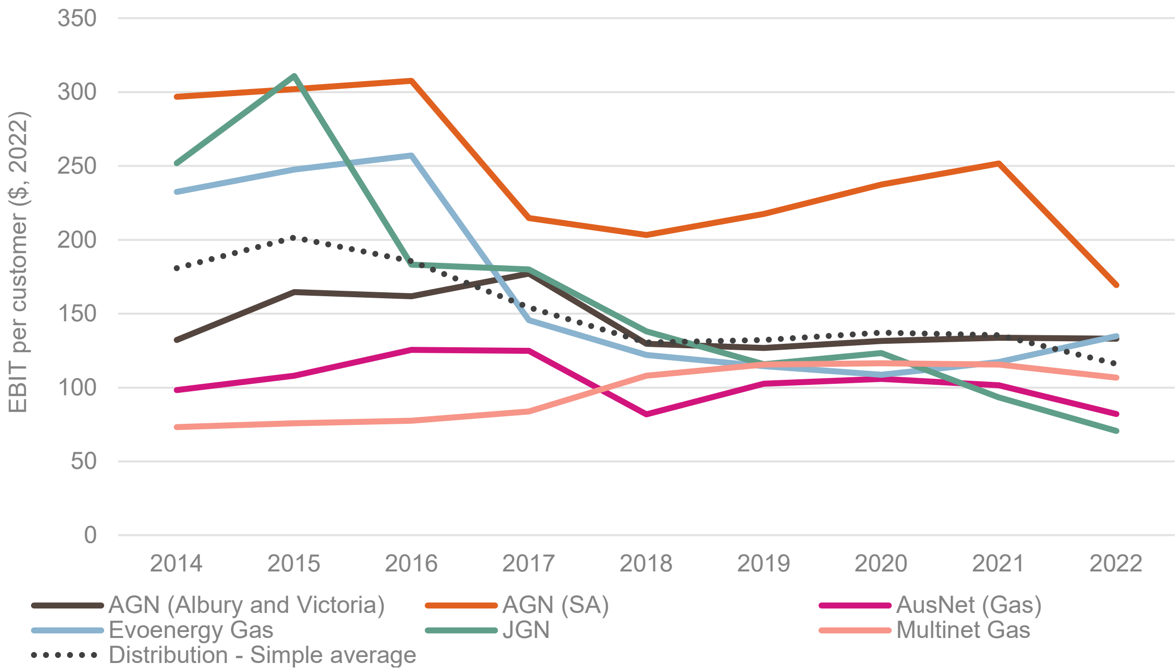
EBIT per customer is a measure of a scheme pipeline's operating profit divided by its customer base. It is a complementary measure to the return on assets, capturing the same measure of profit (EBIT) over a different cost driver.[75]

EBIT per customer is *not* a measure of the profit that individual residential consumers contribute to the scheme pipelines. It is an average of all consumers, including commercial and industrial customers, who may contribute a greater proportion of network revenue per customer despite their smaller numbers.

- EBIT per customer in 2022 fell to its lowest recorded level of $114 – a 16% decrease since 2021.
- EBIT per customer has been declining since 2014, which has been largely driven by lower allowed rates of return. This result aligns with changes in the return on assets.

Figure 4-4 sets out the average real EBIT per customer, including incentive scheme payments and excluding the impacts of capital base indexation.

Figure 4-4 EBIT per customer – distribution scheme pipelines



75 We only report EBIT per customer for distribution as transmission scheme pipelines service a small number of very large gas users (for example, generators). As such, EBIT per customer would provide little meaningful information in which to draw comparisons and insights for transmission.

Source: Financial performance data

Note: Model includes AER calculation, with more information in our EBIT per customer explanatory note. Distribution scheme pipeline average is calculated as a simple average of each distribution scheme pipeline's EBIT per customer.

Figure 4-4 shows that EBIT per customer had been increasing since 2018 for AGN (SA), reflecting that it had commenced a major mains replacement program.[76]

Despite AGN (SA) still having the highest EBIT per customer, this decreased by 33% in 2022. While AGN (SA) is continuing to require revenue to undertake its ongoing mains replacement program[77], its EBIT per customer is lowered by us approving accelerated depreciation.[78] In 2022, nominal straight-line depreciation (one of the items deducted from profit to calculate EBIT) increased from around $65 million to $91 million. AGN (SA) also received a lower allowed return on equity in 2022 as this marked the first application of the 2018 rate of return instrument to AGN (SA).[79]

4.3 Returns on regulated equity

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

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

The return on regulated equity is a measure that is bespoke to businesses operating under our or comparable regulatory regimes. Therefore, care is required in interpreting this measure, as it cannot necessarily be directly compared with returns on equity achieved by firms operating in the broader competitive market.

Specifically, this measure reflects the treatment of regulated revenue and expenses in the building block revenue framework and in our models—for example, valuing regulated assets using the capital base rather than a separate book or market value. This is necessary for making comparisons with our allowed return on equity, but also means there are differences between our approach and how returns on equity would ordinarily be calculated. Our analysis and financial performance data should be considered alongside our profitability

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76 AGN(SA) incurred 272.4 million ($2020-21) on mains replacement capex over the 2016–2021 access arrangement period. See AER, *Final decision -AG(SA) access arrangement 2021–26 – Attachment 5 – Capital expenditure*, April 2021, p. 11.

77 We approved 230.3 million ($2020-21) of mains replacement capex for AGN (SA) in its 2021–26 access arrangement period. See AER, *Final decision -AGN(SA) access arrangement 2021–26 – Attachment 5 – Capital expenditure*, April 2021, p. 5.

78 We approved 245.1 million ($2020-21) of accelerated depreciation for replaced mains and inlet assets in AER, *Final decision -AGN(SA) access arrangement 2021–26 – Attachment 4 – Regulatory depreciation*, April 2021, p. 8.

79 AGN's allowed real return on equity decreased from 4.60% to 3.30% between 2021 and 2022.

measures review final decision[80] as well as our explanatory note and illustrative return on regulated equity model published alongside this report.

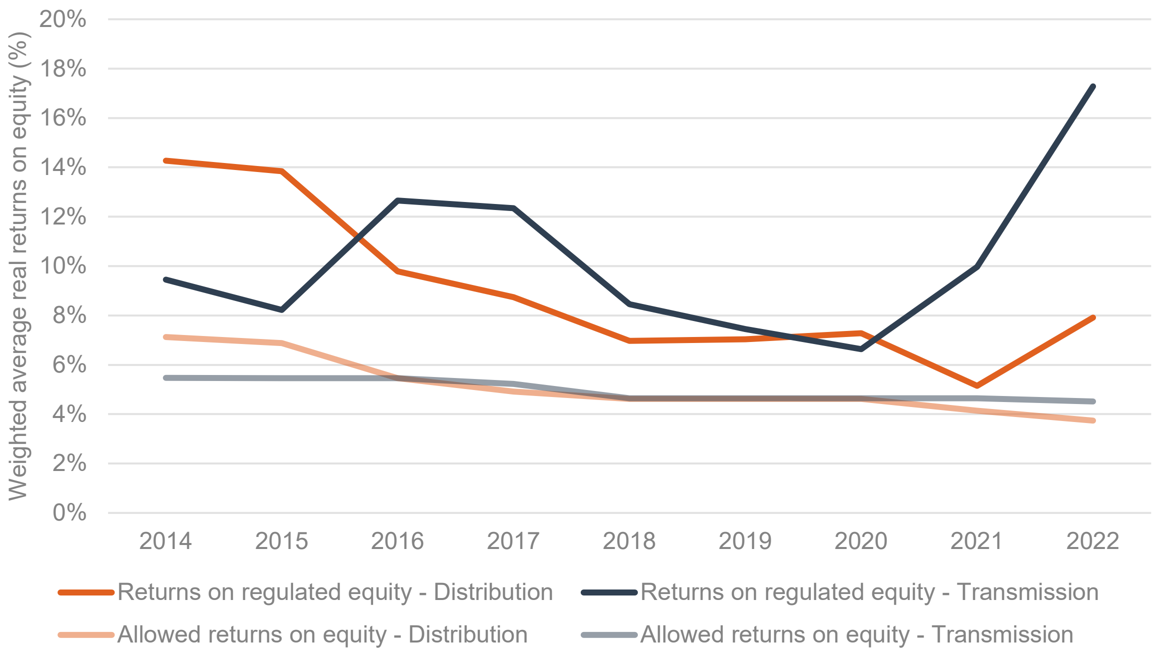
- Over 2014 to 2022, returns on regulated equity achieved by scheme pipelines have exceeded allowed returns on equity on average.
- On average, returns on regulated equity for scheme pipelines have generally declined over 2014 to 2021. These declines occurred against a backdrop of declining allowed returns on equity, reflecting both a lower interest rate environment and improved benchmarks under our 2013 rate of return guidelines and 2018 binding rate of return instrument.
- Returns on regulated equity increased in 2022 by 2.8 percentage points for distribution (now 7.9%) and 7.3 percentage points for transmission (now 17.3%). Returns on regulated equity had already increased for transmission in 2021 by 3.3 percentage points since 2020.[81]
- The higher measured returns on regulated equity achieved in 2022 are primarily due to inflation being higher than forecast, which increases returns from capital base indexation. This driver is affecting transmission returns earlier than distribution returns because capital base indexation applies with less of a lag to APA VTS and RBP than to other scheme pipelines. We explain this driver in section 4.3.2 below.

Figure 4-5 indicates that the average return on regulated equity invested into scheme pipelines has consistently been greater than forecast since 2014. It is also worth acknowledging that underneath the average results, there is a spectrum of outcomes between scheme pipelines.

Figure 4-5 Real return on regulated equity compared to allowed returns on equity

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

81 Our results in 2023 provide for updates to correct a timing recognition error in application of implied gearing for APA.



Source: Financial performance data.

Note: Financial performance data includes AER calculation, with more information in our return on regulated equity explanatory note. Averages are weighted by the size of each scheme pipeline's equity base. It is important to note that while the transmission pipeline returns to regulated equity are reported across the three scheme pipelines, the VTS has twice the equity base of RBP and 8 times the equity base of AGP. The VTS estimated actual return on equity is largely affected by the amount of capital base indexation captured in equity returns attributable to debt which reflects actual inflation of 7.83 per cent in 2022.

Whether the results in Figure 4-5 are evidence of the framework operating effectively or not depends on the drivers of the results, which we discuss in the next section.

4.3.1 Drivers of differences in actual and allowed returns on equity

The regulatory framework is designed to encourage efficiency in the long run interest of consumers. Given this design, it is not unexpected that scheme pipelines' returns would exceed allowed returns under a regulatory framework that provides them with a reasonable opportunity to recover at least the efficient costs of providing reference services.[82] Whether these results are evidence of the framework operating effectively or not depends on the source of deviations, their materiality, or whether the outcomes are persistent or not. Outcome may be affected by:

82 NGL, s.24 – Revenue and pricing principles relating to scheme pipelines.

- Temporary revenue over-collections which will be passed back to consumers in the short-term, due to smoothing of revenues to reduce price volatility or other revenue adjustments.[83]
- Departures from our benchmark financing structures, which do not result in consumers paying more for reference services. Rather, these reflect that some scheme pipelines have chosen to take on higher risk to achieve higher returns for themselves.
- Scheme pipelines spending less than forecast revenue building blocks due to efficiency gains.
- Scheme pipelines spending less than forecast revenue building blocks due to forecasting errors. Including forecasting errors due to genuinely unforeseen circumstances, such as an unexpected decision of a major user to connect or disconnect from the network.[84]

Figure 4-6 illustrates that a combination of factors has driven differences in the margin between allowed real returns on equity and actual real returns on regulated equity. It does not show the impact of tax structure, which has no effect because scheme pipelines report being taxed as companies, National Tax Equivalent Regime (NTER) entities or government owned non-NTER entities where a tax rate of 30% applies.[85]

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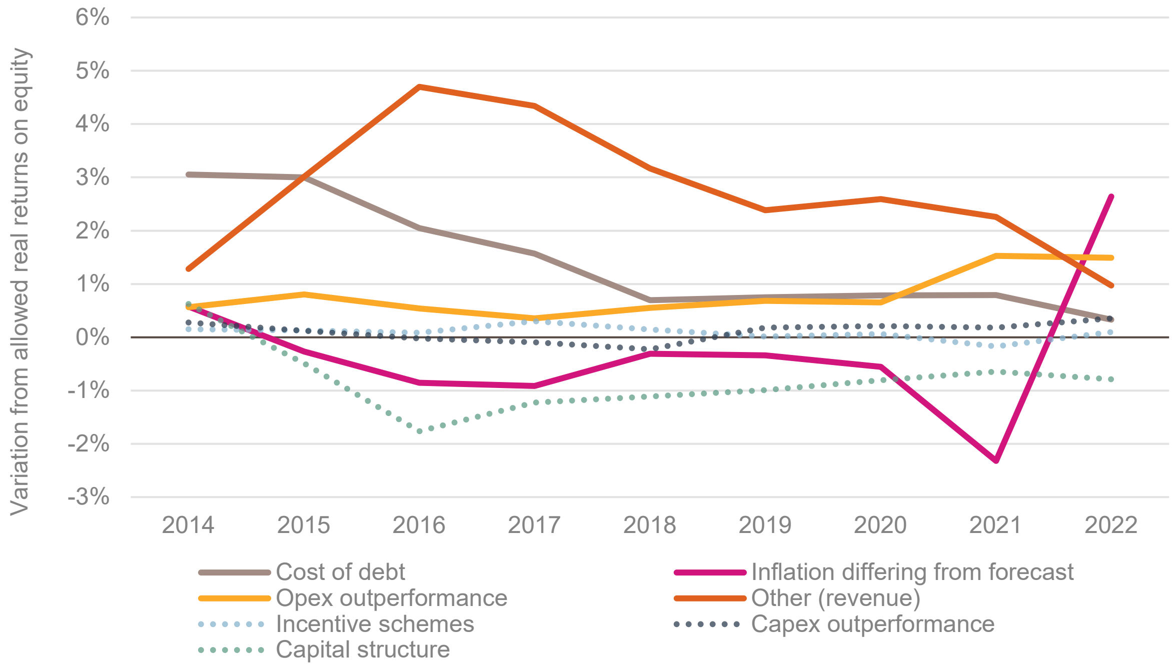
83 The revenue smoothing we apply when estimating scheme pipelines' revenue recovery paths will result in temporary revenue over- and under-recovery, which evens out over time. JGN's remittal adjustment is an example of 'other revenue adjustment', which shifted an adjustment for over-recovery in one access arrangement period to the following access arrangement period.

84 Under the incentive framework, we rely on revealed (actual) costs to inform our estimate of service providers costs into the future, As stated previously where profitability results are systemically and materially different to our forecasts or benchmarks it serves as a prompt to investigate the causes in more detail. Such investigations or reviews of our approach are intended to improve efficiency outcomes for consumers. For example, the introduction of better regulation, changes to our approach to estimate the rate of return, and tax review have resulted in better estimates of forecast costs to the benefit of consumers.

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

Figure 4-6 Contributions to real returns on regulated equity



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

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

*Real returns exclude returns from indexation of the equity-funded portion of the capital base that would otherwise capture returns from differences in forecast and actual inflation, which are outside of a scheme pipeline's control. As debt is always in nominal terms, our estimates capture differences in forecast and actual inflation through the indexation of the debt-funded portion of the capital base.

The key drivers of real returns on regulated equity varying from allowed real returns on equity from 2014 to 2022 shown in Figure 4-6 include:

- Other (revenue effects), contributed annually on average 2.24 per cent to actual returns above forecast, reflecting a number of factors. [86] The main driver is that scheme pipelines can earn above or below forecast revenue over time due to changes in demand. Differences between forecast and actual demand in any year can result in higher or lower returns, which scheme pipelines keep – notwithstanding that demand forecasts next period will be influenced by the previous periods actual demand. For

86 Scheme pipelines also experience revenue effects from revenue smoothing. However, this effect is temporary because if revenue smoothing leads to a higher actual return one year, the difference will be reversed in future years. Remittals of AER decisions have also produced revenue effects. However, we do not anticipate seeing this effect in future years now that our decisions are no longer subject to limited merits review.

example, higher actual demand would tend to reduce average fixed costs in future periods.

- Cost of debt, which had an average positive contribution of 1.57 per cent. A positive contribution occurs if scheme pipelines on average raise debt at a lower cost than what is provided for in the allowed return on debt. We observe declines in the level of outperformance on cost of debt over the period. In 2022, this driver added 10 basis points to the average return on regulated equity—compared to 3.04 per cent in 2014. This suggests we currently set the allowed return on debt at a similar rate to what it costs scheme pipelines to raise debt on average.[87]
- Opex outperformance contributed positively on average 0.97 per cent per year over the period. [88] Opex outperformance will contribute to a higher return if scheme pipelines underspend their opex allowance. However, it does not reflect opex efficiency incentive rewards or penalties under the EBSS, which are instead captured under incentive schemes.
- Incentive scheme rewards and penalties made a minor incremental positive contribution of on average 0.05 per cent per year to returns on regulated equity. Incentive schemes contribute to higher returns if scheme pipelines receive higher rewards than penalties. We note the application of incentive schemes to gas networks has been limited in the past. [89]
- Capital structure, which reflects departures from the AER's benchmark financing structures. These departures do not affect what consumers pay for reference services. Rather, these reflect that some scheme pipelines have chosen to hold a different proportion of debt to the 60% assumed in our benchmark to either reduce their risk or increase returns to equity.
- Inflation rate variation, contributed positively to returns on regulated equity in 2022 due to higher actual inflation than forecast.[90] Our estimates of real returns on regulated equity identify the effect of inflation being higher or lower than forecast through the indexation of the capital base, net of indexation returns to equity holders. Given we are identifying this effect for scheme pipelines for the first time, we discuss this in further detail in section 4.3.2.

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87 Our 2022 Rate of Return Instrument identified an observed discrepancy between the benchmark and NSPs actual cost of debt arising in part due to differences in the term of debt. After accounting for different terms to maturity using a weighted average term to maturity and matched term analysis we found the matched term analysis accounted for the discrepancy; AER, *Rate of return instrument – Explanatory statement*, February 2023, pp.20-21.

88 We calculate opex outperformance by substituting actual with forecast opex and calculating the incremental change in returns.

89 To date, this has only included opex efficiency incentives under the EBSS given the infancy of the CESS in applying to scheme pipelines. Once scheme pipelines start receiving incentive payments and penalties under the CESS, incentive schemes will likely have a more material impact on returns on regulated equity.

90 We calculate the contribution of inflation by substituting actual inflation with forecast inflation and calculating the incremental change in returns.

4.3.2 Impact of inflation on returns on regulated equity

Capital base indexation compensates scheme pipelines for the impact of inflation. As such, we target a real return for scheme pipelines. Our published financial models include our preferred method for indexing the capital base.[91] The National Gas Rules allows the AER to prepare a capital base roll forward model in consultation with stakeholders.[92] Under our approach the targeting of a real return reduces price volatility because real returns are more stable than nominal returns, which are impacted by inflation expectations. In addition, this better aligns networks charges to general price levels experienced by consumers.

Where inflation is above or below forecast inflation, the real return on assets is not impacted. However, equity holders will make a higher (lower) return where actual inflation is above (below) forecast. This is because equity holders generally bear the inflation risk on the entire regulatory asset base given debt is normally issued in nominal terms. These inflation returns are not abnormal returns, they reflect outturn inflation risk that equity holders have incurred, and do not impact the real network charges consumers pay.

Our analysis identifies the recent shift from a very low to a higher inflation rate environment as a contributing factor to higher returns on regulated equity. Figure 4-7 illustrates how this shift affected the actual inflation rate applied to index scheme pipelines' capital bases on average.[93] It also shows how actual inflation as measured by the Consumer Price Index (CPI) diverged from forecasts and the effect this had on real returns on regulated equity over the past decade.

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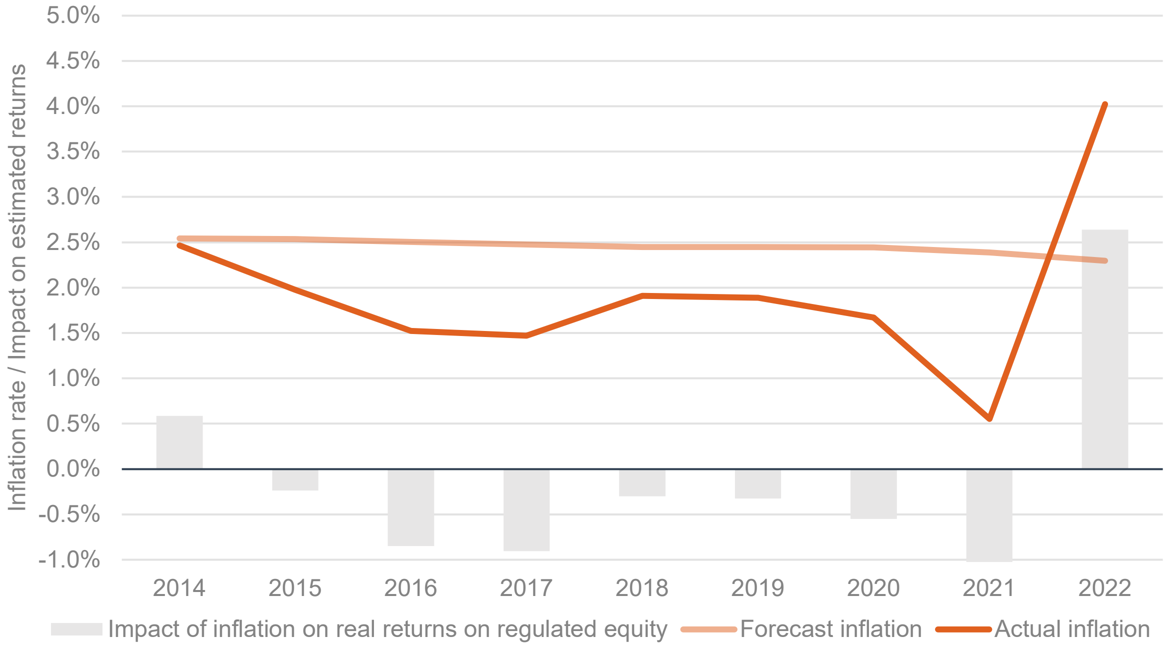
91 AER, *Post-tax revenue model handbook | Gas distribution service providers*, April 2020, p. 22; AER, *Post-tax revenue model handbook | Gas transmission service providers*, April 2020, p. 22.

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

93 The AER applies different inflation rates to index scheme pipelines' capital bases in accordance with each scheme pipeline's control mechanism.

Figure 4-7 Forecast and actual inflation – impact on real returns on regulated equity



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

Notes: AER calculation of the differences in the return on regulated equity when actual inflation is substituted for the forecast used in the AER's access arrangement determination. Values are weighted by the equity base of scheme pipelines.

Figure 4-7 illustrates how differences between the forecast and actual inflation applied to index the capital base affects real returns on regulated equity. When actual inflation is below expected levels used in our forecasts, as occurred between 2014 and 2021, lower indexation of interest-bearing liabilities has a negative effect on returns on regulated equity relative to allowed returns. When actual inflation is higher than forecast inflation, as occurred in 2022, higher indexation has a positive impact on returns on regulated equity. These effects are amplified in networks that are financed with a higher proportion of interest-bearing liabilities than our benchmark gearing level of 60%, and vice versa.

It is worth noting that the average actual inflation applied to scheme pipelines in 2022 is low relative to the high inflation rate environment that year because we apply indexation with a lag to certain scheme pipelines. The application of lagged inflation implies actual inflation is likely to be materially higher in 2023. For example, inflation applied to APA VTS is 'unlagged' and therefore a higher actual inflation rate of 7.83% was applied to it in 2022, relative to other scheme pipelines.

An unexpected high-inflation environment contributes to scheme pipelines achieving higher nominal returns in the short term. In the longer term, if higher inflation is expected to be persistent, these expectations are likely to be reflected in future revenue decisions. The result being higher forecast inflation in subsequent access arrangement periods and a lower likelihood of further returns from capital base indexation due to inflation being higher than expected.

As an outcome of our 2020 inflation review[94], we changed the inflation term from 10 years to 5 years. This allows forecast inflation rates used in our access arrangement decisions to be more responsive to changes in market circumstances. This change will likely lead to a lower difference between forecast and actual inflation than would have otherwise been the case.

Why indexation affects real returns on regulated equity

The National Gas Rules allows the AER to prepare a capital base roll forward model in consultation with stakeholders.[95] Our published financial models include our preferred method for indexing the capital base.[96] Capital base indexation compensates scheme pipelines for the impact of inflation. As such, we target a real return for scheme pipelines. Overall, returns would not be lower in the absence of capital base indexation.

Compared to including returns for inflation in the revenue allowance, indexation of the capital base leads to smoother revenue recovery and therefore prices. It also reduces the short-term increase in revenue that occurs when assets are replaced at the end of their useful lives.

Under our regulatory approach, we calculate a nominal rate of return and index the capital base. To target a real rate of return, we account for inflation by applying a negative revenue adjustment (to the nominal depreciation of the capital base) to ensure that the impact of inflation is not double counted.

When estimating the actual real return on regulatory equity we maintain consistency with this approach and reflect that debt is raised in nominal terms, by adjusting the NPAT for the indexed proportion of the capital base funded by interest-bearing liabilities. Therefore, our approach to calculate real returns on regulated equity, differs from:

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

Before capital bases are indexed in line with actual CPI, we apply a forecast of inflation when modelling capital base growth and returns. As such, returns on regulated equity increase when CPI is higher than the forecast inflation rate. Our calculation of actual real return on regulated equity achieved by scheme pipelines is affected by our adjustment for the proportion of indexation attributable to debt. It is important to note, this does not result in immediately higher cash flows commensurate with the level of indexation. Rather, this results in an adjustment to the capital base on which scheme pipelines will earn revenue that would otherwise reflect the targeted real return over the life of the assets.

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

94 AER, *Review of treatment of inflation 2020*, accessed 15 August 2023.

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

96 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.

5 Looking ahead

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

- On the electricity side, an inaugural report for release at the end of the year on the performance of electricity distribution networks in providing distribution services for embedded generators (such as residential solar) to export into the network.[97]
- PowerBI gas and electricity networks data dashboards for release when the AER's website is upgraded to support dashboards (currently expected in 2024). Our intention is for dashboards to provide a more user-friendly means for people to drill down into the measures and graphs presented in the written reports.

As such, the potential focus areas identified last year could be included as focus areas in 2024. These areas include (1) scheme pipelines' actions to prepare for a low carbon future and (2) analysis of demand forecasting and actual demand.

We will introduce a new approach to our reporting in 2024, summarised in Figure 5-1. Under the new approach, we intend to align our timeframes for gas and electricity performance reporting and work towards a mid-year release of core measures as a networks data dashboard. We then intend to engage with stakeholders and undertake focus areas in the second half of the year.

Our engagement with consumer groups this year confirmed the above potential focus areas remain a priority. In 2024, our approach would be to consult with stakeholders in the event more pertinent topics arise after publishing our data, or we have developed analysis on these topics.

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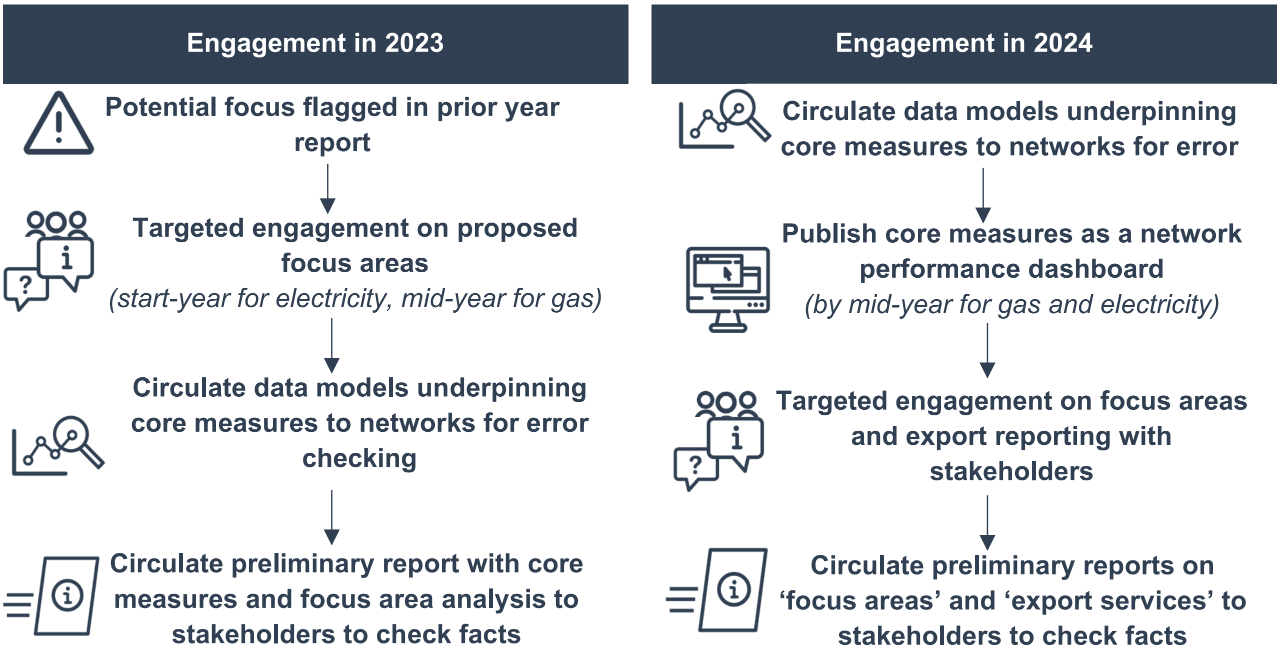
[97] Rule 6.27A of the NER: *Annual DER network service provider performance report*, accessed 7 June 2022.

Figure 5-1: Summary of new engagement approach to trial



Source: AER analysis.

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

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

Over the coming years, there may be an opportunity for us to enhance our gas network performance reports following our new monitoring and reporting function under the National Gas Law.[98] In March 2025, we will provide a report to the Ministerial Council on Energy on our work in monitoring both scheme and non-scheme pipelines, which we will then publish as

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98 Government of South Australia, *National Gas (South Australia) Act 2008*, Version 27 April 2023.

an aggregated version that is not likely to identify particular service providers.[99] Given the aggregated and deidentified nature of this public report, we expect the content of our gas network performance reports will continue to be valuable and non-duplicative. However, our network performance reports could benefit from the additional data on the scheme pipelines covered in this report that will be collected under our new monitoring function. This data will include financial information, prices, non-price terms and conditions, access negotiation outcomes and compliance information.[100]

We encourage feedback on our network performance reports and accompanying data resources so we can improve their usefulness over time. We also welcome research suggestions and expressions of interest to engage from stakeholders, who can contact us at networkperformancereporting@aer.gov.au.

[99] *National Gas (South Australia) Act 2008*, subsection 63B(1).

[100] *National Gas (South Australia) Act 2008*, section 63A.

Appendix A: Objectives of network performance reporting

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

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

Objective	What we are doing
Provide an accessible information resource	We have drafted this report to be informative and accessible for stakeholders. Alongside this report, we have published two data models covering: • Our operational performance data. • Our financial performance data. These models include much of the data captured in this report at a greater level of detail. We aim to present the data in a form that enables stakeholders to use it in their own analysis.
Improve transparency	Through the report and our published data, we are trying to illustrate the impacts and interactions of network performance under different regulatory tools or settings. The regulatory regime can be complex. Our objective through this reporting is to make network regulation and its outcomes more transparent for stakeholders. For example, we have provided key performance measures to assist stakeholders in gaining preliminary views on the regulatory framework.
Improve accountability	The focus of this report is on the effectiveness of network regulation as a whole, increasing accountability for our regulatory decisions and for scheme pipelines' performance under those decisions. Further, our published data allows for comparisons between scheme pipelines. Our published data and analysis highlights areas where scheme pipelines depart from broader trends.
Encourage improved performance	By improving accountability and transparency, these reports should contribute to improved performance over time by: • Informing ourselves and stakeholders about emerging trends that may require a regulatory response. • Contributing to the incentives on scheme pipelines to improve performance.
Inform consideration of the effectiveness of the regulatory regime	Our analysis in this report is intended to support consideration of how the regulatory regime contributes to network performance and outcomes. We aim to explore where actual outcomes depart from forecasts or trends, whether this is widespread and what implications that has for our regulatory approaches.
Improve network data resources	Through our analysis of the data, we have sought to: • Investigate and make use of a wide range of our network data sources.

	• Identify and manage differences in reporting that impede comparability of data provided by different scheme pipelines. • Identify important questions on which we would like to form views but are limited by data availability or consistency. Over time, we expect this approach will also assist us to form a view on any data we currently collect that may be excessive or not useful.

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