# Gas network performance report

2022

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# Contents

# 1 Summary and key findings

This is our second annual gas network performance report. It covers performance over the regulatory years ending in 2011 through to 2021. It also expands on our first report by covering transmission as well as distribution network service providers (TNSPs, DNSPs –NSPs collectively) and by reporting returns on regulated equity (RoRE). The RoRE illustrates the final returns available to equity holders after all expenses and allows for a comprehensive comparison of NSPs' actual returns against expected returns.

Our gas network performance reports analyse key outcomes and trends in the operational and financial performance data we collect from fully regulated gas NSPs. These reports aid us in systematically investigating whether the costs of reference services are balanced with service outcomes arising from those costs, in alignment with our performance reporting priorities (summarised in Appendix A). An effective regulatory regime that contributes to consumers paying no more than is necessary for a safe and secure supply of energy should achieve such a balance.

Our key operational performance findings include:

- Regulated revenue that DNSPs collect from consumers decreased by 7.3% in 2021 and has been following a clear downwards trend on a per customer basis since 2015. In 2021, revenue decreased for Roma to Brisbane Pipeline (RBP) by 7.8% and increased for APA Victorian Transmission System (VTS) by 11.0% in 2021.
- NSPs have been recovering more revenue than forecast consistently and to an increasing extent. A lot of this outperformance appears to be demand-driven—such as DNSP customer numbers growing faster than forecast. Gas NSPs are regulated under price caps, which incentivise them to increase demand where beneficial to reduce the unit costs faced by consumers.
- In 2021, DNSP expenditure increased by 1.1% remaining low relative to the peak in 2014. TNSP expenditure increased 15%. Most annual variation in expenditure is driven by capital expenditure (capex). Capex is particularly variable for TNSPs, which have fewer assets and less connections expenditure.
- While TNSPs incurred materially more capex than forecast in most years, capex forecasting has visibly improved since 2011 (see Figure 4-21 and Figure 4-22)
- Capital asset bases (capital bases) have flattened in the last couple of years, with the capital intensiveness of most NSPs reducing due to growth in customer numbers for DNSPs and gas delivered for TNSPs (see section 4.3). An exception to this is AGN (SA), whose mains replacement program widened its relative capital-intensity.
- Gas networks are inherently reliable and had reliability improvements in 2021. Unaccounted for gas (UAFG) levels declined 11.5% over 2021 and distribution network outages were at their lowest level since 2011, driven by a trend of lower planned outages.

Our key financial performance findings include:

- NSPs remain profitable. In 2021, DNSPs and TNSPs (excluding Amadeus) generated returns on assets greater than forecast by approximately 200 and 230 basis points, respectively.
- For DNSPs, returns on assets and earnings before interest and tax (EBIT) per customer continued declining on average, driven by lower forecast rates of return. TNSPs' (excluding Amadeus's) returns on assets followed a downwards trend since 2017.
- On average, NSPs earnt higher RoRE than our benchmark allowed return on equity. However, the margin of outperformance has been narrowing over time, particularly as we have been revising our approach to setting allowed rates of return and improving the accuracy of our expenditure forecasts.
    - In 2021, average RoRE exceeded allowed returns on equity by 357 and 179 basis points on a simple average and weighted average basis, respectively.
    - In contrast, over the 2014–2021 period, this difference was 511 and 432 basis points as a simple and weighted average, respectively
- While there are various drivers of this outperformance, the largest driver appears to be revenue effects (mainly driven by demand being higher than forecast). Forecast interest expense had a large positive impact on the RoRE in the early years, but this gap has since reduced, contributing to a narrowing margin between allowed returns on equity and actual RoRE. TNSPs spending more on capex than forecast had a large negative effect on the RoRE.

Our key focus area findings include:

- Overall, the COVID-19 response appears to have had a limited aggregate impact on gas consumption and DNSP revenue and expenditure. In our view, this demonstrates the ablility of gas NSPs providing an essential service and operating under a stable regulatory regime to withstand this type of economic shock.
- The weighted average remaining lives of NSPs' existing regulated assets show that most gas networks have relatively long remaining lives – higher than the mid-point of the standard asset life of pipelines, mains and services. These asset classes represent the highest proportion of the existing capital base value (83–94% for DNSPs and 74–87% for TNSPs) and have standard asset lives of between 50–80 years.

# 2 Scope and context for this year's report

This is the second annual gas network performance report. These reports only focus on fully regulated gas NSPs for which we set reference tariffs (prices). While our first gas network performance report only covered DNSPs, this report also covers TNSPs.

This network performance report covers network data for regulatory year 2021, which is:

- 1 July 2020 to 30 June 2021 for Evoenergy Gas, JGN, AGN (SA), Amadeus Gas Pipeline (Amadeus), and RBP.
- 1 January 2021 to 31 December 2021 for AGN (Albury & Victoria), AusNet Gas, Multinet Gas and VTS.

This report does not cover gas pipelines that are unregulated or face only light regulation. See our State of the Energy Market report for a description of light regulation, Part 23 regulation and a geographical map of different gas pipelines in the eastern states of Australia.[1]

## 2.1 Focus areas

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

Our focus areas in 2022 are:

- Introducing the RoRE for gas NSPs (section 6)
- The impact of COVID-19 on gas demand (section 7)
- Changes in asset age profiles over time (section 8)

In developing this report, we engaged with stakeholders to test their views on focus areas. Consumer groups expressed interest in investigating how NSPs are prepared for a low emissions future. While we were unable to consider this topic in depth for this year's report, we are proposing to include it as a focus area in 2023 (see section 9).

Exploring new focus areas each year should help our reports to reflect important emerging issues of stakeholder interest. To best target our focus, we encourage direct feedback on future topics, including the topics identified in section 9.

## 2.2 Stakeholder engagement on this report

Before we developed our first network performance report, we undertook extensive stakeholder engagement in:

1 AER, *State of the Energy Market report*, 2022, pp. 158, 162–163.

- Developing our priorities and objectives for reporting on network performance[2], also set out in Appendix A.
- Completing our profitability measures review, which has been an important input into our network performance reports.[3]

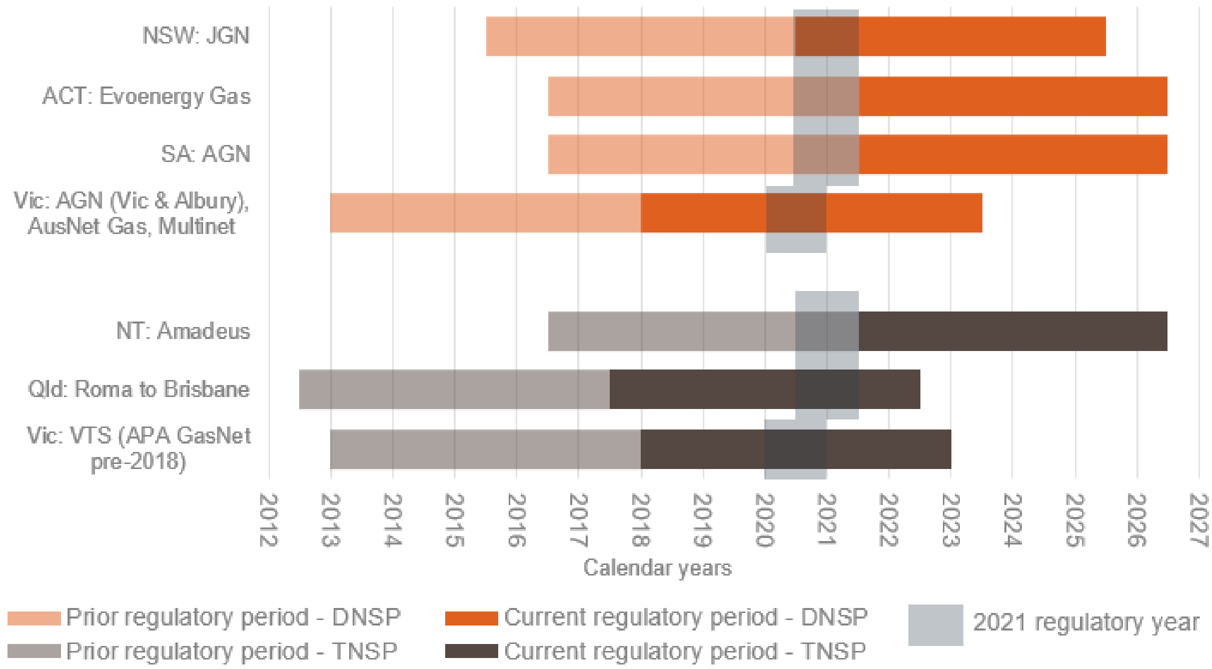
In developing this report, we:

- 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 NSPs an opportunity to review the accuracy of our key data sources.
- Gave NSPs, consumer representatives and other relevant stakeholders an opportunity to review and engage with our analysis.

## 2.3 Where 2021 sits in the regulatory cycle

Generally, our regulatory determinations apply over five years. We also make these decisions in a staggered cycle. Due to this, changes in regulatory approaches or market conditions feed into access arrangements gradually.

**Figure 2-1 The staggered revenue decision timetable**




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

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

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

## 2.4 Data sources for this report

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.

# 3 Characteristics of fully regulated gas NSPs

Fully regulated gas NSPs in Australia transport gas from upstream producers to energy users. Table 3-1 highlights the differences in transmission and distribution.

**Table 3-1 Gas pipeline services in this report**

| | | |
|---|---|---|
| **Distribution** | Urban and regional distribution networks, which are clusters of smaller pipes or mains that transport gas to customers in local communities.<br>Fully regulated services are called haulage reference services, although this report refers to them as ‘reference services’ for simplicity. | Providers of haulage reference services:<br>• JGN in NSW<br>• Evoenergy Gas in ACT<br>• AGN in South Australia (SA)<br>• Multinet Gas in Victoria<br>• AusNet Services in Victoria<br>• 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 TNSPs transport gas to many industrial customers through a direct connection.<br>Fully regulated services are called reference services. | Providers of reference services:<br>• Amadeus in the Northern Territory<br>• RBP in Queensland<br>• VTS in Victoria |

We apply full regulation to three gas TNSPs. Like the DNSPs, the TNSPs provide reference services under an access arrangement and are subject to a price cap and an approved annual tariff variation mechanism (for more information on price caps, see Section 4.1.1).

An analysis of the relative characteristics of gas TNSPs and DNSPs provides important background for understanding network performance and the effectiveness of the regulatory framework. These differences affect the outcomes discussed in the following chapters, including revenue, expenditure, and network service outputs.

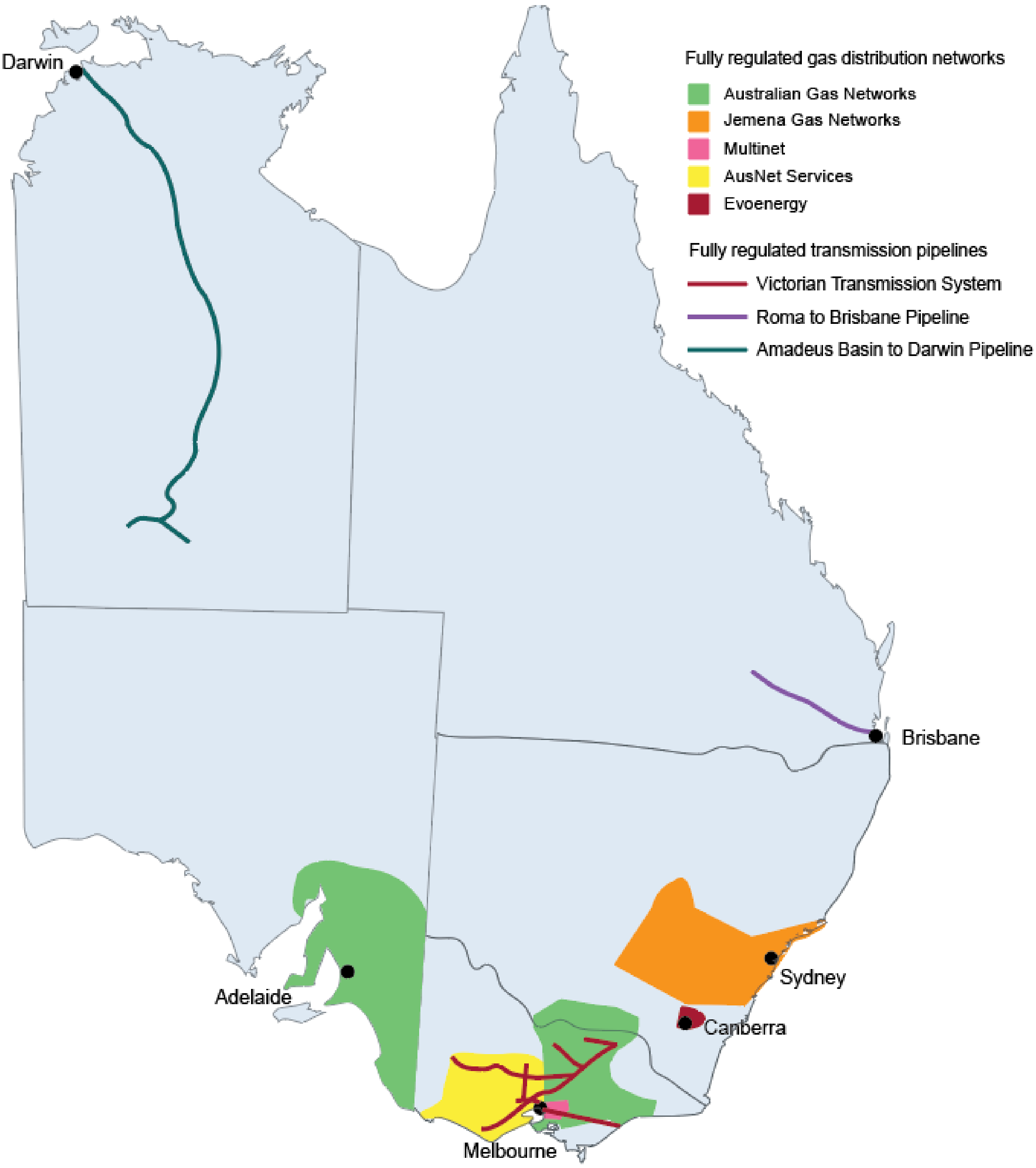
Our key findings are that:

- The DNSP customer base has consistently been over 97% residential and less than 0.04% industrial since 2011. However, a sizeable proportion of the gas that DNSPs 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 three of the six DNSPs (as well as directly to other large customers), which may reflect why many of its performance trends discussed throughout this report more closely reflect what we see in the DNSPs.
- Distribution pipeline length has been increasing since 2011 to accommodate growth in connections. Transmission network length has remained relatively steady and more closely reflects the geographic size of the network rather than customer density.
- While the gas that DNSPs deliver has remained fairly steady (and has declined for industrial users), transmission gas withdrawals have increased and are 19.9% higher than in 2012.

## 3.1 The fully regulated gas NSPs

Figure 3-1 highlights where the three fully regulated gas TNSPs and six fully regulated DNSPs operate. Outside of Victoria (where VTS operates), the TNSPs and DNSPs operate in different geographical regions.

**Figure 3-1 The fully regulated gas NSPs**




Source: AER analysis adapted from AER, State of the Energy Market 2022, Figure 5.1.

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

- Amadeus 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.[4] This gas is predominantly used for electricity generation.

- VTS operates in Victoria and supplies gas to industrial and electricity generation customers and to gas DNSPs who supply residential and commercial customers; AGN (Albury and Victoria), Multinet Gas and AusNet Gas. VTS also transports gas to NSW via the Moomba–Sydney Pipeline and to SA via the SEA Gas Pipeline. VTS primarily sources gas from offshore gas fields in the Gippsland, Bass and Otway basins.[5] VTS also transports gas from the Dandenong LNG gas storage facility, Iona underground storage and Cooper Basin.
- 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. RBP transports the gas between the Wallumbilla supply hub, Brisbane, and regional centres along its route.[6] This gas is predominantly used for electricity generation and as a feedstock in industrial activity but is also supplied to eastbound retail customers and westbound for trading.

## 3.2 Transmission relative to distribution pipeline characteristics

Our inaugural gas network performance report in 2021 discussed the different characteristics of the gas DNSPs we regulate, and how these differences influence the prices charged for reference services. Given we have expanded our report this year to include TNSPs, this section focuses on how the characteristics of the three fully regulated gas TNSPs differ from the fully regulated gas DNSPs with respect to length, pressure, materials, customer types and gas delivered.

There are also some differences in the data we received from TNSPs and DNSPs:

- The data that TNSPs and DNSPs are required to provide through regulatory reporting can differ. For example, only DNSPs report on UAFG and network outages. There can be various drivers of these reporting differences, including whether measures have been required for jurisdictional regulations and whether they are mainly relevant for residential customers (and therefore more relevant for DNSPs).
- The level of confidentiality in the data provided can differ. Because TNSPs have fewer customers, this increases the likelihood of some data being confidential. For instance, we do not report actual revenue for Amadeus given it has a single customer, which also limits other measures we can report for Amadeus.
- In some instances, the quality of the data can differ. For instance, because this is the first time we are reporting on gas transmission performance, we have faced more data challenges for TNSPs than we have for DNSPs. We will work with the gas TNSPs to

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

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

6 AEMC, *QLD: Roma Brisbane Pipeline*, AEMC, 2022, accessed 31 August 2022.

improve the data we collect and how we use it. We consider the release of this report to be a positive step in that direction.

### 3.2.1 Network length

Route length has remained steady over time, with VTS and Amadeus reporting no change to route length, and RBP reporting only 0.6% growth in route length over the ten-year reporting period. Pipeline length only differs to route length for VTS – which had 13.5% growth in pipeline length in 2017. Steady route length (and typically steady pipeline length) reflects that transmission networks have a small number of high-pressure pipelines that carry gas from producing basins to major population centres and a small number of large customers (power stations and large plant).

In contrast, distribution pipeline length has been increasing just over 1% annually since 2011 to accommodate growth in connections. This increasing length reflects that gas distribution networks comprise of clusters of smaller pipes or mains that progressively extend to connect more customers. As such, the length of distribution networks reflects customer density as well as the geographical size of the network.

### 3.2.2 Pressure type

Typically, transmission pipelines operate between 10,000 and 15,000 kPAs.[7]

In contrast, most of the gas distribution networks comprise of medium (7 to 1,050 kPa) and high (>1,050 kPa) pressure mains. Gas DNSPs also have some low (≤7 kPa) pressure mains and assets operating at sufficiently high pressure to be classified as transmission pipelines. Pressure distribution varies materially between gas DNSPs, with NSW/ACT networks being primarily medium pressure, Victorian networks being primarily high pressure and the SA network having a greater mix of high and medium pressure mains.

Low pressure pipelines have been decreasing in Victoria and SA, which reflects major programs to replace low-pressure cast iron pipes.[8] For a detailed discussion on distribution network pressure types, see our previous year's gas network performance report.[9]

### 3.2.3 Material types

Gas transmission networks mostly rely on steel pipelines.[10]

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

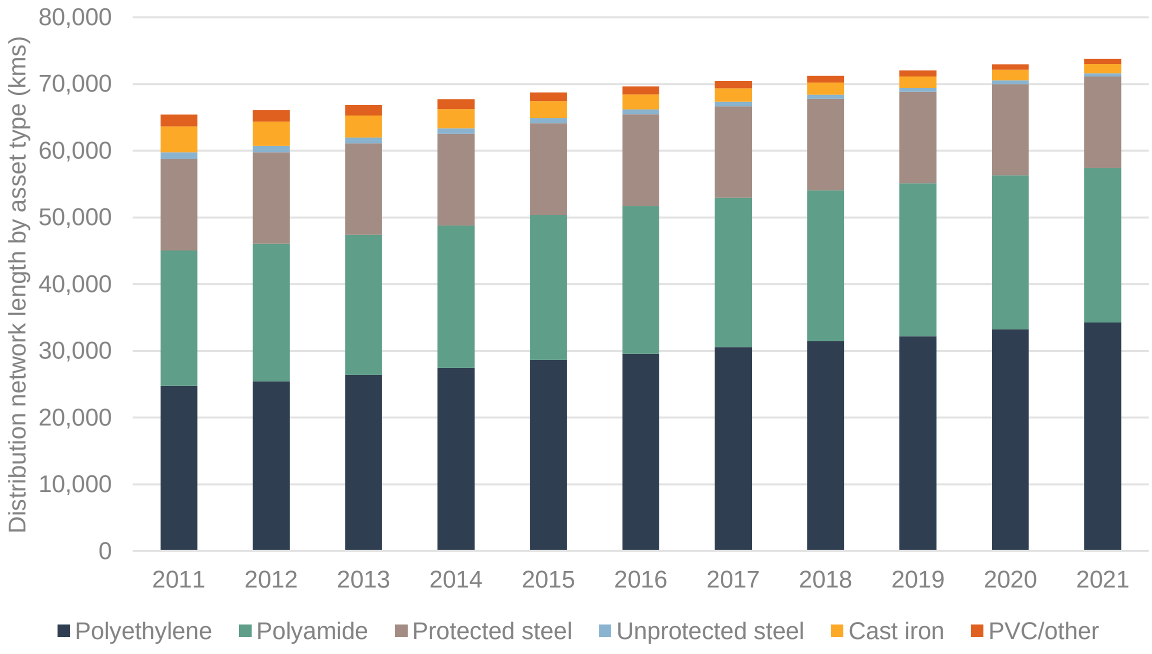
8 AGN, *Final plan: Access arrangement information for our Victorian and Albury natural gas distribution networks: 2018 to 2022*, December 2016, pp. 81–82; AusNet Services, *Gas access arrangement review 2018-2022: Access arrangement information*, December 2016, p. 100; Multinet Gas, *2018 to 2022 access arrangement information*, December 2016, p. 56; AGN, *Access arrangement information for AGN's SA natural gas distribution network*, July 2015, p. 133.

9 AER, *Gas network performance report*, December 2021, section 3.2.1, pp. 15–19.

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

In contrast, gas distribution networks include varying proportions of pipelines of different materials, including polyethylene, polyamide, steel, protected steel (with polyethylene coating), cast iron, PVC and other materials.

**Figure 3-2 Network length by asset type – DNSPs**




Source: Annual RINs table n2.1 – network characteristics – network length by pressure and asset type, AER analysis.

Since 2011, distribution networks have increasingly included plastic (polyethylene and polyamide) pipes, and less steel and cast iron pipes. The Victorian DNSPs and AGN (SA) use polyethylene in their networks, whilst JGN and Evoenergy Gas mostly use polyamide, with smaller amounts of polyethylene. These materials enable gas DNSPs to transport gas at predominately medium or high pressure. They are also relatively easy to install, cost effective and resistant to damage from corrosion or the effects of gas.

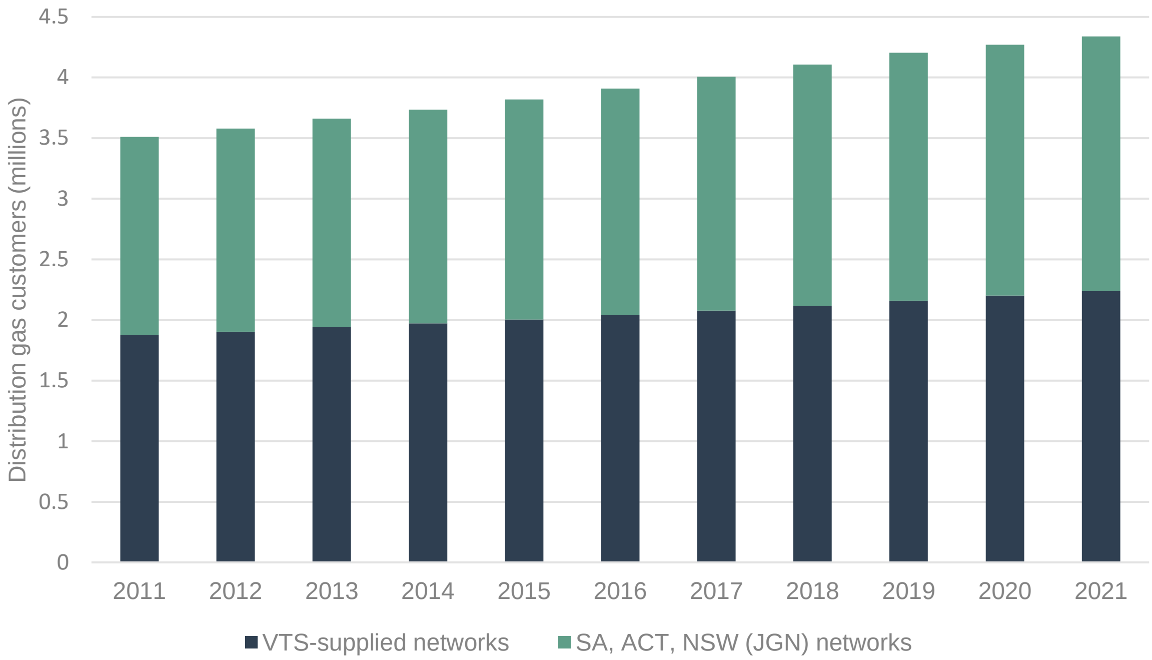
AusNet Gas and Multinet Gas are the only DNSPs with over 40 km of unprotected steel in their networks in the 2021 regulatory year. Unprotected steel mains and service lines are prone to corrosion and AusNet Gas and Multinet Gas are running major programs to replace their unprotected steel mains to reduce the risk of gas leakage. We discuss the implications of these programs on expenditure and asset age profiles in sections 4.2 and 8 respectively.

### 3.2.4 Customer types

Gas TNSPs report very few customers. These include gas powered generators (Amadeus and RBP serve two, and VTS serve six). These also include large industrial gas users that are connected directly to the transmission network and use gas as a feedstock in the large-scale production of goods and services. Amadeus serves no customers other than generators and RBP's other customer numbers are confidential.

VTS has the larger customer base of the gas TNSPs. As well as serving six gas powered generators, it also provides 58 customers with reference services and supplies gas to the three fully-regulated gas distribution networks in Victoria – AGN (Albury and Victoria), Multinet Gas and AusNet Gas (see Figure 3-3).

**Figure 3-3 Distribution gas customers by whether the network is directly VTS-supplied**




Source: Annual RINs sheet s1.1 - customer numbers by customer type. AER analysis.

The DNSP customer base has been steadily growing from just over 3.5 million in 2011 to just over 4.3 million customers in 2021. This customer base has consistently been over 97% residential and less than 0.04% industrial since 2011. In 2021, the DNSP customer base was about 2.5% commercial. Despite the high proportion of residential customers, Figure 3-4 shows that a sizeable proportion of the gas delivered goes to commercial and industrial customers.

**Figure 3-4 Gas delivered by customer type – DNSPs (PJs)**


Source: Annual RINs table n1.1 – demand by customer type, AER analysis.

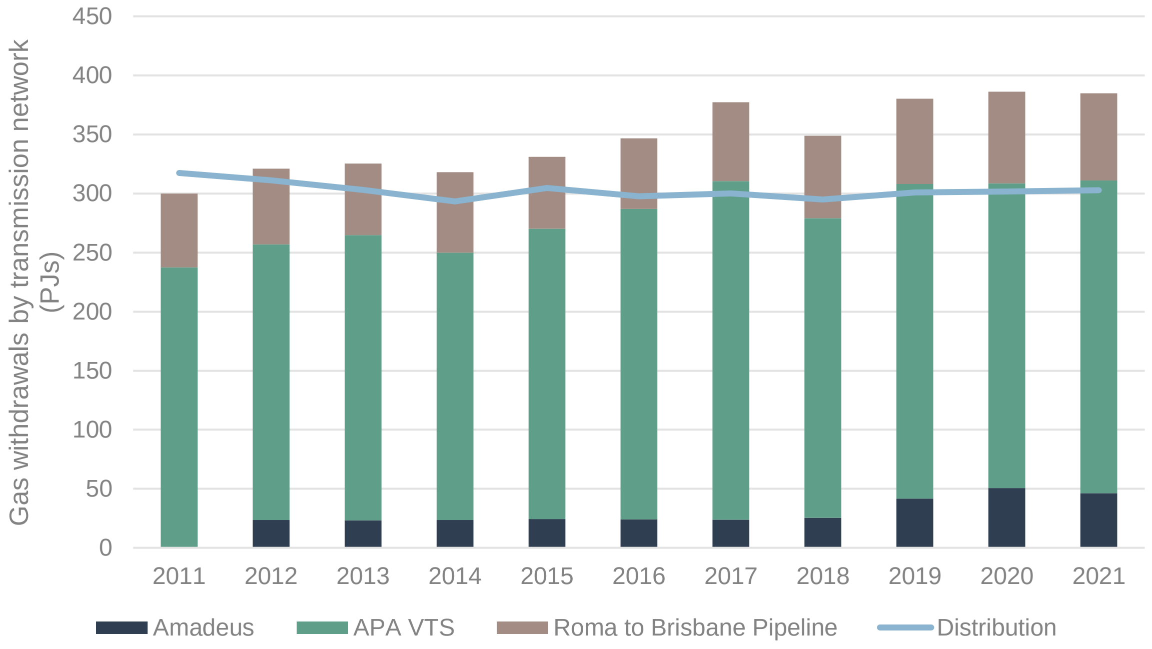
For details on differences in gas distribution customers between jurisdictions, see our previous gas network performance report.[11]

### 3.2.5 Gas delivered

Gas withdrawals at the transmission level tend to be greater than gas delivered at the distribution level (Figure 3-5). In part, this reflects the large quantities of gas used by industrial and generation customers and that the gas delivered by several DNSPs was also withdrawn from VTS.

**Figure 3-5 Gas delivered by each TNSP or DNSPs (PJs)**

11 AER, *Gas network performance report*, December 2021, section 3.3, pp. 22–26.




Source: Annual RINs sheets: n1.3.2 annual volume gas withdrawals, n1.a demand by customer type. AER analysis.

**Figure 3-5 also shows how the amount of gas delivered has changed over time, with**

Table 3-2 summarising the key metrics. Gas delivered at the transmission and distribution level increased slightly over 2021. However, gas delivered to distribution customers has decreased overall since 2011 – albeit only by 4.6%. In contrast, gas withdrawals at the transmission level have increased on average and are 19.9% higher than in 2012 (our first data point for Amadeus).

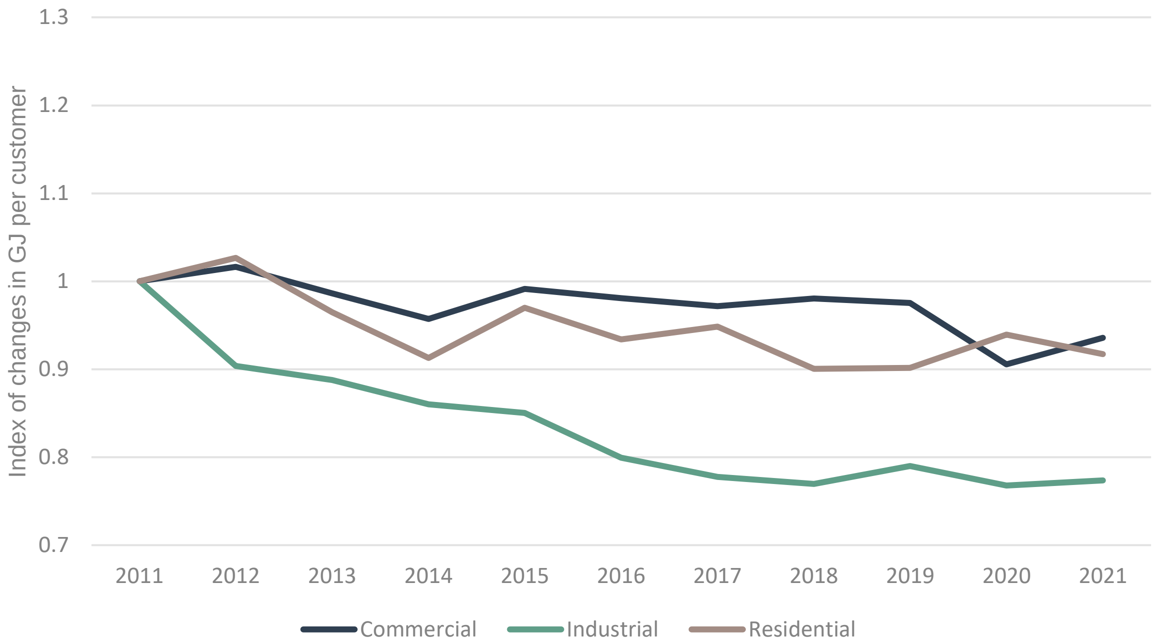
**Table 3-2 Key metrics – changes in gas delivered**

| Measure | Transmission | Distribution |
|---|---|---|
| Gas delivered in 2021 | 384.9 TJs | 302.7 TJs |
| Change over last year | -0.3% | 0.3% |
| Change since max | -0.3% (2020) | -4.6% (2011) |
| Change since 2012 | 19.9% | -2.7% |

Source: Annual reporting RIN sheets: n1.3.2 annual volume gas withdrawals, n1.a demand by customer type. AER analysis.

While gas delivered at the distribution level is 4.6% lower than at its maximum in 2011, reduced consumption from DNSPs has been met with a steadily increasing customer base. This results in a more notable decline in gas delivered on a per customer basis. As Figure 3-6 illustrates, gas consumed per distribution customer is decreasing across the customer base, but is largest for industrial customers.

**Figure 3-6 Gas delivered per customer – by customer type since 2011 – DNSPs (GJs)**




Source: Annual RINs sheets: s1.1 – customer numbers by customer type, n1.1 – demand by customer type. AER calculation of gas delivered for each customer type using 2011 as a base.

We will continue to monitor these movements in future reporting years and may investigate the drivers in more detail.

### 3.2.6 Network capacity

Unlike DNSPs, TNSPs report network capacity. Table 3-3 shows how the capacity of each TNSP has changed since the previous year. Amadeus and RBP are small networks that undertake network augmentation infrequently– and therefore report few instances of material capacity increases. For instance:

- RBP's capacity grew 54% in 2016 after becoming bi-directional, which included connecting to the Wallumbilla Hub and installing metering equipment to enable measuring bi-directional gas flows.[12]
- Amadeus's capacity grew 38% in 2019 after it responded to pressure constraints after adding demand points at Warrego and Tanami.[13]

12 APA Group, *Roma to Brisbane Pipeline access arrangement submission: Attachment 5-1 – historic capital expenditure project documents*, September 2016, pp. 43–48.

13 APA Group, *Annual RIN – Amadeus Gas Pipeline: RIN response and basis of preparation 2020*, November 2020, pp. 48–49.

In contrast, the capacity of VTS increased between 2014–17 to transport additional gas between NSW and Victoria.

**Table 3-3: Changes in TNSP network capacity since prior year (%)**

| Network capacity | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|---|---|---|
| Amadeus | | | | | | | 38 | | |
| VTS | -1% | 1 | 8 | 2 | 3 | 2 | 1 | | 1 |
| RBP | 6% | | | 54 | | -6 | | | |

Source: Operational performance data sourced Annual Revenue RINs n2.2 network characteristics – network capacity by pipeline, AER analysis.

### 3.2.7 Revenue from non-reference services

Forecast and actual revenues in this report also include revenue from non-reference services. This reflects that after we use the building block approach to determine an NSP's economically efficient revenue, that revenue is allocated between reference and other services based on relative costs.[14]

This factor does not materially change our analysis, as reference prices influence the price that NSPs can charge for non-reference services. This is because NSPs must make at least one reference service available, which also serves as a benchmark for the price of other pipeline services.[15]

However, this factor results in some differences between TNSPs and DNSPs. DNSPs 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, TNSPs (particularly Amadeus and RBP) provide a higher proportion of non-reference services. This higher proportion of non-reference services can make it more difficult to forecast revenues for Amadeus and RBP.

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

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

# 4 Summary of operational performance in 2021

This section looks at the following core performance outcomes:

- network revenue—the cost to consumers of network services (section 4.1)
- network expenditure (section 4.2)
- capital bases (section 4.3)
- network service outputs (section 4.4).

Unless otherwise stated, all values are presented in real 2021 dollar terms to enable comparisons over time.

We also focus on:

- how outcomes in 2021 relate to longer term trends across network performance measures
- where relevant, how those outcomes compare to forecast amounts.

This section does not directly investigate whether the relationship between network expenditure and service outputs is productively efficient. Rather, this report explores the costs and profitability of providing core regulated services, which reflects a combination of NSPs' productive efficiency, capital market conditions and our regulatory settings. Regulatory settings include how we forecast expenditure and share the rewards or penalties of network performance between NSPs and consumers.

## 4.1 Revenue collected from customers

After explaining how gas NSPs forecast and collect revenue under the regulatory regime, this section analyses:

- The total revenue gas NSPs have collected from customers through reference services.
- The major drivers of this revenue, being building block revenue forecasts and demand.

### 4.1.1 Revenue under the price cap form of control

All fully regulated gas NSPs' reference services are regulated under a price cap form of control.

This begins with establishing a building block revenue forecast.[16] Then, having regard to forecast demand over the access arrangement period, we convert this building block revenue forecast into:

[16] The process for establishing a building block forecast also applies to revenue caps. Revenue caps are the form of control that applies to electricity NSPs. Details on revenue caps are provided on the AEMC's network regulation webpage.

- A set of initial year tariffs
- A series of 'X-factors',[17] 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.

Under price caps, NSPs can earn above or below forecast revenue over time due to changes in demand. If actual demand exceeds forecast, NSPs keep the higher resulting revenue. Similarly, if actual demand is less than forecast revenue, NSPs are exposed to the shortfalls. 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.

The tariffs we set (including the means of varying them annually), along with X-factors and outturn inflation determine the NSP's annual revenue each access arrangement period. However, changes in forecast building blocks remain a key determinant of the costs that customers face.

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 NSPs rather than consumers to demand risk within the access arrangement period. This results in specific strengths and limitations by:

- Incentivising NSPs 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 NSPs to stimulate demand, thereby disincentivising demand management. This has the limitation of misaligning with net-zero objectives, unless the energy source is low carbon (for example, green hydrogen or biogas).

We recently discussed these strengths and weaknesses in our issues paper on 'Regulating gas pipelines under uncertainty'.[18] 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. The AER has been considering issues relating to the form of control for gas NSPs and will consult externally on these matters in 2023 as part of its consultation process on gas access arrangements.

17 The X-factor is used with CPI to smooth the revenue an NSP will collect from customers each regulatory year. This X-factor is an input in the control formula applied to revenues or prices 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 cost of debt.

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

### 4.1.2 Revenue recovered through reference services

Revenue, especially on a per customer basis, is a useful measure of broad trends in the costs of reference services to customers.

However, it is important to interpret this information with caution as this does not perfectly measure the network costs of gas usage for specific customers. This is because:

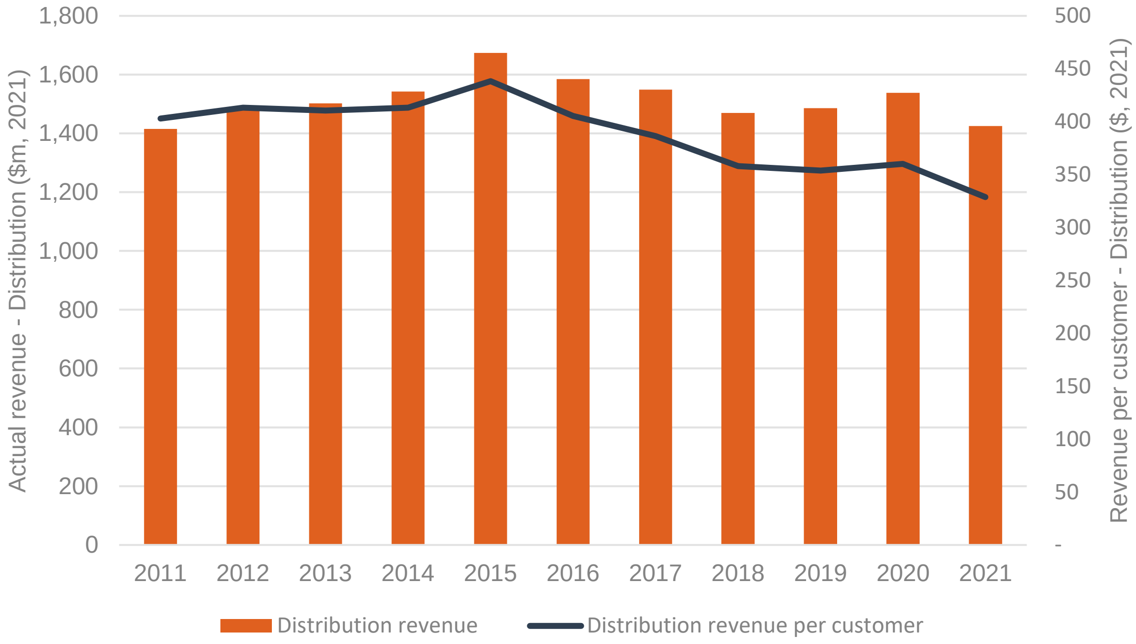
- A customer's gas bill depends on several factors, including their consumption levels as well as network costs.
- NSPs do not collect revenue evenly across customers. For instance, customers who consume large amounts of gas, despite being a small proportion of total customer numbers, provide a relatively high proportion of revenue to NSPs, reflecting their higher usage of reference services. 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.

In 2021:

- While reference service revenue decreased for gas DNSPs by 7.3% since 2020, this was largely driven by a revenue adjustment to JGN to correct for previous overcompensation.
- Reference service revenue increased for VTS by 11.0% and RBP fell by 7.8% since 2020. Revenue remains lower than the peaks experienced in 2012 and 2017. While revenue movements for RBP were relatively smooth over 2011–2021, VTS's revenue generally varied along with the Victorian gas DNSPs, reflecting their common revenue drivers.

Figure 4-1 shows how gas DNSPs' revenue has changed over time, both on a total and per customer basis across residential, commercial and industrial customers.

**Figure 4-1 Total and per customer reference service revenue – DNSPs**




Source: Operational performance data – Distribution, sourced from Annual RINs – S3.1 Reference services and Annual RINs – S1.1 Customer numbers by customer type. AER calculation to convert into $2021 terms and to calculate revenue per customer as reference service revenue ÷ customer numbers.

Figure 4-1 shows that in 2021, reference service revenue decreased for DNSPs by 7.3% since 2020 and was the lowest it has been since 2011. This revenue decline is stark on a per customer basis given distribution customer numbers have been steadily growing by about 2.0% annually since 2011. In 2021, DNSP revenue was $329 per customer compared to $438 per customer at its peak in 2015.

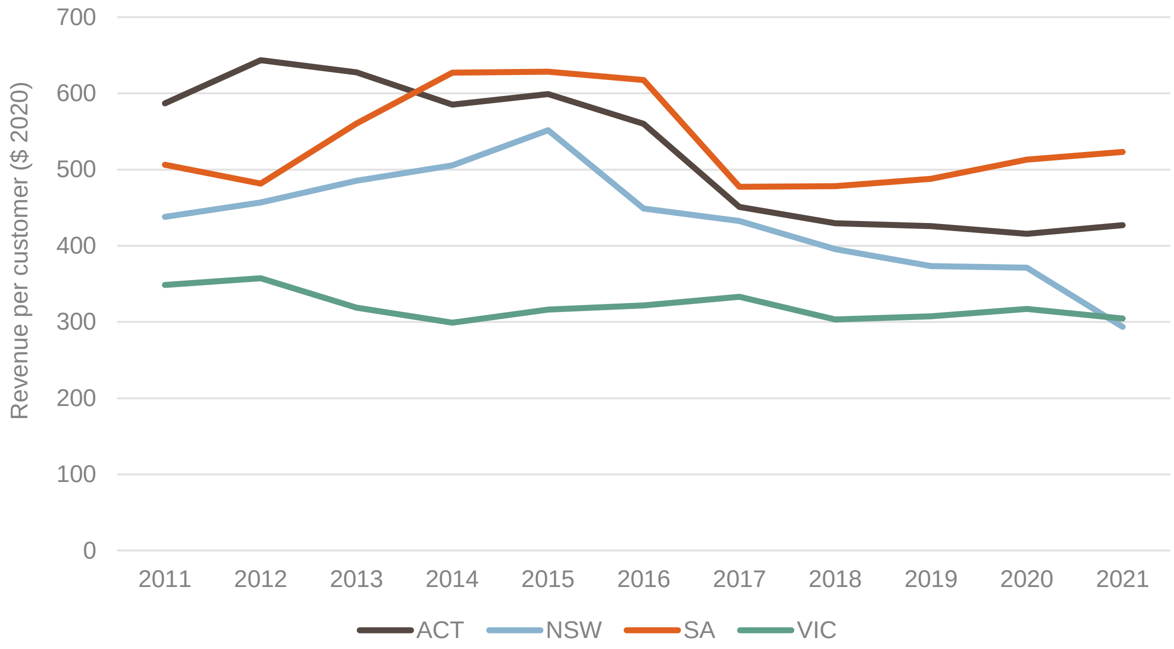
However, Figure 4-2 highlights that the notable decrease in revenue per customer in 2021 was largely driven by the NSW DNSP, JGN experiencing a revenue reduction of 19.6%. JGN's revenue reduction is materially influenced by a downward adjustment of $169 million ($ Jun 2020) over its 2020–25 access arrangement period to correct for an overcompensation provided to it previously.[19] This lower revenue reflects a temporary correction rather than a permanent efficiency gain. However, JGN's revenue reduction in 2021 had other drivers, including the 2018 rate of return instrument coming into effect for JGN that year.[20]

Outside of NSW, revenue per customer decreased slightly for Victorian DNSPs and increased slightly in the ACT and SA. Revenue per customer reductions in Victoria were driven both by lower revenue and customer growth. Revenue per customer increases in the ACT and SA were driven by revenue increases exceeding customer growth (which was still positive).

19 See the explanatory box on 'JGN's revenue growth' in Section 4.1.4 for more on the origin and effect of the previous overcompensation. Further details on the revenue adjustment area also provided in AER, *Gas network performance report*, December 2021, pp. 38–40.

20 The 2018 rate of return instrument comes into effect for ACT and SA DNSPs in the 2022 regulatory year and for the Victorian DNSPs in the 2023 regulatory year. JGN had a lower return on equity in 2021, noting that the equity beta under the 2018 rate of return instrument is 0.6, rather than the equity beta of 0.7 applied previously. See AER, *Rate of return instrument 2018*, Accessed 2 November 2022.

### Figure 4-2 Total reference service revenue per customer by state/jurisdiction – DNSPs



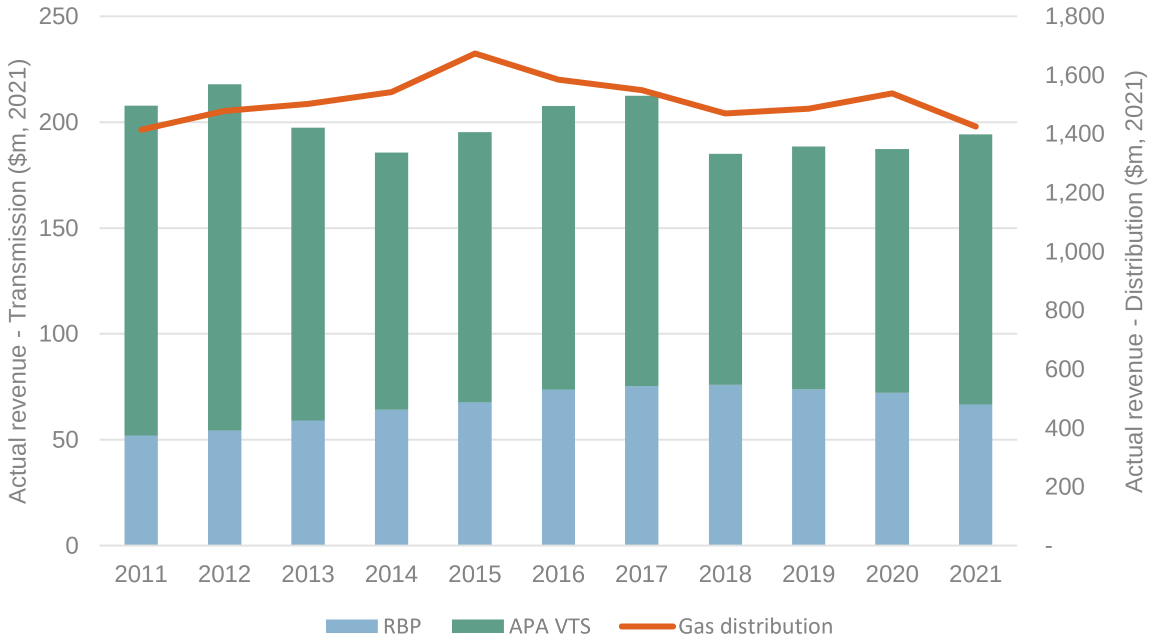

Source: Operational performance data – Distribution, sourced from Annual RINs – S3.1 Reference services and Annual RINs – S1.1 Customer numbers by customer type. AER calculation to convert into $2021 terms and to calculate revenue for each state/jurisdiction ÷ number of customers for each state/jurisdiction.

We do not report revenue per customer for TNSPs. Gas TNSPs typically service a small number of large industrial and electricity generation customers, such that per customer metrics provide poor information on relative performance.

Figure 4-3 shows how RBP's and VTS's total regulated revenue has changed over time. It does not include Amadeus's revenue due to confidentiality. Figure 4-3 also includes a secondary axis to show how these movements in transmission revenue have compared to movements in distribution revenue since 2011. In contrast to DNSPs, revenue for RBP and VTS increased in 2021, rising 3.7% since 2020. However, revenue for these TNSPs in 2021 was still lower than the peaks reached in 2012 and 2017 of $218 million and $212 million.

Figure 4-3 also shows that RBP had smooth revenue changes. In contrast, VTS's revenue has been more variable.

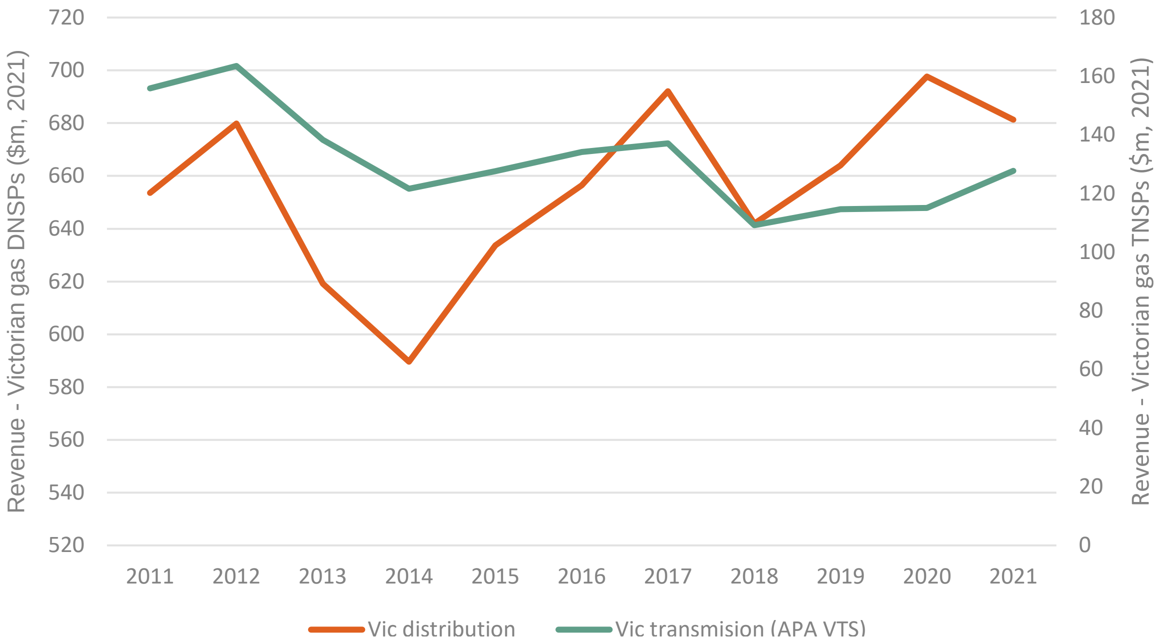
## Figure 4-3 Total reference service revenue – RBP, VTS, DNSPs




Source: Operational performance data – Transmission, sourced from annual RINs – S3.1 Reference services. Excludes Amadeus due to confidentiality. AER calculation to convert to $2021.

While the variation in VTS's revenue does not immediately follow an obvious pattern, Figure 4-4 shows that directional changes in its revenue show a weak positive correlation with the Victorian gas DNSPs. In contrast to Amadeus and RBP, which exclusively serve large industrial and generation customers, VTS also serves the gas distribution networks: AGN (Albury and Victoria), AusNet (gas) and Multinet Gas. As such, many of the revenue drivers affecting these gas DNSPs, such as variations in demand, will also affect VTS.

## Figure 4-4 Reference service revenue in Victoria – Transmission and distribution



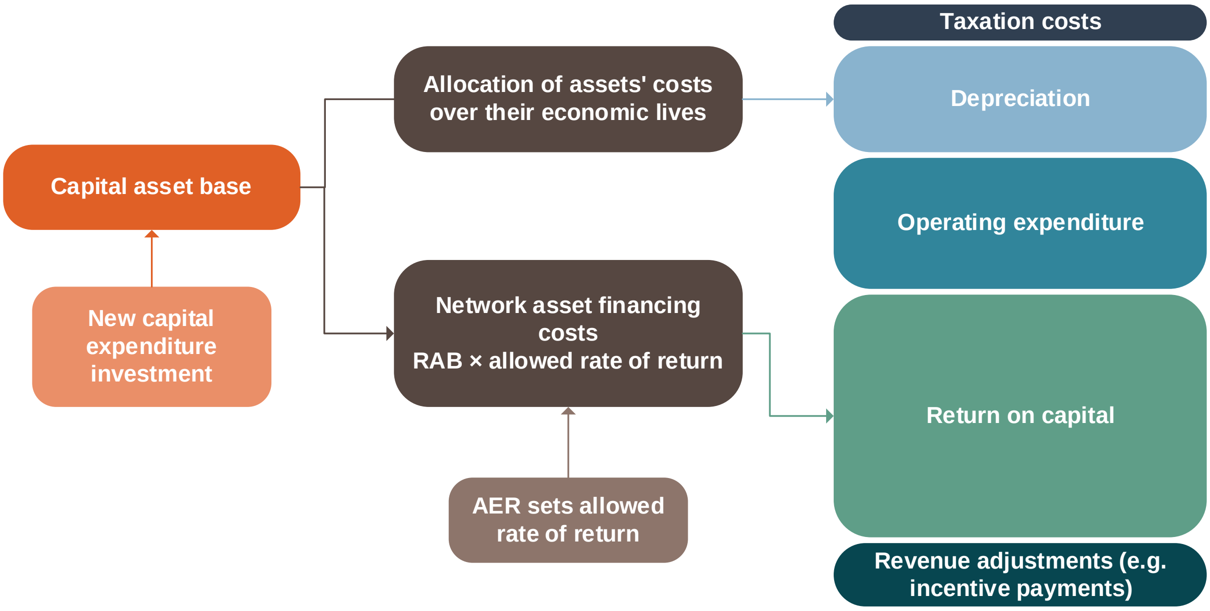

Source: Operational performance data – Transmission, sourced from annual RINs – S3.1 Reference services. AER calculation to convert to $2021.

### 4.1.3 Building block revenue forecasts

All fully regulated gas NSPs 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 gas NSP would require to provide reference services. These include:

- A return on the capital base (or return on capital, to compensate investors for the opportunity cost of funds invested in the NSP).
- Depreciation of the capital base (or return of capital, to return the initial investment to investors over time).
- Forecast capex — the capex incurred in the provision of network 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 depreciation building blocks.
- Forecast operating expenditure (opex) — the operating, maintenance and other non-capital expenses incurred in the provision of network services.
- The estimated cost of corporate income tax.
- Revenue adjustments, including revenue increments or decrements (that is, any 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 gas NSPs, 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 4-5 The building block model to forecast network revenue**



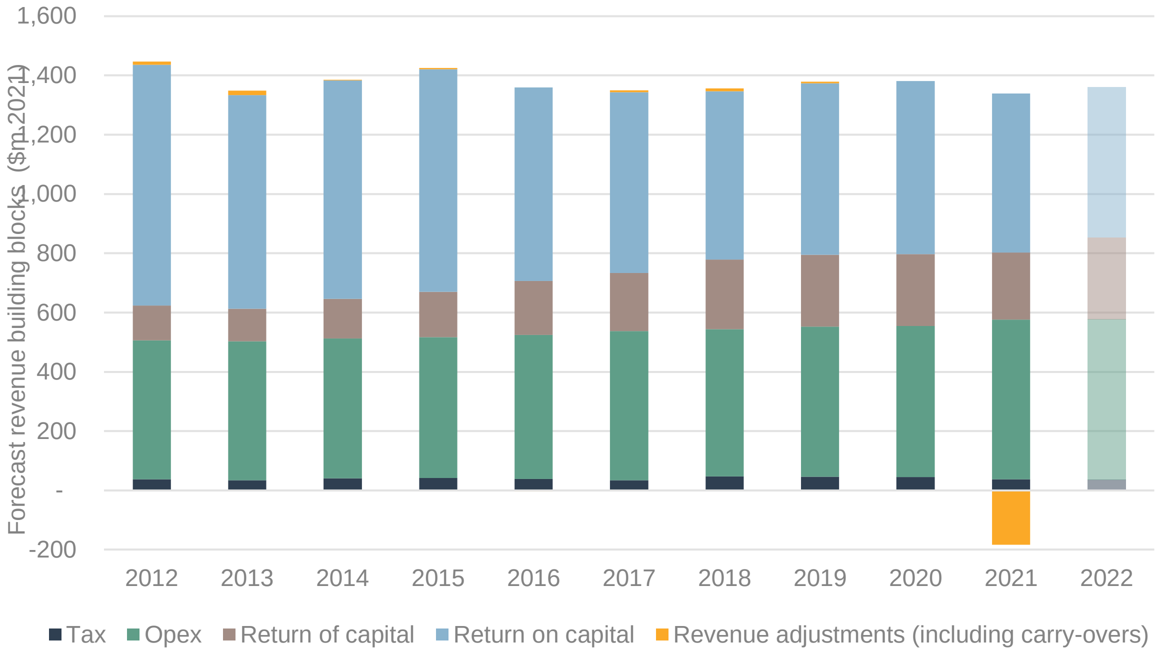

Source: Adapted from AER, State of the Energy Market, December 2018, p.138.

Over 2012 to 2021, we observe:

- Total forecast revenue shows some annual variability. For DNSPs, the aggregate level remained relatively steady. For TNSPs, aggregate forecast revenue trended upwards to reach a peak in 2015, before trending downwards to return to around 2012 levels.
- Under these aggregate outcomes were material changes in specific building blocks:
  - Returns on capital declined (although later in the period for TNSPs), driven by lower forecast rates of return, somewhat offset by growing capital bases.
  - For DNSPs, depreciation increased. This was driven by capital base growth from connections and mains replacement programs in SA and Victoria, and some material investments in assets with shorter economic lives.
  - TNSPs experienced material increases in forecast opex, particularly over 2013–2017. While DNSPs also experienced increases in opex, this was gradual throughout the period and minor relative to other revenue drivers.
  - A large downwards revenue adjustment in 2021 applied to JGN so it could return additional revenue previously provided under an enforceable undertaking while its final access arrangement was undergoing remittal.

Figure 4-6 shows how forecast revenue has changed since 2012 for DNSPs.

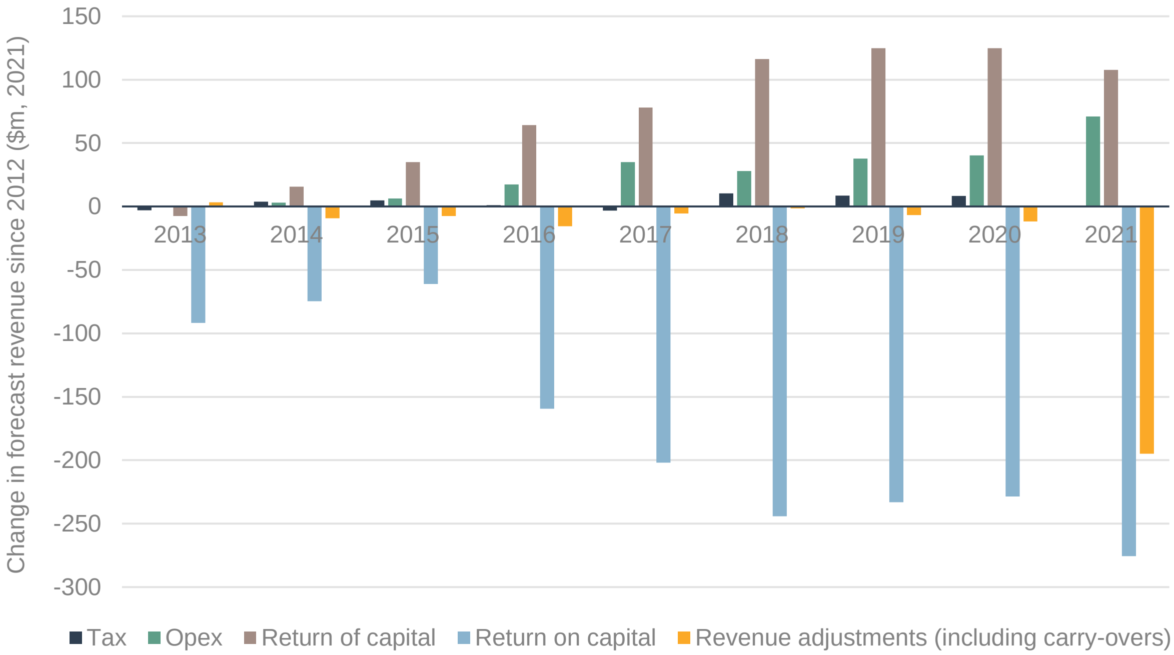
### Figure 4-6 Forecast revenue building blocks – DNSPs




Source: PTRMs 53.01 – Revenue summary – Building block components. AER calculation to convert revenue into $2021 terms.

Figure 4-7 highlights how different building block forecasts have driven these changes.

### Figure 4-7 Change in forecast building blocks since 2012 – DNSPs



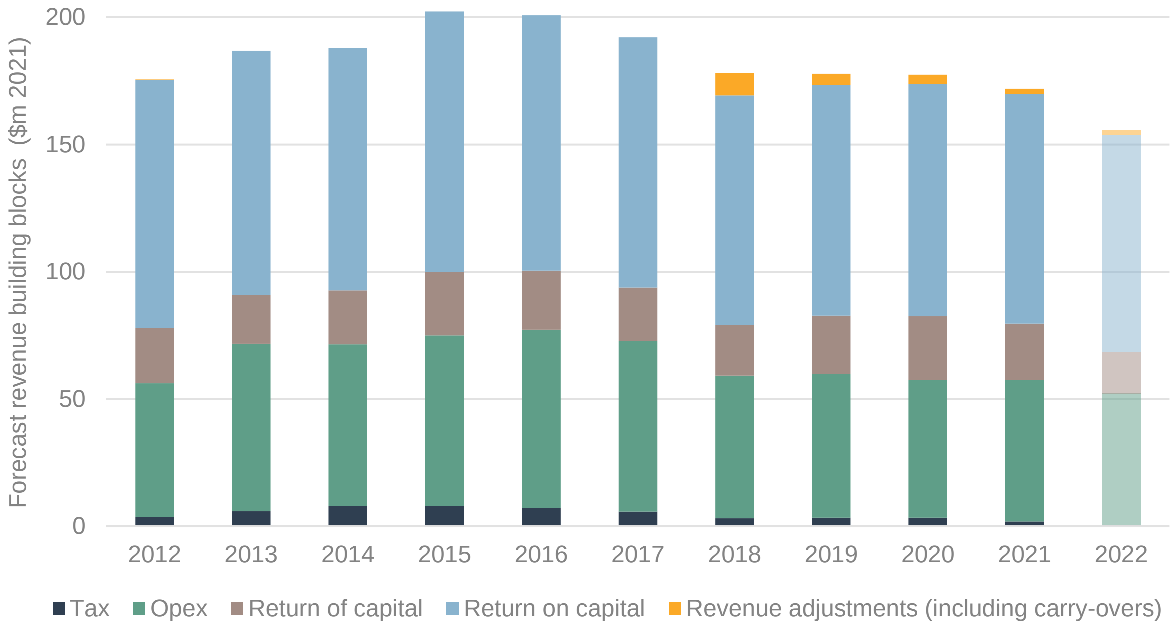

Source: PTRMs 53.01 – Revenue summary – Building block components. AER calculation to convert to $2021 and to calculate the percentage change in revenue per category relative to 2012 as the base year.

Figure 4-7 shows that the major drivers of changes in forecast revenue for DNSPs are:

- Returns on capital decreasing. Returns on capital are driven by the allowed rate of return and the capital base. While capital bases increased (particularly in Victoria and SA), allowed rates of return decreased to have a much larger impact.
- Depreciation (also referred to as the ‘return of capital’) growing. This was driven in large part by material expenditure from JGN on information and communications technology (ICT). ICT has a short economic life (typically five years), meaning that expenditure is recovered by collecting more revenue over a shorter period.
- Gradual increases in forecast opex.
- A one-off downwards revenue adjustment in 2021 to return additional revenue previously provided to JGN under an enforceable undertaking while its final access arrangement was undergoing remittal following limited merits review.

Figure 4-8 shows how forecast revenue has changed since 2012 for TNSPs.

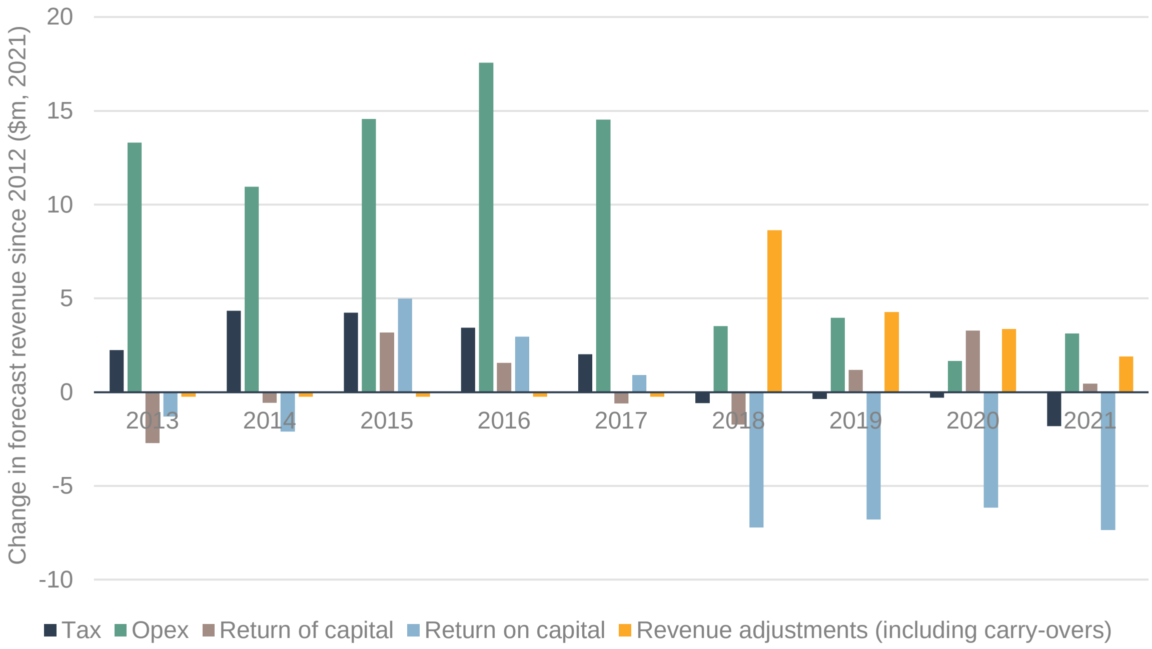
**Figure 4-8 Forecast revenue building blocks – TNSPs**




Source: PTRMs 53.01 – Revenue summary – Building block components. AER calculation to convert revenue into $2021 terms.

Figure 4-9 highlights how different building block forecasts have driven these changes for TNSPs.

**Figure 4-9 Change in forecast building blocks since 2012 – TNSPs**




Source: PTRMs 53.01 – Revenue summary – Building block components. AER calculation to convert to $2021 and to calculate the percentage change in revenue per category relative to 2012 as the base year.

Figure 4-9 highlights the major drivers of changes in forecast revenue since 2013 for TNSPs:

- Returns on capital decreasing, driven by lower rates of return. This building block only materially reduced from 2018 for TNSPs because they were relatively late to have their allowed rates of return reset under the AER's 2013 rate of return guidelines. VTS and RBP only had their allowed returns on debt reset using the historical 'on the day approach' in the 2013 regulatory year, with Amadeus only being reset in the 2012 regulatory year. After the allowed return on debt is reset using the on the day approach, it stays at a constant rate for the next five years. As such, we only saw a clear reduction in the return on capital from 2018 for TNSPs.
- Materially higher opex, particularly over 2013–2017. While DNSPs also experienced increases in opex, this was gradual throughout the entire period and minor relative to other revenue drivers.

Unlike DNSPs, TNSPs did not experience material changes in the return of capital (depreciation). In general, increasing forecast TNSP revenue from 2012–15 was predominately driven by higher forecast opex. Forecast revenue then started decreasing, driven both by lower opex forecasts and lower returns on capital.

In the remainder of this section, we expand on these specific revenue drivers.

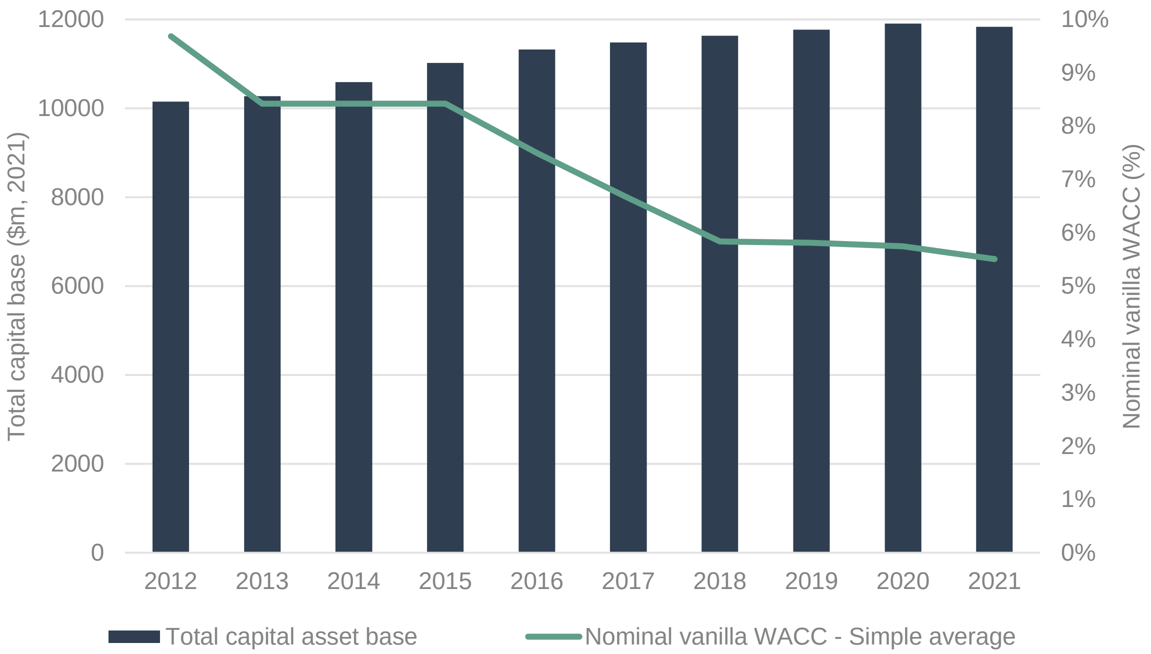
## Declining returns on capital

NSPs are capital intensive businesses. The return on capital is one of two building blocks through which they recover the costs of raising this capital. It 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 required returns on capital in our regulatory decisions. Holding other factors constant, this would reduce overall revenue requirements. However, for DNSPs (and TNSPs on average, due to the augmentation by the largest TNSP, VTS), this has been offset by material growth in capital bases. This growth is due to investment in network assets, which NSPs finance through issuing debt or raising equity. These two effects are set out in Figure 4-10.

**Figure 4-10 Changes in costs of capital compared to capital bases – NSPs**




Source: WACC from PTRMs 51.02. Capital base from operational performance data, sourced from RFMs – Total capital base roll forward – Interim closing capital base where available, and otherwise, annual RINs – F10.1 Capital base values. AER calculation to convert capital base into $2021.

This growth in capital bases also contributes to higher forecast depreciation, which we discuss in the next section. NSP expenditure and investment are analysed further in section 4.2.

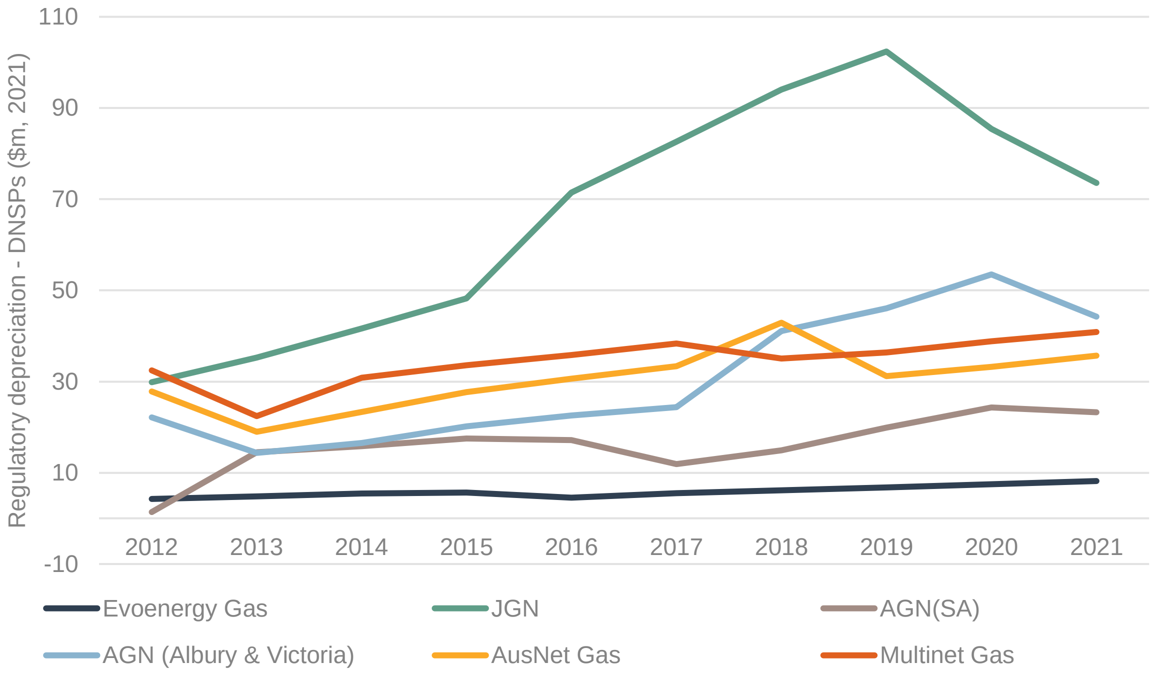
## Growth in forecast depreciation

When network 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. This ensures that over the full economic lives of the assets, NSPs recover revenue equal to the value of the investments.

However, the type of assets being invested in (and the economic life of the assets) affects the rate at which this depreciation occurs, and the resulting impact on revenue in any given access arrangement period. 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 4-11 illustrates forecast regulatory depreciation for DNSPs over 2012–2021.

**Figure 4-11 Growth in the forecast depreciation building block – DNSPs**



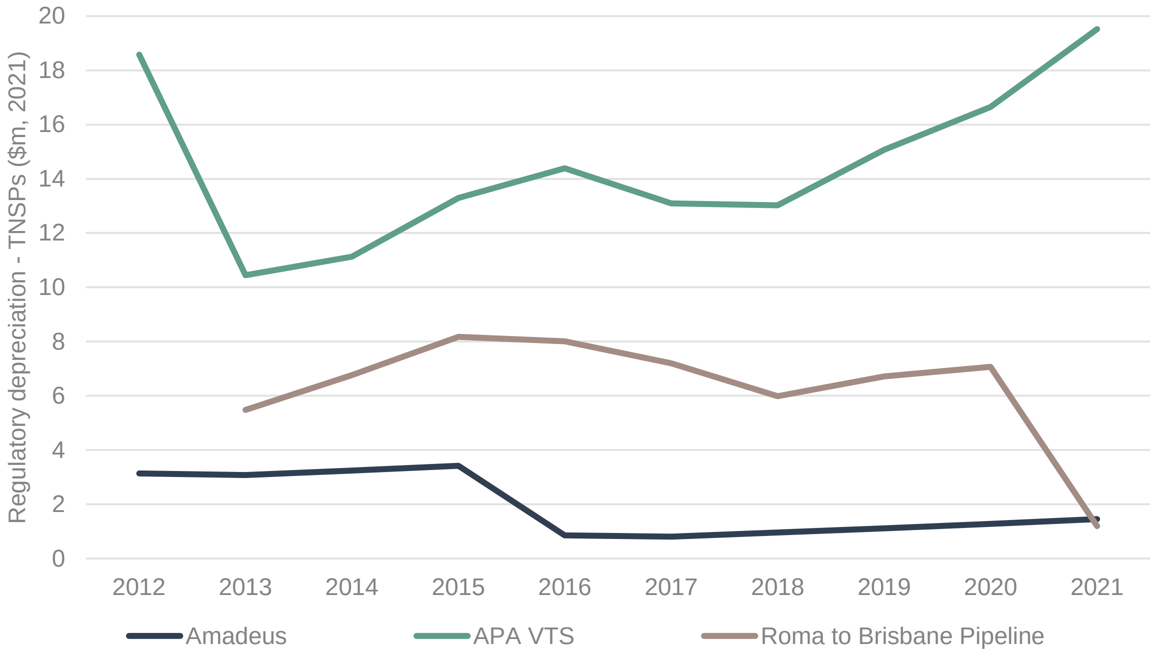

Source: PTRM 53.01 – Revenue summary Building block components – Return of capital and depreciation. AER calculation to convert into $2021.

Due to growing capital bases, forecast regulatory depreciation has increased across all gas DNSPs. Forecast depreciation typically changes gradually because regulated NSPs are comprised largely of long-lived assets, although there can be exceptions. For example, the National Gas Rules enable the AER to accelerate depreciation where necessary to allow cost recovery and generate efficient prices as new information becomes available.[21] There can also be large expenditure on assets with relatively shorty economic lives. For example, JGN's forecast depreciation increased materially over 2012 to 2019 because it had a large program of expenditure on ICT software (approximately $135 million in 2020 dollars). ICT software has an economic life of only five years, so this investment rapidly increased forecast depreciation.

Figure 4-12 illustrates that over 2011–2021, forecast depreciation moved very differently for each gas TNSP.

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

**Figure 4-12  Growth in the forecast depreciation building block – TNSPs**




Source: PTRM 53.01 – Revenue summary  Building block components – Return of capital and depreciation. AER calculation to convert into $2021.

Despite TNSPs comprising largely of long-lived assets, their forecast depreciation is less smooth than what we observe for most DNSPs. 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, or an asset fully depreciates. This lumpiness is also reflected in their capex profiles. For example, while VTS moved similarly to the Victorian DNSPs, its movements were more dramatic.

As another 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.[22]

## 4.1.4 Demand and differences in forecast and actual revenue

This section looks at how actual revenue has diverged from revenue forecasts, and how this relates to outturn demand differing from forecasts

Demand for reference services is a key driver of the revenue that NSPs collect from their customers. Under price caps, gas NSPs are exposed to demand or 'volume-risk'. If demand exceeds forecasts, the NSP keeps the higher resulting revenue. Similarly, if demand is less than forecast, the NSP is exposed to the shortfalls. This incentivises NSPs to develop tariff structures and undertake other activities that encourage utilisation of the network. This also means that

[22] 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.

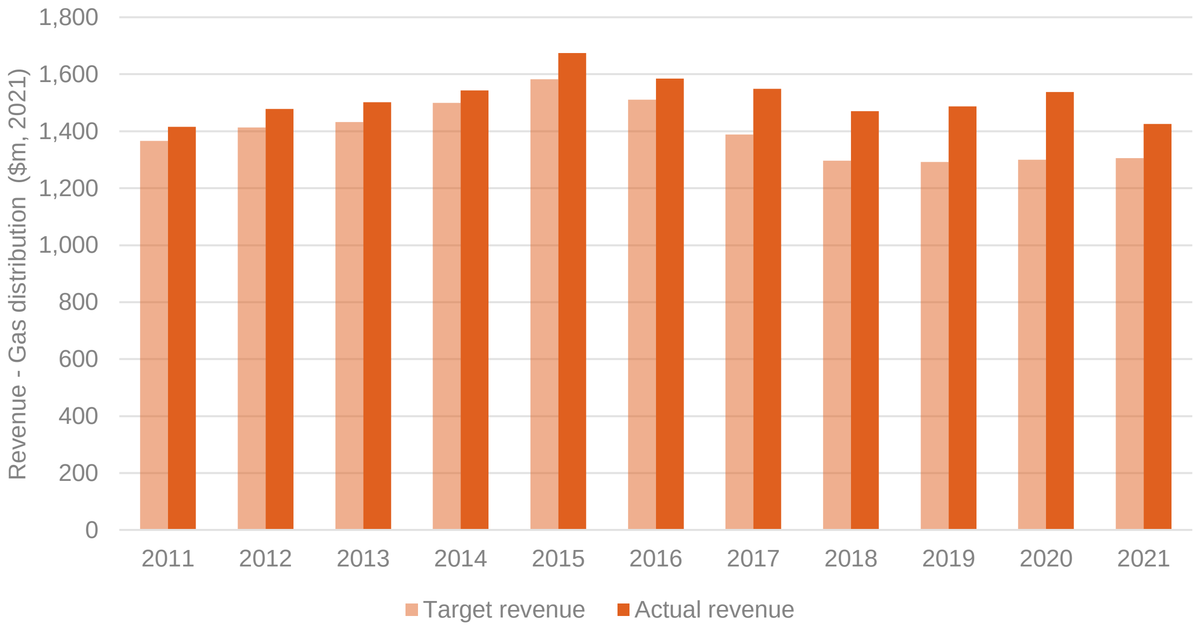
demand forecasting error may contribute to customers paying more revenue than is necessary, or NSPs recovering less revenue than is necessary to efficiently provide reference services.

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. For completeness, 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. Price caps are designed to encourage NSPs 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.

We observe that:

- Since 2011, gas DNSPs in aggregate have consistently recovered revenue above forecast revenue requirements. RBP and VTS also recovered more revenue than forecast since 2011 and have generally over-recovered by a greater margin than DNSPs.
- The difference between forecast and actual revenue has grown larger in recent years for both DNSPs and TNSPs. For DNSPs, this was driven by customer numbers growing faster than forecast.

**Figure 4-13 Reference service revenue compared to forecast revenue – DNSPs**

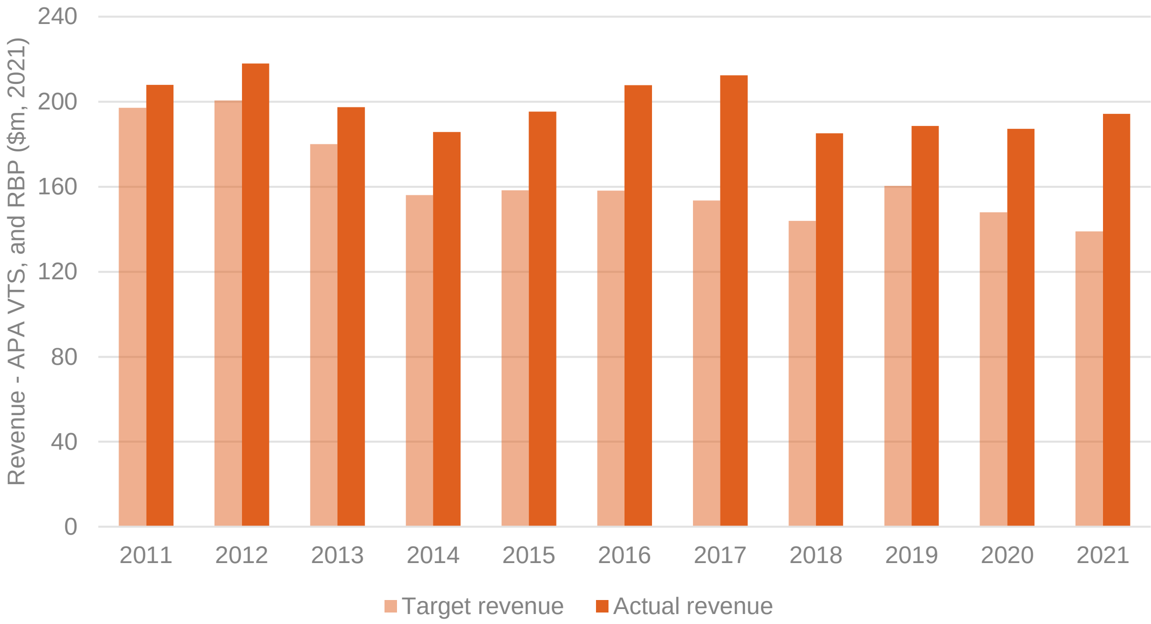



Source: Operational performance data – Distribution. Original sources: Annual RINs – F3.1 Reference services (reference services revenue) and PTRMs – Revenue summary – Building block components (forecast revenue). AER calculation to convert into $2021 terms using actual inflation measured by the consumer price index (forecast inflation is first stripped out from target revenue to present both series on like-for-like terms).

DNSPs 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. This is revenue JGN will return to consumers in the following access arrangement period. If we were to adjust for this impact, revenue outperformance on a DNSP average would still be greater than previous years, although the margin of over-recovery would narrow.

Figure 4-14 compares actual and forecast revenue for two of three gas TNSPs. The third TNSP, Amadeus is not included as its actual revenue is confidential.

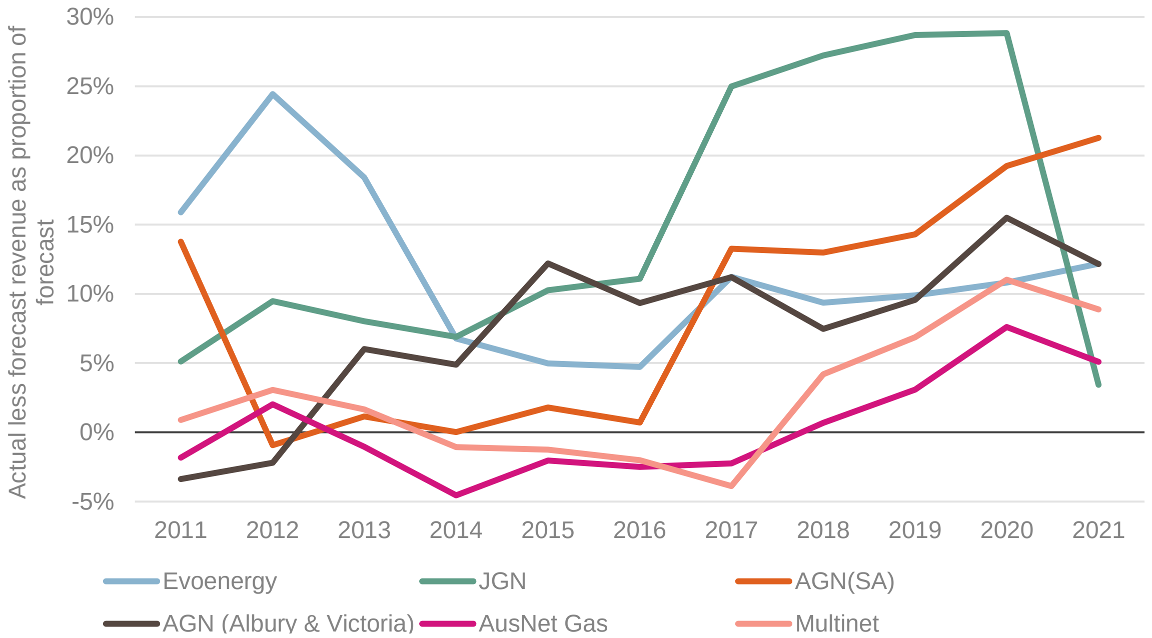
**Figure 4-14 Reference service revenue compared to forecast revenue – RBP, VTS**




Source: Operational performance data - Transmission. Original sources: Annual RINs – F3.1 Reference services (reference services revenue) and PTRMs – Revenue summary – Building block components (forecast revenue). AER calculation to convert into $2021 terms.

Figure 4-15 and Figure 4-16 shows the difference between actual and forecast revenue as a proportion of the forecast for DNSPs and TNSPs respectively. We express these differences as percentages, which are positive when actual revenue exceeded the forecast by that proportion.

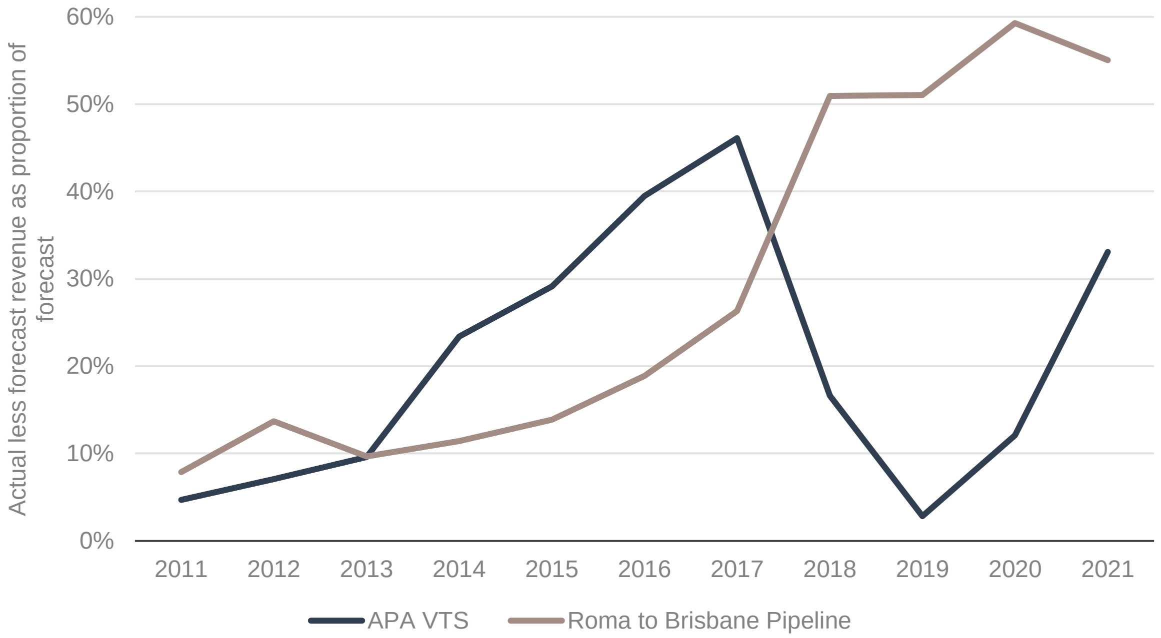
## Figure 4-15 Reference service revenue compared to forecast revenue – DNSPs




Source: Operational performance data - Distribution. Original sources: annual RINs – F3.1 Reference services (reference services revenue) and PTRMs – Revenue summary – Building block components (forecast revenue). AER calculation to convert into $2021 terms and to calculate percentage change (revenue less forecast revenue divided by forecast revenue).

Note: JGN's revenue outperformance from 2015-16 is influenced by several factors discussed below. One major influence was the application of enforceable undertakings pending the outcome of limited merits review appeal process.

## Figure 4-16 Actual revenue compared to forecast revenue – RBP, VTS[23]




Source: Operational performance data - Transmission. Original sources as Figure per 4-15.

23 We report actual revenue, including revenue from reference services. TNSPs 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. For example, APA reports actual reference service revenue as 100% of total revenue for the VTS, but only 23.8% for RBP in 2021.

Together Figure 4-15 and Figure 4-16 show that RBP and VTS have experienced higher percentages of revenue outperformance than any DNSP has over 2011–2021.

In Section 6.2.2, we observe that revenue effects (which is mainly driven by demand outperformance) affected TNSPs more than they affected DNSPs. There are several plausible reasons for this relationship, which would be valuable to explore in future reports. Some of these reasons stem from TNSPs predominantly transporting gas to a small number of large consumers. This feature of TNSPs could make forecasting demand more challenging and creates greater scope for TNSPs to structure tariffs to stimulate demand (including by providing non-reference services). For instance, it is plausible that RBP's higher revenue outperformance later in the measurement period related to its greater use of capacity tariffs.[24]

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 network 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, 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. We consider 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 NSPs re-balancing or varying tariffs within 'side-constraints'. This re-balancing can impact overall revenue recovery relative to forecast. NSPs may choose to re-balance tariffs with a view to increasing demand, which they are incentivised to do under price caps. We would expect increased demand to be reflected in the following period's demand forecasts, thereby lowering prices for future periods. As such, if NSPs recover more revenue than forecast because they are actively responding to incentives to stimulate demand, outperformance will be indicative of lower future prices for reference services.

The example below uses JGN's revenue growth to illustrate how the various factors affecting revenue can interact.

24 RBP changed from having a capacity tariff and throughput tariff from 1 September 2012. See APT Petroleum Pipelines Pty Ltd, *Access arrangement effective 1 September 2012–30 June 2017*, August 2012, p. 13; APT Petroleum Pipelines Pty Ltd, *RBP proposed revised access arrangement effective 1 January 2018 to 30 June 2022*, November 2017, p. 18.

**JGN's revenue growth**

While most gas NSPs typically recover revenue above forecast, Figure 4-15 shows this pattern was particularly pronounced for JGN over 2015 to 2020. JGN's revenue outperformance as a proportion of forecast revenue was as high as 28.8% in 2020, but then declined materially in 2021 to 3.4%.

Several factors influence annual tariff variation adjustments under price caps, which affect revenue recovery for all gas NSPs. A material difference between actual revenue and our PTRM forecast was driven by demand growth. JGN's customer numbers increased by approximately 32% over 2011–2020 following a rapid increase in dwelling completions over 2013–2018.[25]

Besides from demand factors, JGN was also unique in that a limited merits review process affected its price path by resulting in a revenue over recovery of around 25% in 2015–2020, which JGN would return to consumers in the 2020–2025 access arrangement period.[26] The remittal also resulted in JGN's annual adjustments from price changes over 2015–2020 all being applied at once in 2020.[27] This adjustment was not reflected in forecast revenue, further contributing to JGN's recovering higher revenue than forecast.

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 NSPs and tariffs. However, we consider differences in forecast and actual revenue provide a useful overall indicator of the impacts of unexpected changes in demand.

We have previously flagged that given the significance of demand to revenue impacts, we will expand our analysis of actual and forecast demand in future reports. As demand uncertainty is increasing and differences between forecast and actual revenue have been widening, we will consult on whether to include this as a focus area in our next gas network performance report.

## 4.2 Network expenditure

In this section, we report on capex and opex trends. We focus particularly on capex, which has more distinct variation across NSPs.

25 Further details on this growth are included in our previous report, AER, *Gas network performance report*, December 2021, p. 38.

26 A remittal is a process to remake parts of an access arrangement final decision pursuant to a determination made by the Australian Competition Tribunal. Further details, including a graphical representation of what JGN's revenue over recovery would have been under the remittal revenue adjustments is available in AER, *Gas network performance report*, December 2021, p. 40.

27 JGN*, Access arrangement 2015 to 2020, AER final decision revisions – schedule 3*, February 2019, pp. 59-65.

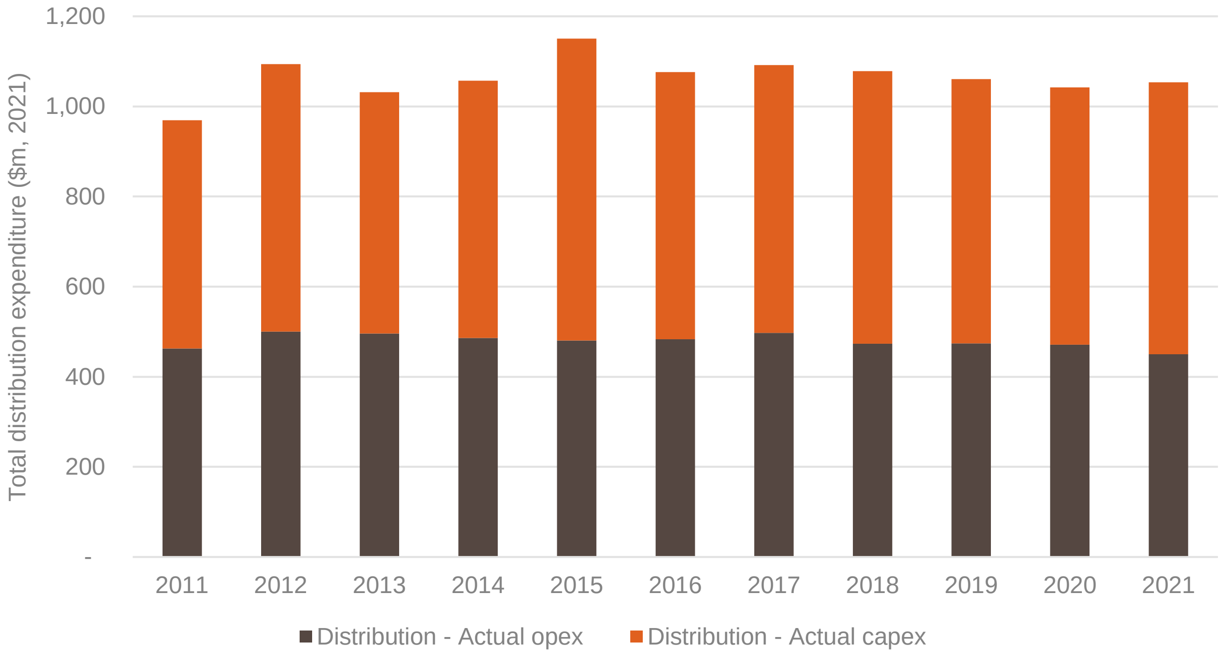
Over 2011 to 2021, we observe that:

- In 2021, total expenditure increased by 1.1% for DNSPs compared to the previous year. Despite this slight increase, total DNSP expenditure is still relatively low, after having declined gradually on average following a capex-driven peak in 2015. However, annual variations have been minor, with total DNSP expenditure remaining around $1.1 billion since 2016.
- In 2021, total expenditure increased by around 15% for TNSPs. Annual expenditure has been increasing for TNSPs since 2018. TNSP expenditure in 2021 was 50.6% higher than the minimum in 2018.
- Opex has remained relatively steady for both DNSPs and TNSPs, with most year-to-year variation driven by capex. Capex is particularly variable for TNSPs.

With the revenue collected from consumers, NSPs undertake opex and capex however they determine to be most efficient in providing a safe and reliable supply of natural gas. Total expenditure presents an overall view that is independent of changes to NSPs' capitalisation policies over time. It also illustrates the potential trade-offs between opex and capex.

Figure 4-17 shows gas DNSPs' total expenditure over 2011 to 2021. This has shown little variation and has been around $1.1 billion each year since 2012. Total expenditure amongst fully regulated gas DNSPs reached a peak of $1.15 billion in 2015 and was $1.05 billion in 2021.

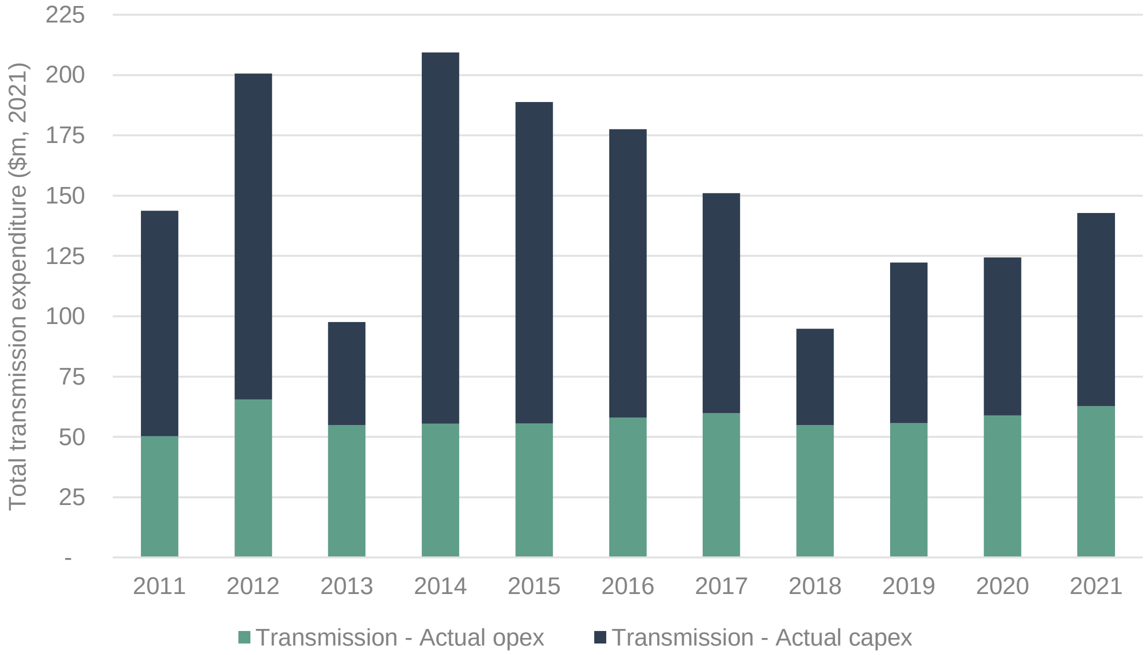
**Figure 4-17 Expenditure – DNSPs**




Source: Operational performance data – Distribution. Original source for opex is annual RINs – F4.1 Opex by purpose. Original source for capex is 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. AER calculations to convert into $2021 and to calculate net capex (gross capex minus capital contributions minus disposals).

Figure 4-18 shows gas TNSPs' total expenditure over 2011 to 2021. While TNSPs' total opex has been steady, their capex has varied considerably. The small size of some TNSPs contributes to these lumpy capex profiles. These lumpy capex profiles drove TNSPs to experience large annual variation in total expenditure relative to DNSPs. Total expenditure amongst fully regulated gas TNSPs reached a peak of $209 million in 2014 before falling consistently to a low of $95 million in 2018, and then increasing annually to reach $143 million in 2021.

**Figure 4-18 Expenditure – TNSPs**




Source: Operational performance data – Transmission. Original source for opex is annual RINs – F4.1 Opex by purpose. Original source for capex is 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. AER calculations to convert into $2021 and to calculate net capex (gross capex minus capital contributions minus disposals).

**Operating and capital expenditure**

Capex and opex affect what revenue NSPs can collect from their customers differently in the short term. In particular:

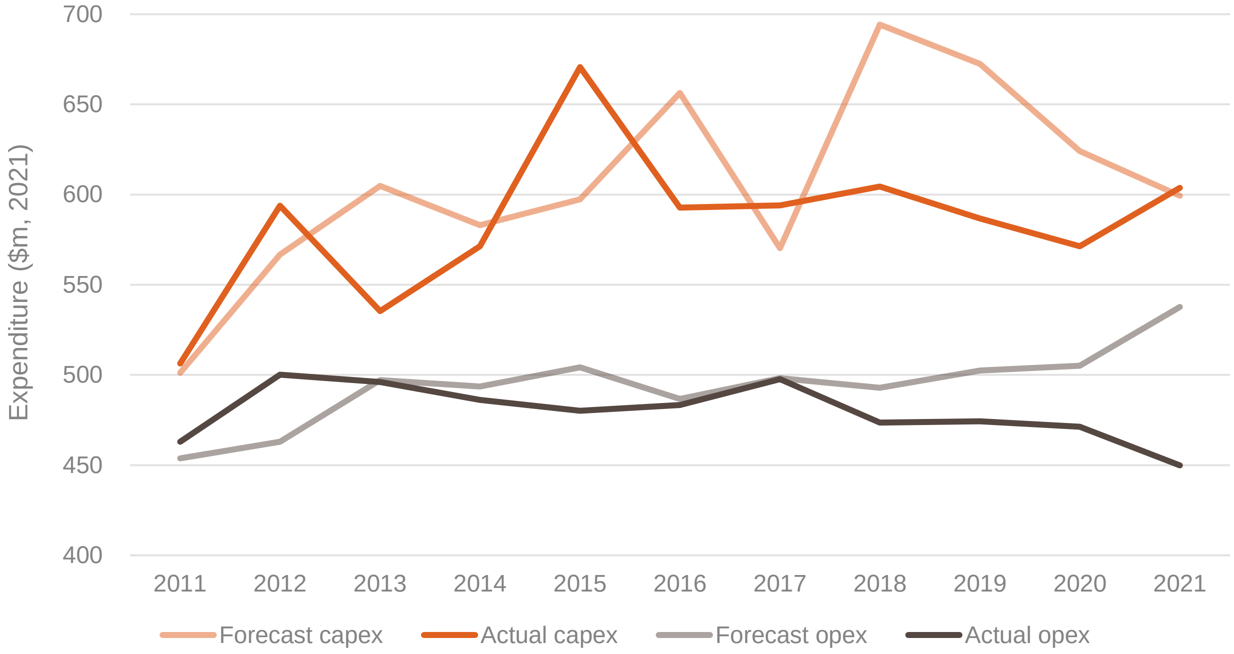
- Forecast opex translates directly into overall revenue allowances in the years we expect the expenditure to occur.
- Capex is added to the capital base. NSPs fund this capex through debt and equity capital raising. They recover the costs associated with this capital raising (return on capital and depreciation) gradually over the economic lives of the assets. Asset lives can range from depreciating within a single regulatory period to upwards of 50 years, depending on the asset category.

Over 2011 to 2021:

- NSPs typically incurred a similar amount of opex to what we forecasted. This relatively consistent outcome likely reflects the recurrent, and therefore predictable, nature of opex:
    - DNSPs on average incurred less opex than forecast most years, including from 2018 onwards.
    - TNSPs on average underspent about as much opex as they overspent relative to what we forecast.
- Capex has been more variable, with a mixture of aggregate overspends and underspends compared to forecast:
    - On average, while DNSPs spent materially less capex than forecast in 2018–2020, actual capex aligned with our forecasts in 2021.
    - On average, gas TNSPs spent materially more capex than forecast most years, with 2018–2020 being the exceptions.

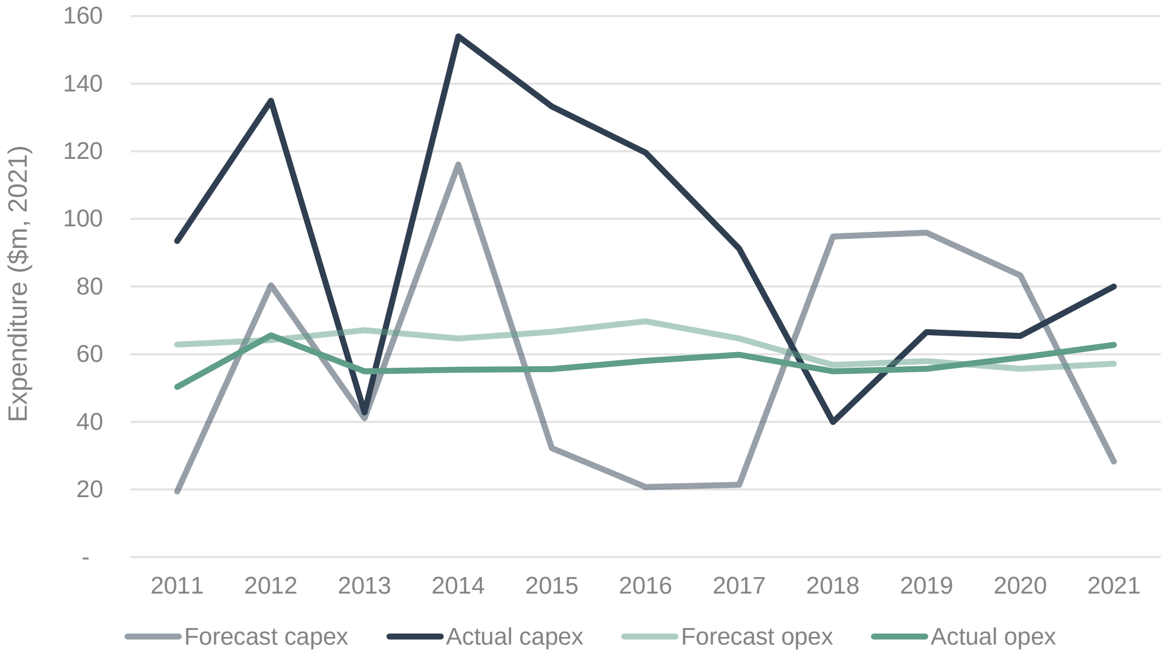
Figure 4-19 and Figure 4-20 compare total opex and capex outcomes against our forecasts for DNSPs and TNSPs, respectively.

**Figure 4-19 Comparison of actual and forecast expenditure – DNSPs**




Source: Operational performance data – Distribution. Original source for opex is annual RINs – F4.1 Opex by purpose. Original source for capex is 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. Original source for forecasts is PTRMs – PTRM Input – Forecast operating and maintenance expenditure and forecast net capital expenditure. AER calculations to convert into $2021 and to calculate net capex (gross capex minus capital contributions minus disposals).

**Figure 4-20 Comparison of actual and forecast expenditure – TNSPs**

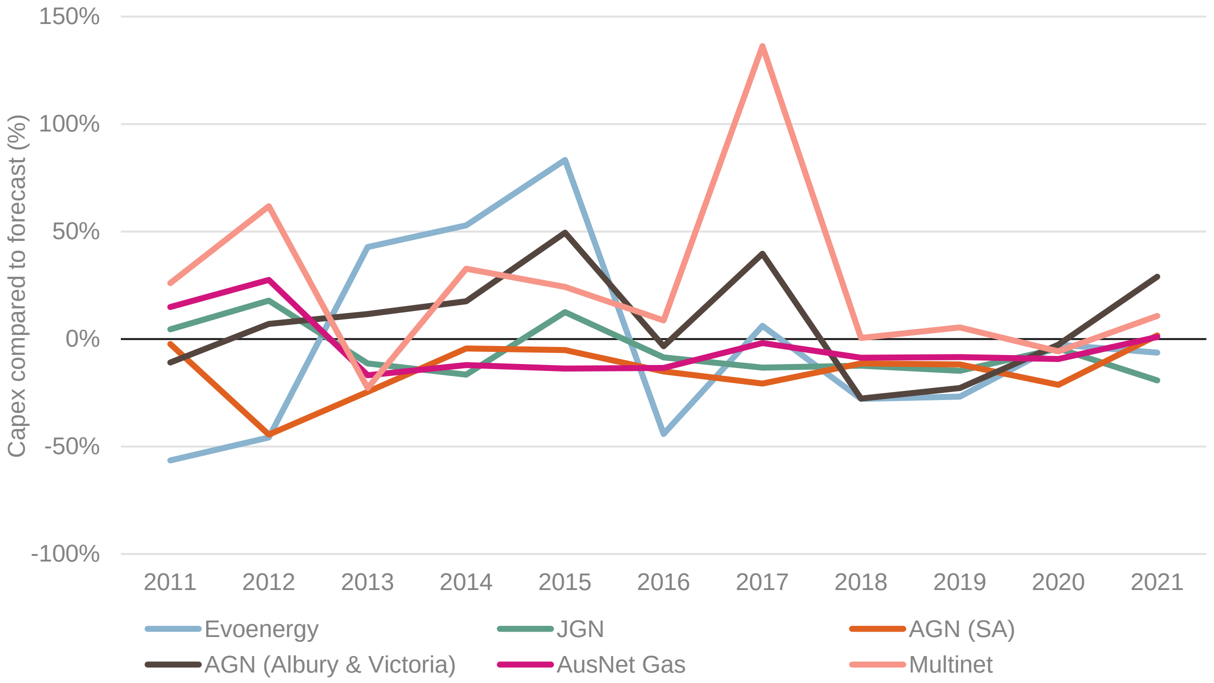



Source: Operational performance data – Transmission. Original source for opex is annual RINs – F4.1 Opex by purpose. Original source for capex is RFMs – RFM input – Actual capital expenditure, Actual asset disposal, Actual capital contributions, or where not available in an RFM, annual RINs – F2.4 Capex by asset class, F2.5 Capital contributions by asset class, F2.6 Disposals by asset class. Original source for forecasts is PTRMs – PTRM Input – Forecast operating and maintenance expenditure and forecast net capital expenditure. AER calculations to convert into $2021 and to calculate net capex (gross capex minus capital contributions minus disposals).

As Figure 4-21 and Figure 4-22 show, when viewed at an individual NSP level, the difference between actual and forecast capex varies materially between NSPs and years. These outcomes likely reflect the lumpiness of capex on long lived assets and how NSPs plan and execute their capex projects in each access arrangement period. These outcomes may also reflect NSPs' expenditure incentives (see 'Expenditure incentive schemes for DNSPs' below).

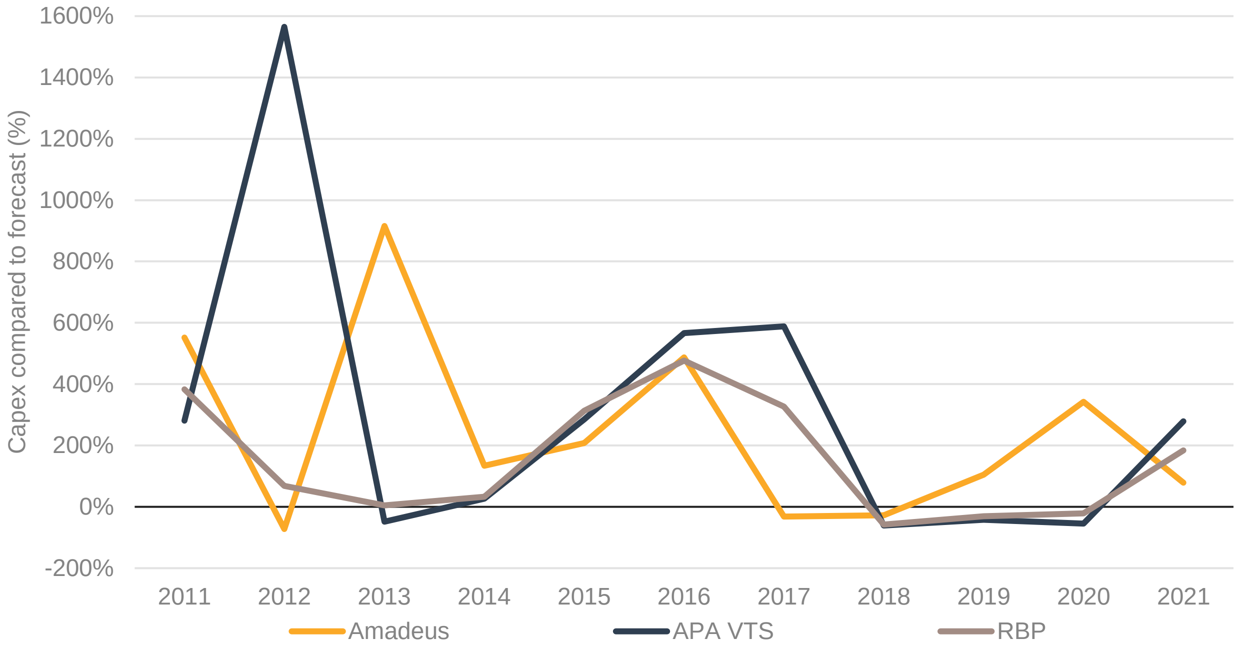
Figure 4-21 and Figure 4-22 also indicate that capex forecasting appears to be improving over time, with differences between actual and forecast capex generally narrowing over the period.

### Figure 4-21 Capital expenditure compared to forecast – DNSPs




Source: Operational performance data – Distribution. Original source for actual capex is 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. Original source for forecast capex is PTRMs – PTRM Input – Forecast net capital expenditure. AER calculations to convert into $2021, calculate net capex (gross capex minus capital contributions minus disposals) and to calculate the comparison as (capex – forecast capex) ÷ forecast capex.

### Figure 4-22 Capital expenditure compared to forecast – TNSPs




Source: Operational performance data – Transmission. Original source as per Figure 4-21.

Figure 4-22 shows that the three gas TNSPs often incur materially more capex than forecast. Previous AER access arrangement decisions indicate that this is predominately driven by TNSPs incurring unexpected expenditure rather than the AER approving materially less than what TNSPs proposed (see ‘Capex amongst TNSPs’ below).

All else being equal, incurring substantially more capex than forecast would have a negative impact on profitability. In practice, this negative effect seems to be mitigated or offset such that TNSPs 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 TNSP earns a depreciation allowance and return on capital.
- As an offsetting factor, lower forecast expenditure would in part reflect the expectation that NSPs would be servicing less demand. Demand for reference services has been higher than forecast, with higher demand creating costs associated with connections, capex and opex. As gas NSPs 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 gas TNSPs.

### 4.2.1 Expenditure incentive schemes for DNSPs

We observe that while DNSPs’ actual opex has consistently been about or slightly lower than forecast on average, their capex has been more variable (Figure 4-19). In large part, this would reflect that opex is recurrent and therefore predictable relative to capex, which is lumpy in nature.

In last year’s report, we suggested these outcomes may also in part reflect the operation of incentive schemes. Specifically, we have applied opex efficiency schemes to gas DNSPs since we assumed responsibility for their regulation in 2010. However, we only started to apply a capex sharing scheme (CESS) to gas DNSPs from 2018.

After consulting with gas DNSPs and stakeholders, we decided to implement a CESS to incentivise gas DNSPs to undertake efficient capex during an access arrangement period.[28] The CESS was applied to the Victorian gas DNSPs from 2018, JGN from 2020, and Evoenergy Gas and AGN (SA) from 2021. We noted in the Victorian 2018 to 2022 access arrangement decisions that the CESS would provide the benefits of efficient capex by:[29]

- Smoothing capex incentives throughout the access arrangement period
- Placing downward pressure on capital asset base growth

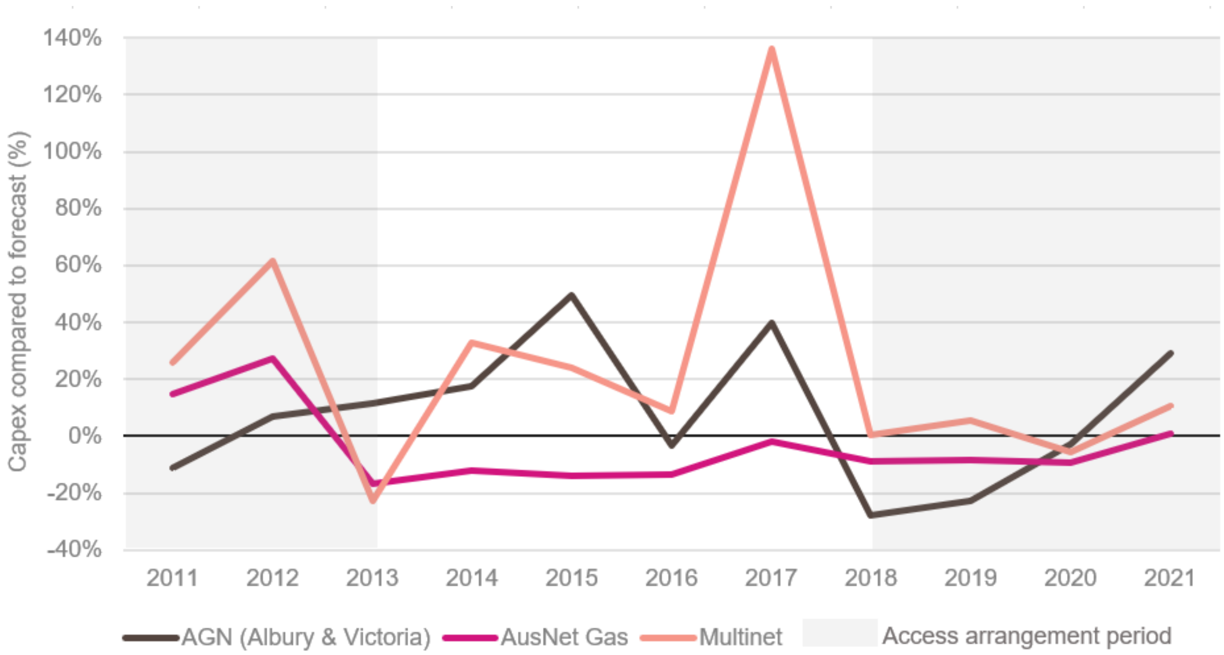
28 We commenced consultation with the information paper: AER, *Capital expenditure sharing scheme for gas distribution network service providers – Information paper*, 2016, p 5.

29 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.

- 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 gas DNSPs, we intend to monitor this impact in future reports. The most data we have currently available is on the Victorian DNSPs as the CESS was first applied in their 2018–2022 access arrangements. Figure 4-23 illustrates that this period has been correlated with capex being similar to or lower than forecast. However, we would need further information to understand if any changes in expenditure reflect the introduction of the CESS to gas DNSPs.

**Figure 4-23 Capital expenditure compared to forecast over access arrangement periods – Victorian DNSPs**




Source: Operational performance data – Distribution. Original source for actual capex is 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. Original source for forecast capex is PTRMs – PTRM Input – Forecast net capital expenditure. AER calculations to convert into $2021, calculate net capex (gross capex minus capital contributions minus disposals) and to calculate the comparison as (capex – forecast capex) ÷ forecast capex.

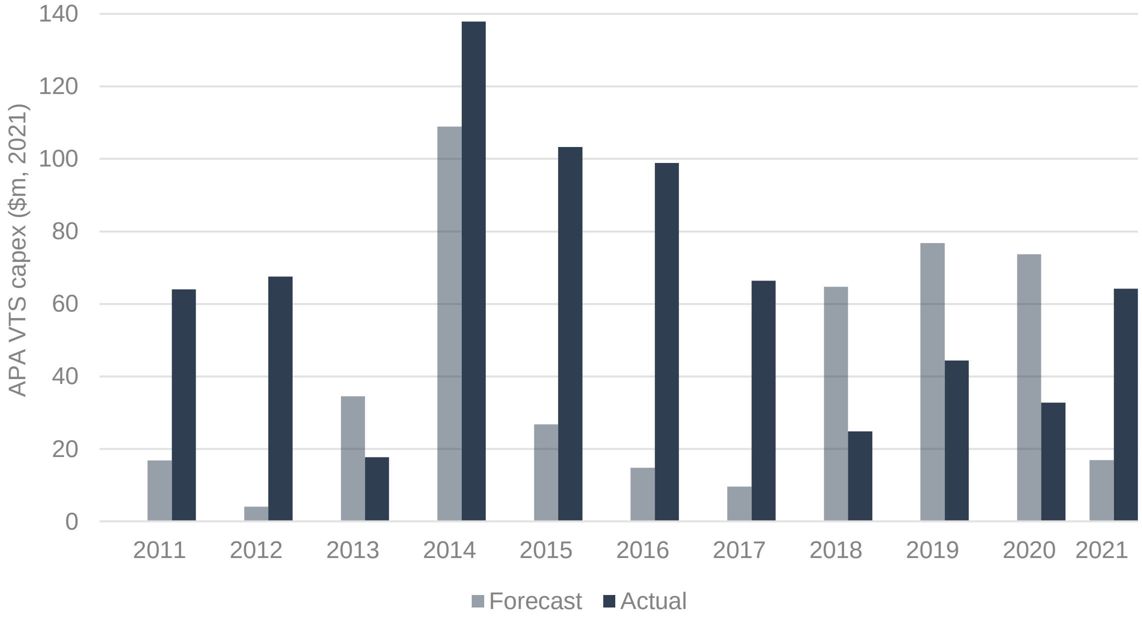
### 4.2.2 Capex amongst TNSPs

In contrast to the fully regulated gas DNSPs, TNSPs operate fewer assets and their capex is less driven by customer connections (a greater proportion is driven by meeting safety and integrity drivers). As such, the profile of actual and forecast capex for each of the three fully regulated gas TNSPs is particularly lumpy and unique to each TNSP. This limits the usefulness of industry-wide observations.

Recognising the uniqueness of each TNSP's capex profile, this section closely examines how forecast and actual capex has varied over time for each TNSP.

Unlike RBP and Amadeus, which rarely report network capacity changes or expenditure on network expansion, VTS regularly increases its capacity and reports augmentation expenditure. In fact, about 83% of VTS's conforming capex for the 2013–2017 access arrangement period was on augmentation.[30]

**Figure 4-24 Capital expenditure compared to forecast –VTS**




Source: Operational performance data – Transmission. Original source for actual capex is 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. Original source for forecast capex is PTRMs – PTRM Input – Forecast net capital expenditure. AER calculations to convert into $2021 and to calculate net capex (gross capex minus capital contributions minus disposals).

As Figure 4-24 shows, VTS incurred materially higher capex than forecast over the 2013 to 2017 access arrangement period. In approving this capex to be rolled into VTS's capital base, we observed several drivers of this difference. However, the main driver was one major project in response to increased demand for the northern flow of gas from Victoria – known as the Victorian Northern Interconnect Expansion.[31]

During the current (2018–2022) access arrangement period, VTS has materially underspent its capex allowance in all years except 2021. This reflects events that appear to be outside of VTS's control resulting in the Anglesea project not going ahead in 2018 and 2019, and expenditure on the Western Outer Ring Main project predominately occurring in 2021 and 2022, rather than 2018 to 2020.[32]

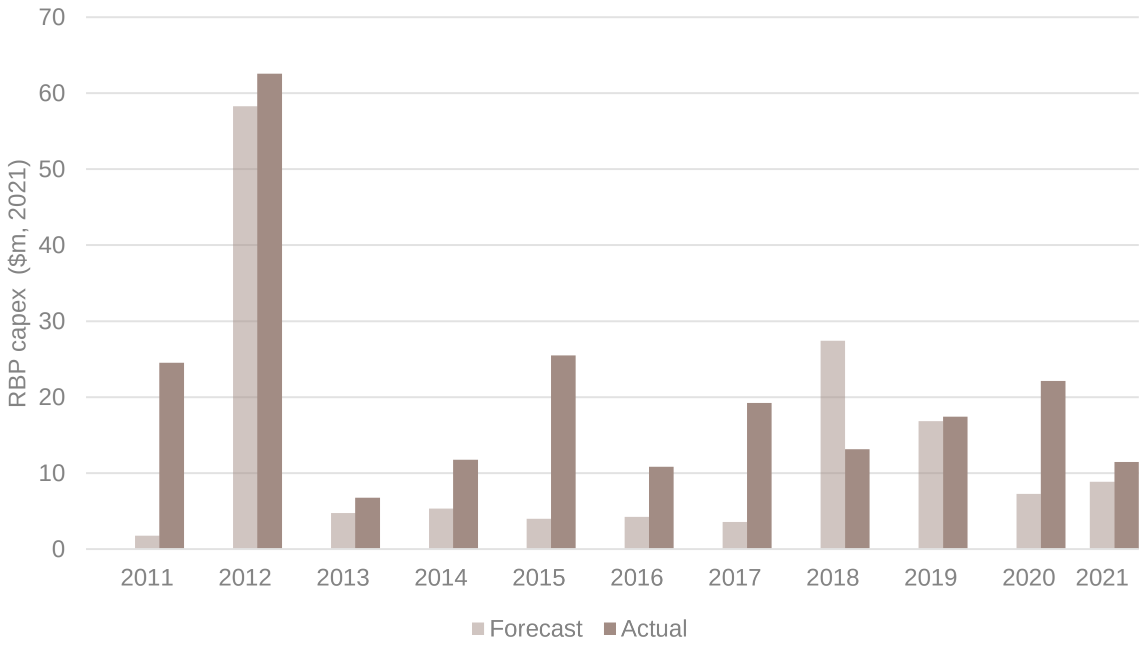
30 AER, *Final decision: APA VTS Australia gas access arrangement 2018 to 2022: Attachment 6*, November 2017, p. 22.

31 AER, *Draft decision: APA VTS Australia gas access arrangement 2018 to 2022: Attachment 6*, July 2017, p. 6-8; APA, *Victorian transmission system access arrangement submission*, 3 January 2017, p. 67.

32 APA, *APA VTS 2023-27 access arrangement reset RIN response – Public*, December 2021, p. 24.

Figure 4-25 shows actual capex compared to forecast for RBP. It shows that RBP spent above its forecast capex every year except for 2018.

**Figure 4-25 Capital expenditure compared to forecast – RBP**




Source: Operational performance data, AER analysis (see Figure 4-24 for original sources and calculations).

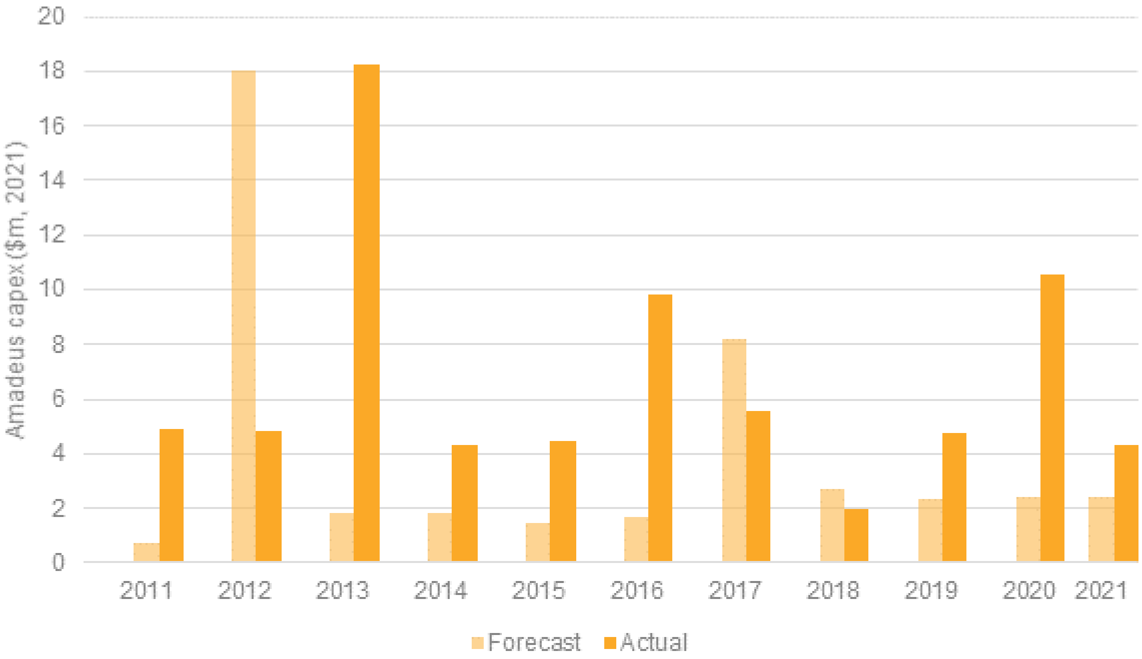
RBP's actual capex ranged from around $7–26 million, except in 2012, where there was a large spike in forecast and actual capex. This investment was followed by a 0.6% increase in RBP's line length, which is the only material change in TNSP line length over observation period. The investment was also followed by a 6.4% increase in capacity.

RBP incurred more capex than forecast every year over the 2012–17 access arrangement period, resulting in it spending 2.4 times what was forecast. We approved most of its capex as conforming to be rolled into the capital base. There were several reasons for the overspend, including that RBP incurred: unexpected capex in response to flood damage, new capex to make RBP bi-directional and replacement capex after having not proposed replacement capex for the access arrangement period.[33]

Amadeus's capex profile, as shown in Figure 4-26 highlights how capex underspends and overspends can swing easily when investments are lumpy, particularly for smaller NSPs. For example, Amadeus's overspend in 2013 mirrors its underspend in 2012, which illustrates how a project deferral can materially influence annual results.

[33] AER, *Draft decision: Roma to Brisbane gas pipeline access arrangement 2017 to 2022, Attachment 6*, July 2017, p. 8–14.

**Figure 4-26 Capital expenditure compared to forecast – Amadeus**




Source: Operational performance data, AER analysis (see Figure 4-24 for original sources and calculations).

Figure 4-26 shows that Amadeus spent more capex than forecast in most years (except 2012, 2017 and 2018).

In deciding to classify Amadeus's actual capex in the 2010–2016 as conforming capex to roll into the capital base, we considered the drivers of any overspends.[34] For example, reasons accepted for capex being higher than forecast included Amadeus accelerating a recoating program to minimise costs that would have been higher if undertaken later.[35] In the 2016–21 period, we approved actual capex as conforming that was 50% higher than forecast. In doing so, we noted that this was due to: Amadeus omitting capitalised overheads from its regulatory proposal, a one-off adjustment in capitalised lease payments to comply with an Australian accounting standard, and an unforeseen project to install pressure control equipment due to interconnection to the Northern Gas Pipeline.[36]

### 4.2.3 Capex amongst DNSPs

While differences in DNSPs' investment programs are less material than for TNSPs, differences between DNSPs can still be substantial. DNSPs still face different operating circumstances and are in different stages of their assets' lives. In contrast to TNSPs, DNSPs report on capex by

34 See for example, AER, *Final decision Amadeus Gas Pipeline access arrangement 2016 to 2021: Attachment 6*, May 2016, p. 6-6; AER, *Final decision: Amadeus Gas Pipeline access arrangement 2021 to 2026*, April 2021, p. 29.

35 AER, *Final decision Amadeus Gas Pipeline access arrangement 2016 to 2021: Attachment 6*, May 2016, p. 6-17

36 AER, *Final decision: Amadeus Gas Pipeline access arrangement 2021 to 2026*, April 2021, p. 29.

purpose as defined in Table 4-1. This data allows us to explore some of the differences between DNSPs more systematically.

### Table 4-1 Capital expenditure purpose and definition

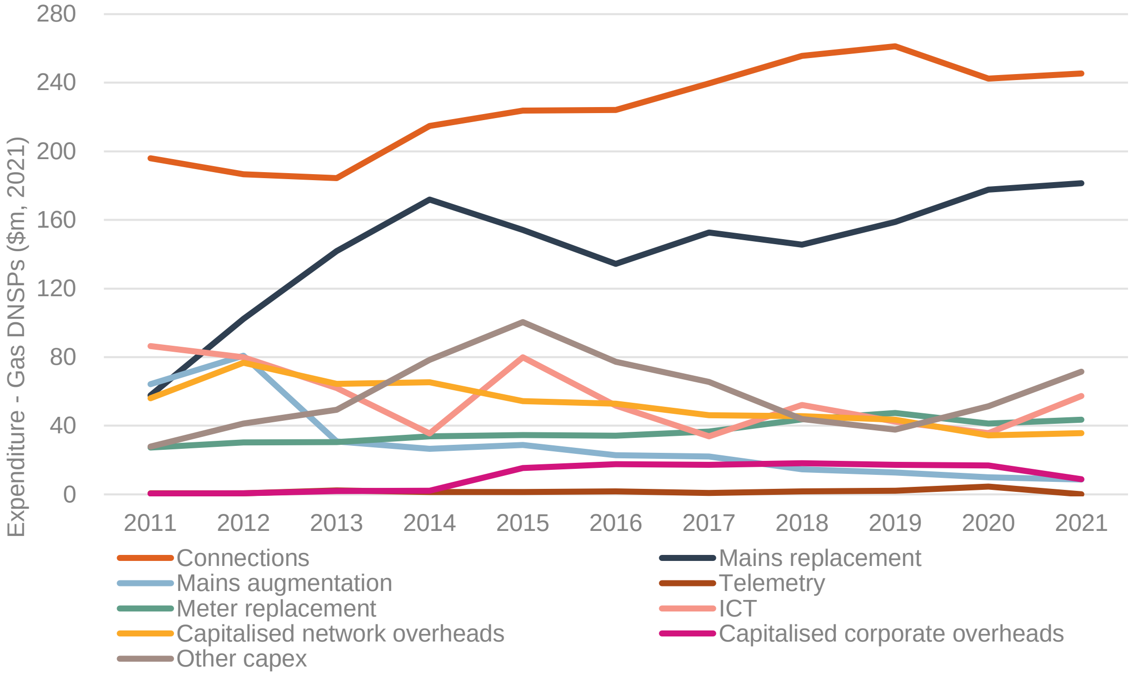
| Capex purpose | Definition |
|---|---|
| Connections | Capex related to connecting new customers to the gas distribution network. |
| Mains replacement | Capex related to replacing the existing mains and services in the gas distribution network due to the condition of those mains and services. This does not include mains and services replaced due to a change in capacity requirements, which is included in mains augmentation. |
| Mains augmentation | Capex related to a change in the capacity requirements of mains and services in the gas distribution network to meet the demands of existing and future customers |
| Telemetry | Capex related to a replacement of SCADA operating in the network 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 expenditure 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. This is associated with but not restricted to vehicles and non-operational buildings. |

Over 2011 to 2021, we observe that connections expenditure, driven by customer demand and mains replacement expenditure were a large proportion of the investments that gas DNSPs made. Expenditure on both these items increased marginally in 2021 relative to 2020.

Figure 4-27 sets out capex by purpose combined across all the gas DNSPs. This shows that the capex categories of connections and mains replacement are the main capex drivers, adding new long-lived assets to the capital base. Growth in distribution customer numbers drove much of the capex on connections and meeting safety and reliability requirements drove much of the replacement capex.[37] While mains replacement capex has been high, mains augmentation capex has decreased over the period, illustrating the most gas capex goes to safely maintaining the existing network.

[37] ESCV, *Review of Gas access arrangements final decision,* 2002, p. 117.

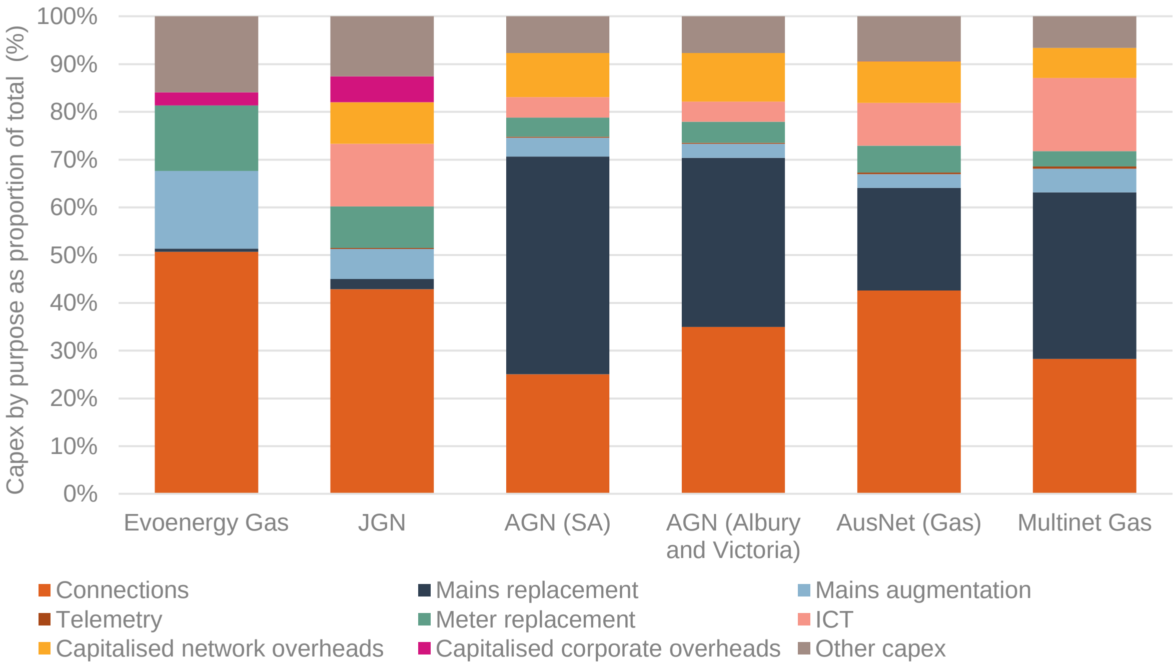
## Figure 4-27 Capital expenditure by purpose – DNSPs




Source: Annual RINs – E1.1.1 Reference Services. AER calculation into $2021 terms.

Figure 4-28 demonstrates the notable variation across DNSPs in the average proportion of actual capex incurred for each of the categories over 2011 to 2021.

## Figure 4-28 Capital expenditure by purpose as proportion of total (2011–2021) – DNSPs




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 DNSP's total capex.

Figure 4-28 shows that a large proportion of capex is on mains replacement in Victoria and SA. This reflects that the Victorian and SA DNSPs have undertaken or have been undertaking substantial mains replacement programs over the 2011–2021 period.

**Mains replacement programs**

Mains replacement programs commenced for the Victorian gas DNSPs in their 2003–2007 access arrangement period and aimed to progressively replace the ageing cast iron pipelines to meet safety and reliability requirements.[38] 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 DNSPs,[39] 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%,[40] and we have no reports of Evoenergy Gas having had any cast iron mains.

Low pressure replacement programs for the other DNSPs are still ongoing. This was noted by AGN (SA) in its recent access arrangement proposal for its 2022–2026 access arrangement period.[41] In Victoria, AGN (Albury and Victoria) expected to complete their program in the 2018–2022 access arrangement period,[42] AusNet Gas stated their program would continue until 2025 and Multinet Gas indicated their 30 year program was expected to conclude in 2033.[43] These programs have influenced the capex allowances forecast for these gas DNSPs in their current access arrangements.

## 4.3 Capital bases

The NSPs' capital bases capture the total economic value of assets that are providing reference services to customers. These assets have accumulated over time and will be at various stages of their economic lives. An individual NSP's assets may be relatively old or new, depending on the NSP's network growth and where it is in the replacement cycle.

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

38 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.

39 ESCV, *Review of unaccounted for gas benchmarks: final decision – calculation*, 2017, p. 5.

40 JGN, *JGN – 2021 to 2026 access arrangement revised proposal – Attachment 8.5*, 2019, p. i.

41 AGN (SA), *Five year plan for our SA network – July 2021 to June 2026*, 2020 p. 3.

42 AGN (Albury & Victoria), *Final plan: Access arrangement information 2018-2022*, December 2016, p. 83.

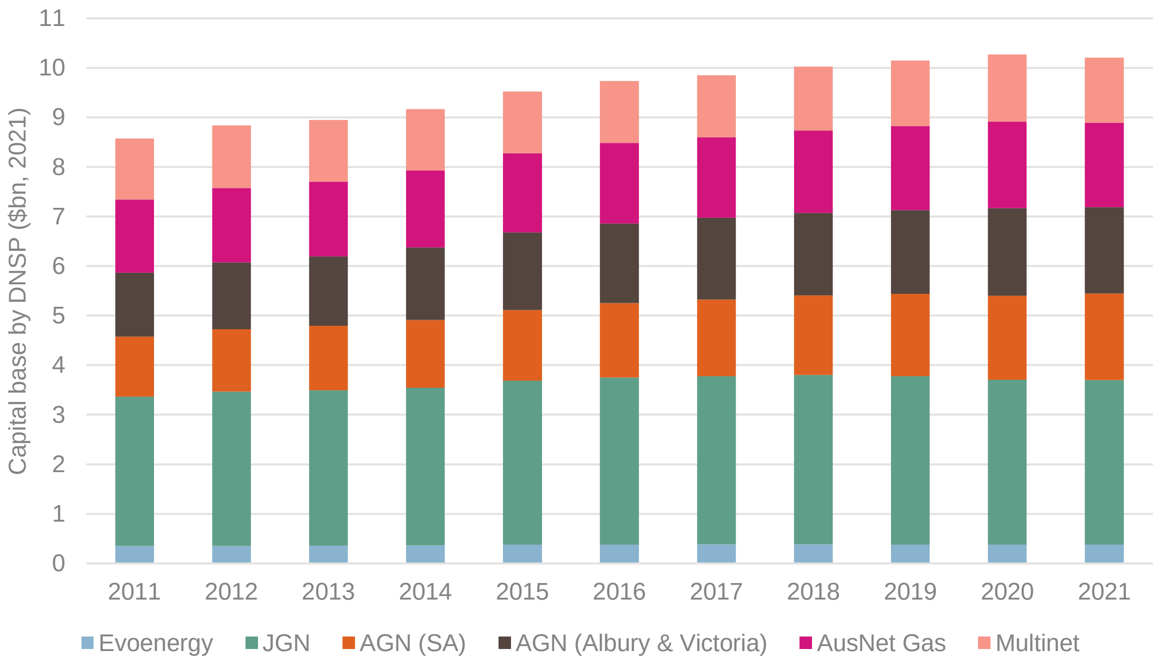
43 AusNet Gas, *Gas access arrangement review: 2018-2022: Access arrangement information*, December 2016, p. 106; Multinet Gas, *2018 to 2022 access arrangement information*, 2016, p. 56.

Over 2011 to 2021, we observe that:

- The total value of regulated network assets has grown by approximately 20% (19% for distribution and 28% for transmission).
- Capital bases have grown across all jurisdictions but have done so to the greatest extent in Victoria and SA.
- Capital base growth compared against customer numbers and volumes of gas delivered emphasises that the capital intensiveness of most gas DNSPs 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 that this margin is widening with its mains replacement program.
- Capital bases decreased slightly for DNSPs (0.67%) and TNSPs (0.09%) over 2021.

Figure 4-29 and Figure 4-30 set out the combined capital bases of the six DNSPs and three TNSPs, respectively. DNSPs' combined capital bases have increased gradually since 2011, before reducing in 2021.

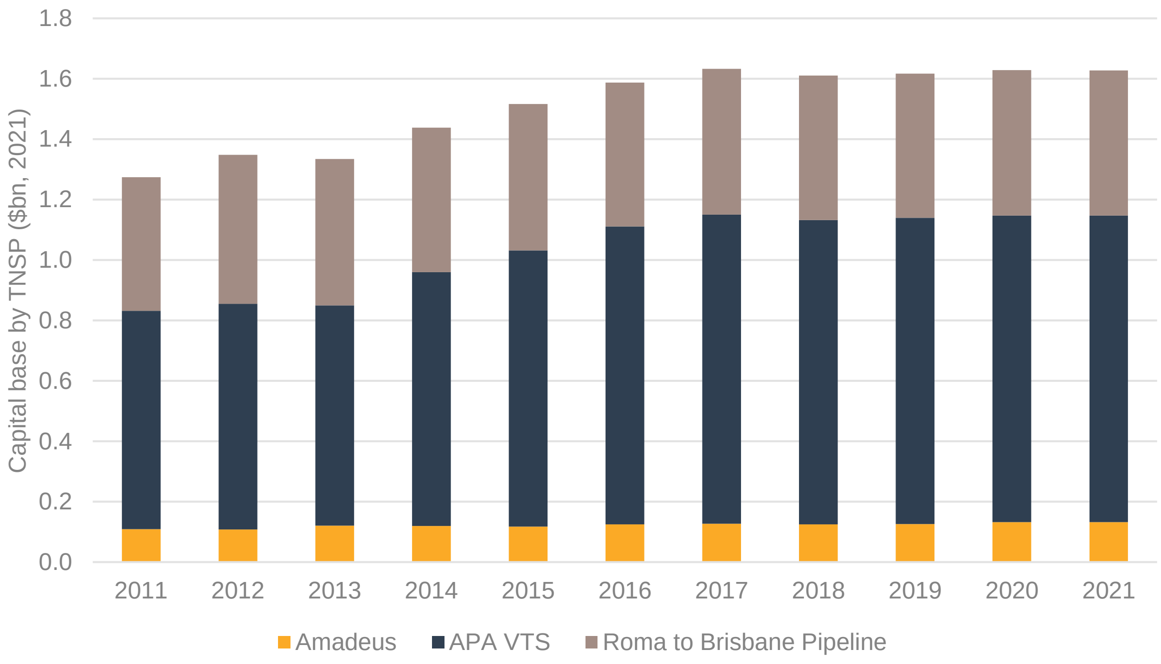
**Figure 4-29 Capital base by DNSP**




Source: Operational performance data – Distribution. Original source: RFMs – Total capital base roll forward – Interim closing capital base, or where unavailable in an RFM, annual RINs – F10.1 Capital base values. AER calculation to convert into $2021 terms.

Figure 4-30 shows that TNSPs' capital bases grew more rapidly than DNSPs over 2011 to 2017, but then lowered and flattened.

**Figure 4-30 Capital base by TNSP**



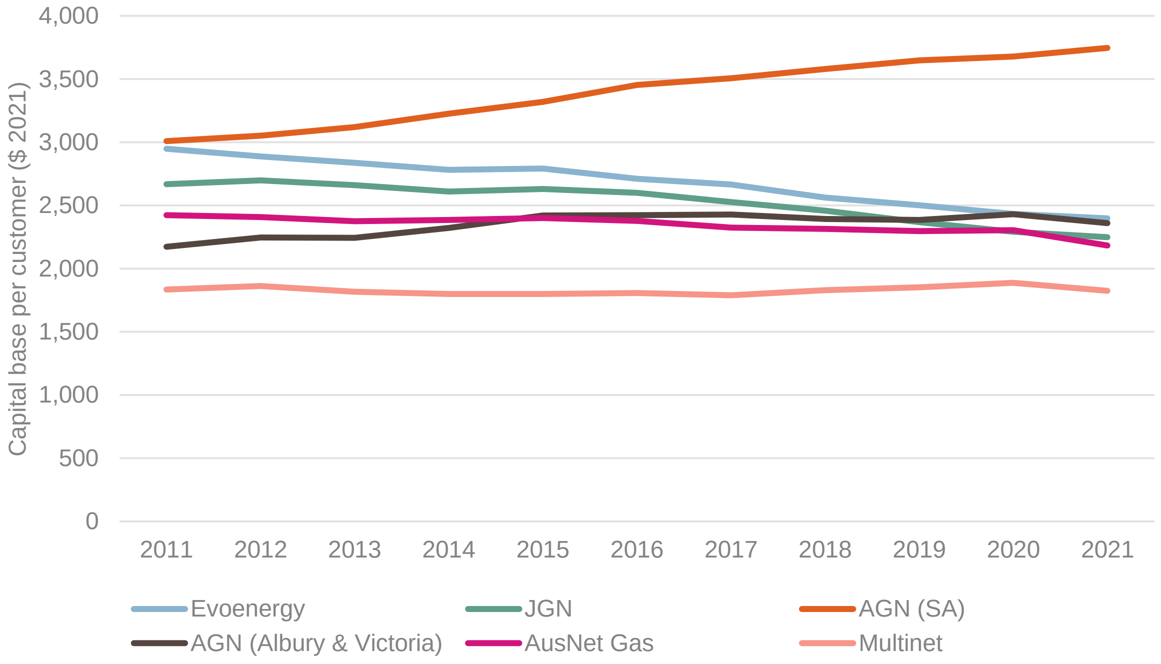

Source: Operational performance data – Transmission. Original source: RFMs – Total capital base roll forward – Interim closing capital base, or where unavailable in an RFM, annual RINs – F10.1 Capital base values. AER calculation to convert into $2021 terms.

It is important to note that 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 Figure 4-10.

Reflecting the growth in customers connected to gas distribution networks, we generally observe steady to declining capital base per customer amongst DNSPs. An exception to this trend is AGN (SA)'s increasing capital base per customer due to its large mains replacement program, as forecast and included in its 2010–2016 and 2016–2021 access arrangements.[44]

44 AER, *Final decision: AGN access arrangement 2016 to 2021, Attachment 6—Capital expenditure*, May 2016, pp. 7-8.

## Figure 4-31 Capital base per customer – DNSPs

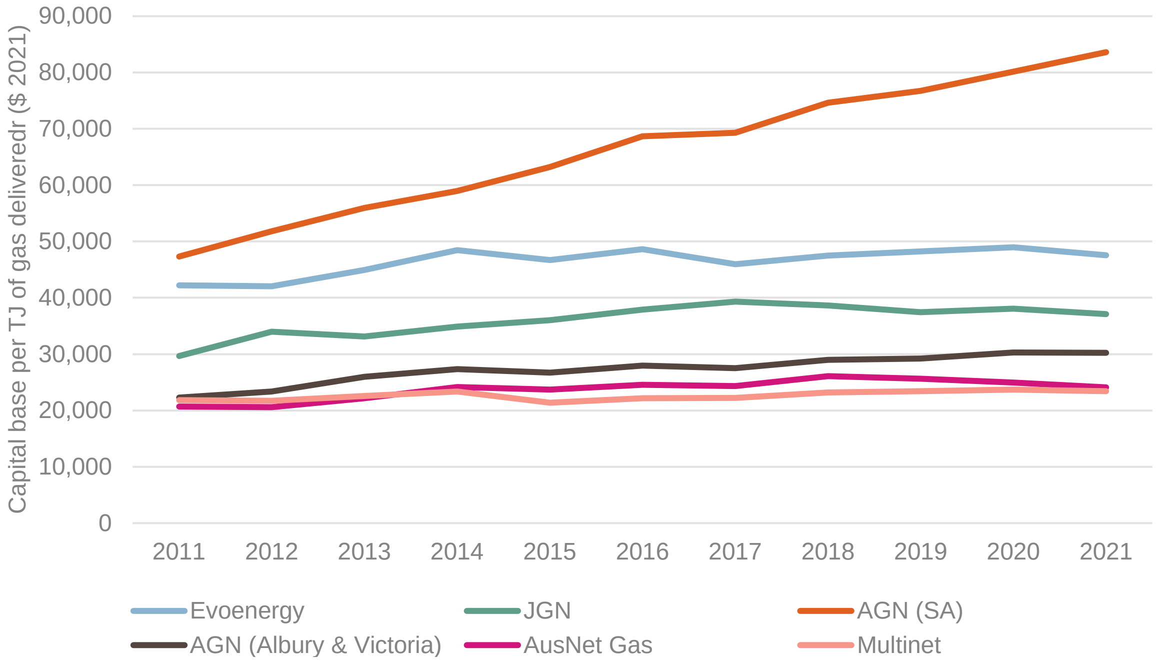



Source: Operational performance data – Distribution. Original source for capital base: RFMs – Total capital base roll forward – Interim closing capital base, or where unavailable in an RFM, annual RINs – F10.1 Capital base values. Customer numbers from annual RINs – S1.1 Customer numbers by customer type. AER calculation to convert into $2021 terms and to divide the capital base for each DNSP by that DNSP's customer numbers.

While capital base per customer is a useful indicator of the average value of capital employed per customer, it is sensitive to the composition of the NSP's customer base. For example, a distribution network such as AGN (SA) with a higher proportion of gas delivered to its industrial customer base might, holding other things constant, be expected to have more capital invested per customer. This metric is also less insightful and more difficult to interpret for TNSPs.

For this reason, we have set out in Figure 4-32 and Figure 4-33 the capital base per volume of gas delivered for DNSPs and TNSPs, respectively. This measure is less sensitive to the composition of customers since it accounts for the different patterns of usage by different customer types.

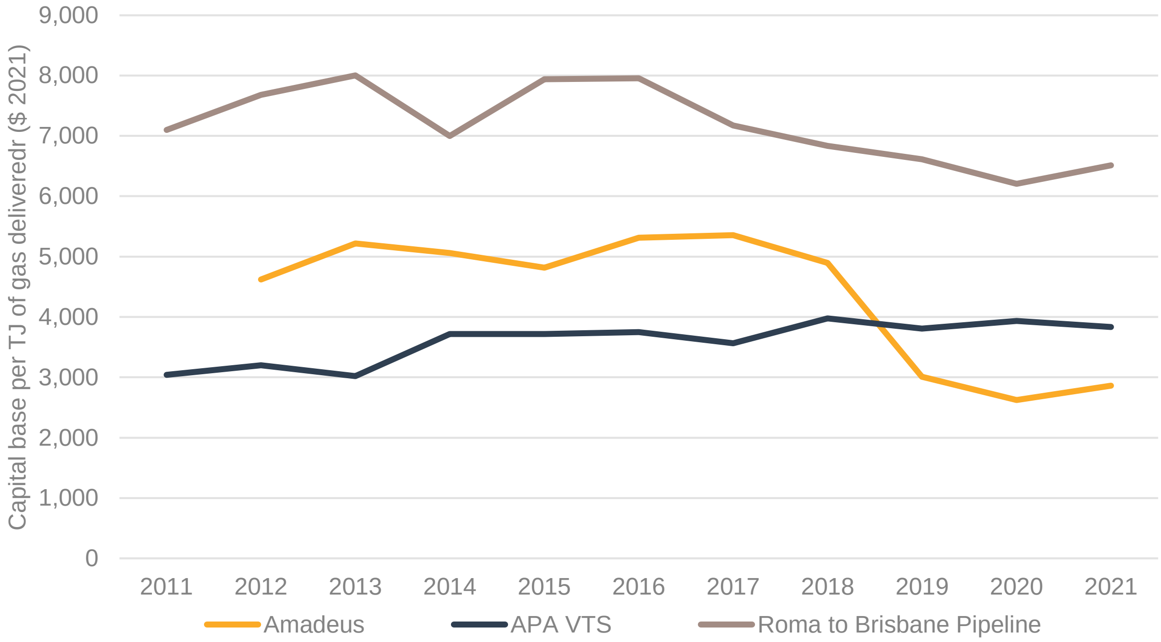
## Figure 4-32 Capital base per TJ of gas delivered – DNSPs




Source: Operational performance data – Distribution. Original source for 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. AER calculation to convert into $2021 terms and to divide the capital base for each DNSP by their gas delivered.

In Figure 4-32 we observe gradual increases in capital base per volume of gas delivered for DNSPs, except for in SA where capital base growth is more rapid.

## Figure 4-33 Capital base per TJ of gas delivered – TNSPs




Source: Operational performance data – Transmission. Original source for 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. AER calculation to convert into $2021 terms and to divide the capital base for each TNSP by their gas delivered.

In Figure 4-33, we see VTS's capital base per volume of gas delivered followed a similar trend to the Victorian gas DNSPs. However, this metric reduced since the start of the measurement period for Amadeus and RBP. The Amadeus pipeline experienced significant growth in gas deliveries from 2019 due to gas being delivered 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.[45] Similarly, gas delivered by RBP is more variable than the value of its capital base, driving variation in the measure over the period.

When normalising using customers or volumes of gas delivered, these measures are likely to be indicative of the underlying asset age profile driving trends in replacement, and/or relative changes in customer numbers and gas demand. For example, despite increases in the number of customers, the aggregate level of gas delivered by DNSPs has declined since 2011. In addition, AGN (SA)'s average annual proportion of mains replacement capex of total capex was 46% from 2011–2021. In comparison, the average annual proportion of mains replacement across all DNSPs was 23% over the same period.

## 4.4 Network service outcomes for customers

This section reports on some of the service outcomes that distribution customers receive from gas DNSPs – network outages and UAFG. While there are other measures of service quality, these two measures are readily quantifiable and reported annually for distribution.

Gas DNSPs are inherently reliable, for reasons discussed further in this section. Over time, we will investigate whether we should expand our reporting to cover service outcomes for TNSPs or include other service outcomes for DNSPs that are important to their customers.

Over 2011 to 2021, we observe that:

- UAFG levels reduced 11.5% over 2021.
- Total UAFG remained relatively stable overall, with some annual variation.
- While UAFG remained fairly stable for most DNSPs, there were some exceptions, including material declines in UAFG on AGN (SA)'s network.
- In 2021, total distribution network outages were at their lowest level since 2011, driven by a trend of lower planned outages. Planned outages have reduced by 35% in 2021 since their peak in 2015.

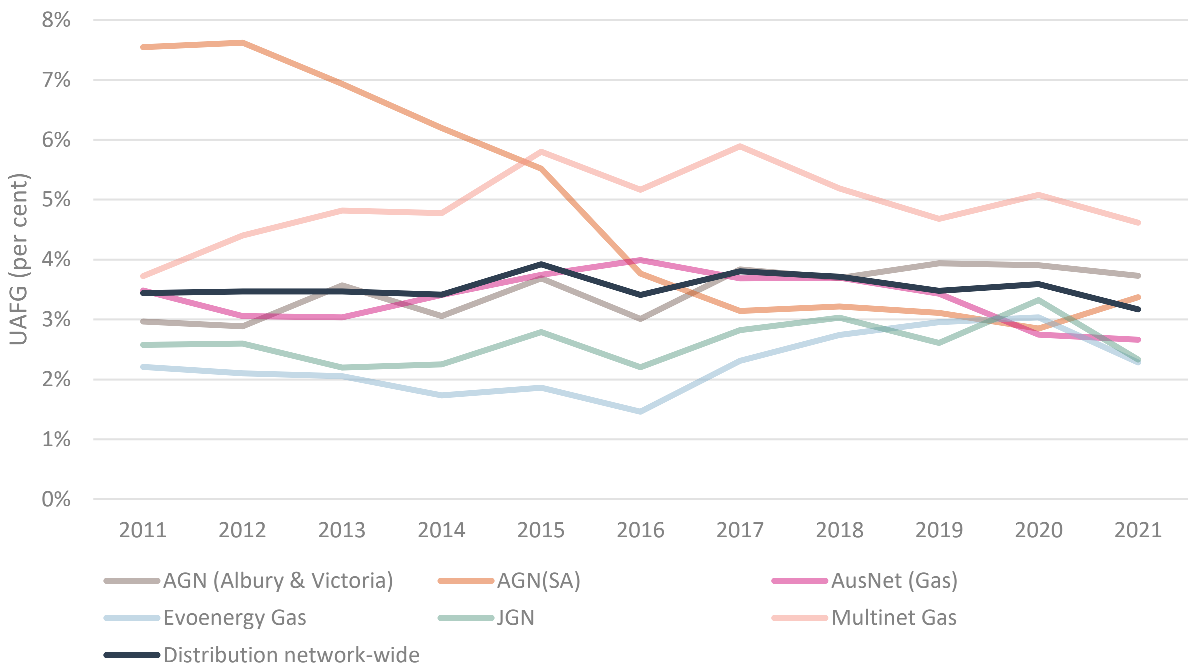
45 APA, *Annual RIN - Amadeus Gas Pipeline: RIN response and basis of preparation*, November 2021, p. 42.

### 4.4.1 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 result from gas leakage, inaccuracies in gas measurement, gas heating values or theft. It is an important measurement for customers as they ultimately face its cost.

UAFG has remained stable on average, for the most part varying from just below 3.5% to 4% of delivered gas volumes. At the individual DNSP level, we observe clearer evidence of trends. Figure 4-34 illustrates the changes from 2011 to 2021 in reported volumes of UAFG as a proportion of total gas delivered for each DNSP.

**Figure 4-34 UAFG as a proportion of gas delivered – DNSPs**




Source: UAFG: Annual RINs – S11.3 UAFG – Transmission and Distribution; Gas delivered: Annual RINs – N1.1 Demand by customer type. AER calculation of UAFG as a percentage of gas delivered for each DNSP. Distribution network-wide values calculated as network-wide UAFG divided by network-wide gas delivered.

Figure 4-34 shows that:

- Levels of UAFG have increased for all but two gas DNSPs over 2011 to 2021.
- AGN (SA) has experienced large reductions in UAFG. While the drivers of UAFG are too complex to attribute precisely, we expect this is partly an outcome of its ongoing mains replacement program, identified in section 4.2.
- As at 2021, there is a narrower range of UAFG levels between gas DNSPs than at the start of the measurement period.

**How UAFG costs impact the cost of reference services**

DNSPs in the ACT, NSW and SA are required to directly contract UAFG volumes. UAFG is therefore included in their allowed opex under our access arrangement decisions and recovered via network charges. DNSPs 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, a DNSP will over (under) recover its actual UAFG costs. This will flow through to customers via a lower (higher) opex forecast in the next access arrangement decision.

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

Under both frameworks, DNSPs are only rewarded or penalised for changes in the relative UAFG volumes, or the benchmark rate. DNSPs are not rewarded or penalised for changes in the absolute levels of UAFG or changes in gas prices. For DNSPs that directly contract UAFG, any volatility from the price of purchasing gas differing from approved forecasts, or the total demand differing from forecasts they are trued-up through the tariff variation mechanism.

## Causes of UAFG

Through our reporting, we intend to explore evidence on the causes of UAFG. UAFG is an important driver of costs for DNSPs, both in terms of the fuel cost and through increasing the need for capex in mains replacement programs. Further, exploring this evidence allows us to test new datasets reported through Annual RINs, and further interrogate and analyse this data when we collect a longer time series.

In its 2017 UAFG benchmarks review, the ESCV observed the following about UAFG drivers:[46]

- Information from the gas DNSPs suggested there are five key UAFG drivers:
    - Fugitive emissions—gas lost into the atmosphere due to leakage from the gas distribution networks
    - Metering errors

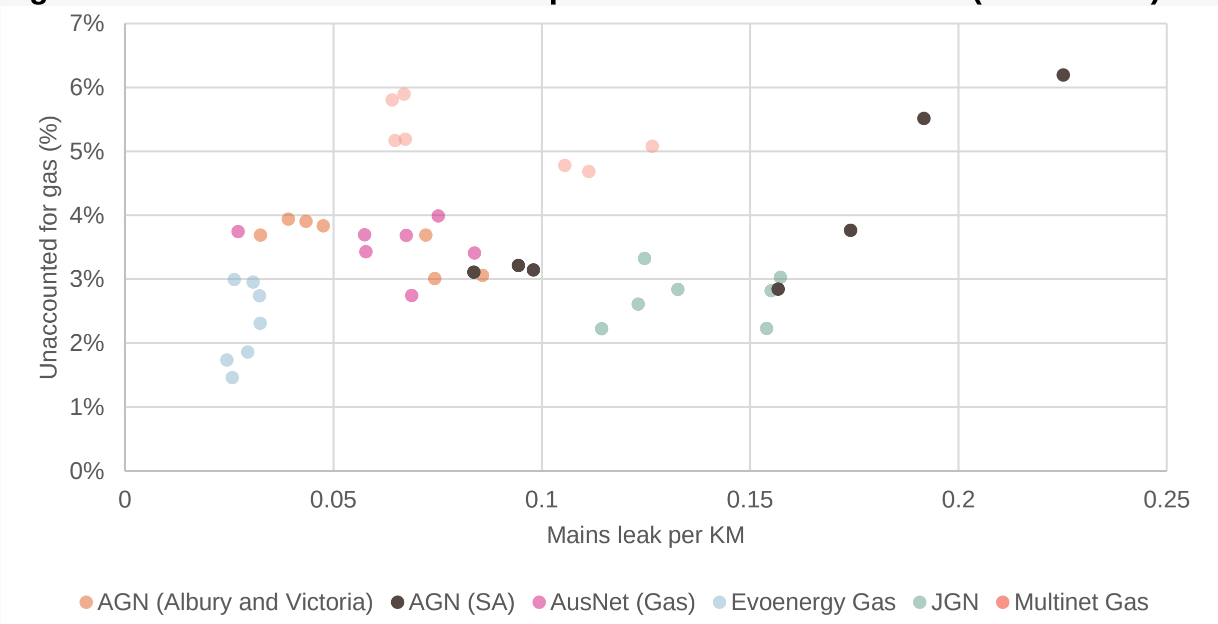
[46] Essential Services Commission, *Review of unaccounted for gas benchmarks: final decision – methodology*, July 2017, pp. 5-9.

- Heating value—the relationship between the volume of UAFG and the quantity of energy lost to customers. This is related to the quality of gas injected into the gas distribution network.
    - Data quality
    - Theft
- The extent to which different factors affect UAFG is uncertain.
- Gas DNSPs have different degrees of control over these causes. For example, DNSPs have relatively high control over fugitive emissions, but heating value depends on the quality of gas injected into the distribution network, which is largely outside their control.

### Testing the relationship between UAFG and mains leaks

Our 2021 Gas network performance report (pp. 57–59) examined the relationship between reported mains leaks and UAFG levels. To test for this relationship amongst DNSPs, we plotted UAFG against reported mains leaks per kilometre between 2014– 2020 (below).

**Figure 4-35 UAFG and mains leaks per kilometre – Gas DNSPs (2014– 2020)**




Source: UAFG from Annual RINs – S11.3 UAFG – Transmission and Distribution. Gas delivered from Annual RINs – N1.1 Demand by customer type. Mains leaks from Annual RINs – S14.1 Loss of containment. Network length from Annual RINs – N2.1 Network length by pressure and asset type. AER calculation of UAFG as a percentage of total gas delivered for each DNSP and of mains leaks per KM of network length for each DNSP.

When pooled across DNSPs, we did not observe a systematic relationship between mains leaks and UAFG. We also observed that outcomes for many of the individual DNSPs were clustered, suggesting some level of random annual variation. However, we also observed some evidence that a relationship may exist in specific circumstances. For instance, AGN (SA) appeared to have a more positive relationship over the period, which coincided with when it commenced a large mains replacement program.

While we have not undertaken further analysis of the causes of UAFG in this report, we will look to deepen our analysis of these relationships in future gas network performance reports.

### 4.4.2 Network outages

Gas NSPs 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.
- Gas NSPs can carry out works without causing supply outages to customers.

Due to these factors, customers experience network outages infrequently. For example:

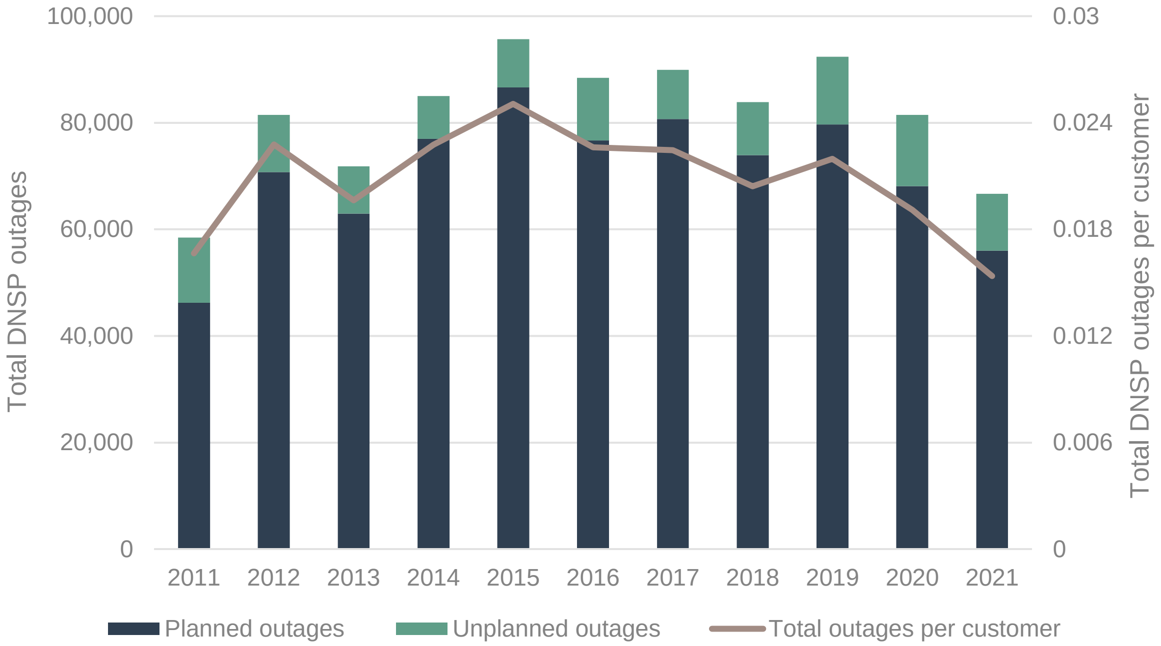
- in 2021 there were on average 0.015 outages per customer.[47] This is equivalent to a customer experiencing an outage approximately once every 66 years on average.
- alongside the infrequent nature of network outages, they also impact relatively few customers at once.

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 4-36 sets out total outages across the gas DNSPs, divided into planned and unplanned outages.

47 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 4-36 Network outages – Total and per customer – DNSPs**




Source: Operational performance data. Original source for Planned and Unplanned Outages: Annual RINs – S11.1 Network outages.

Figure 4-36 shows that:

- In 2021, network outages in total were at their lowest level since 2011.
- This has been driven by a downwards trend in planned outages. Planned outages have reduced by 35% in 2021 from a peak in 2015.
- Conversely, unplanned outages have increased by 33% in 2021 from a low in 2014. Directionally, this is not what we would expect with many gas DNSPs 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 gas DNSPs have adopted materially different approaches to reporting outages. As such, our view is that while Figure 4-36 and the underlying outage data is useful to monitor trends through time, it is less informative about the comparative reliability of individual DNSPs.

# 5 Summary of financial performance in 2021

This section looks at financial performance, or network profitability, as a core performance outcome. This involves considering indicators of profit that NSPs have generated.

The regulatory framework is designed to provide NSPs with a reasonable opportunity to recover at least efficient costs incurred in providing reference services and complying with regulatory requirements.[48] This results in compensating NSPs in expectation for efficiently incurred costs such as opex, depreciation, interest on debt and tax. It also results in providing NSPs with an expected profit margin in line with the required return in the market for an investment of similar risk. If set at an appropriate level and supported by incentives, the expected profit margin should attract efficient investment.

As a feature of the incentive-based regulatory framework, we expect NSPs' actual outcomes to differ from the forecasts and benchmarks we set. The revenue requirement is not a guaranteed return, as NSPs' actual returns reflect whether they spend more or less than the forecasts and benchmarks used to determine their revenue allowances. In fact, incentive-based regulation is designed to encourage NSPs to outperform regulated allowances, which then informs future allowances. For example, an NSP might benefit from cost efficiencies, which would then benefit consumers by informing lower allowances in the future. Similarly, an NSP might benefit from achieving higher demand than forecast, which would inform higher demand forecasts (and therefore lower prices) in the future.

Notwithstanding that we do expect differences between allowed and actual returns, profitability results that are systemically and materially higher or lower than what we forecast a benchmark efficient entity would achieve would prompt us to investigate the causes in greater detail.

As such, reporting on profitability measures should make gas NSPs' returns and their drivers transparent. This reporting should also provide information to assist stakeholders in reviewing the overall effectiveness of the regulatory framework.

This section reports on the following profitability measures:

- Return on assets
- Earnings before interest and tax (EBIT) per customer
- RAB multiples

Given this is the first year we are reporting the return on regulated equity for gas NSPs, we discuss this profitability measure in detail as a focus area in Chapter 6.

All analysis in this section is presented:

- As real returns, excluding annual returns from capital base indexation

48 National Gas Law, Clause 24(2) provides for this as part of the revenue and pricing principles.

- Including rewards and penalties arising from incentive schemes
- Over 2014 to 2021, for consistency with our electricity profitability analysis.

Other permutations of these measures are available in our financial performance dataset, released alongside this report.

## 5.1 Return on assets

The return on assets is a simple, partial profitability measure allowing us to compare network profits against our allowed rates of return. It does not capture all potential drivers of network profits, such as performance against our allowances for the costs of debt (interest expense) or tax expense. However, it does capture the impact of incentive scheme rewards and penalties, as well as performance against our expenditure forecasts.

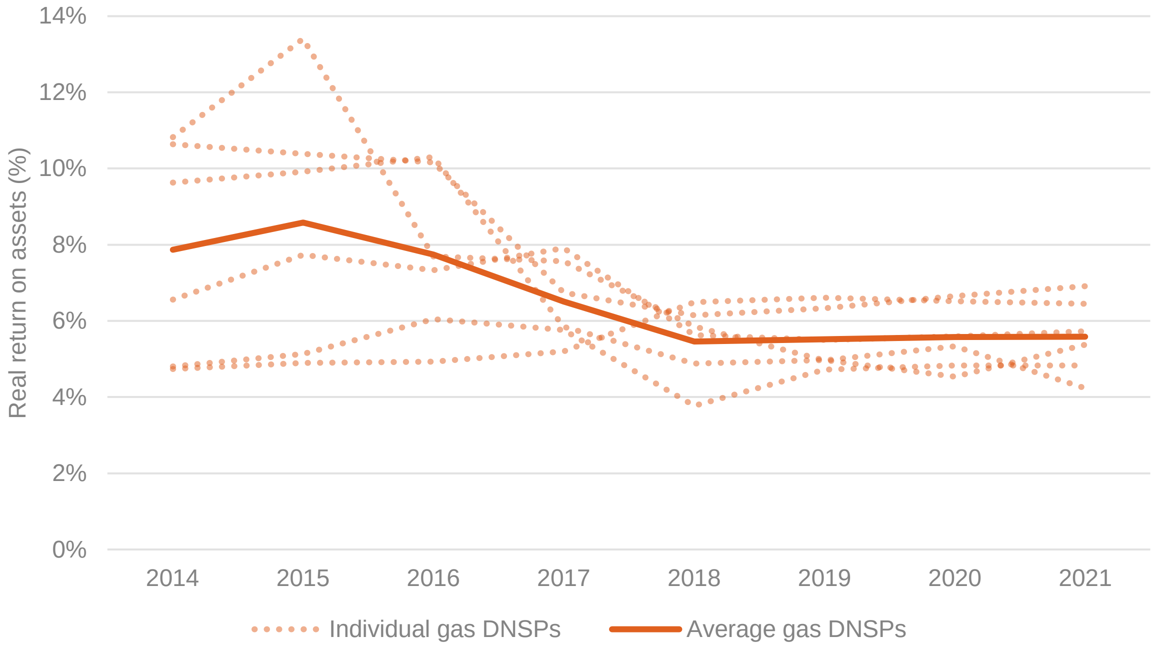
Amadeus' return on assets is confidential, so this section largely focusses on the other NSPs. Other metrics, such as return on regulated equity (Chapter 6), provide insight into Amadeus' profitability.

- On average, DNSPs consistently earnt a return on assets over 182 basis points higher than their average allowed return on capital since 2015. TNSPs (VTS and RBP) also consistently earnt a return on assets higher than the forecast allowed return on capital.
- Average returns on assets declined across the DNSPs over 2014–2021, which was driven in large part by lower allowed returns on capital. While VTS's returns on assets followed a similar downwards trend to the DNSPs, RBP's returns only started declining from 2018. In part, this reflects that RBP had its allowed rates of return reset relatively late under the 2013 rate of return guideline (see Figure 5-3).
- In 2021, real returns on assets declined slightly across DNSPs on average and for RBP – although they increased for VTS. Both DNSPs and TNSPs continued to generate returns greater than their allowed returns on capital.
- The average real return on assets experienced by gas DNSPs and TNSPs in 2021 were approximately 200 and 230 basis points above their allowed returns on capital, respectively.

Figure 5-1 and Figure 5-2 show how the regulatory returns on assets changed on average and individually for DNSPs and TNSPs over 2014–2021, respectively.

Figure 5-1 shows a relatively consistent downwards trend of regulatory returns on assets across DNSPs and on average.

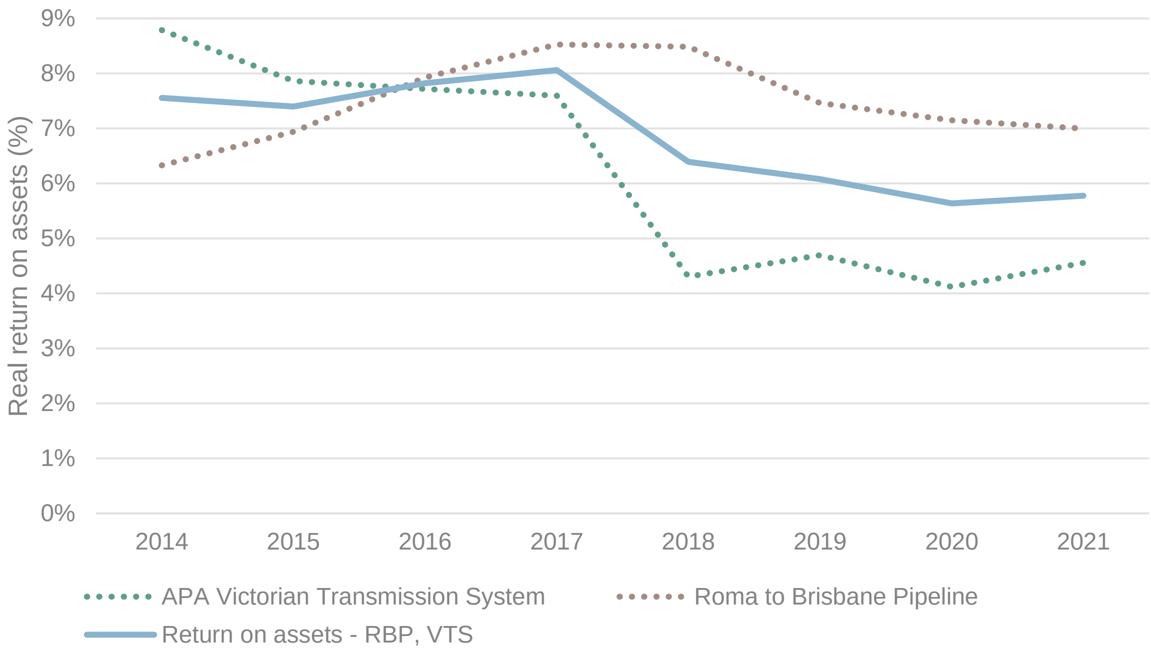
**Figure 5-1 Regulatory returns on assets – DNSPs**




Source: Financial performance data, AER calculation (detail provided in financial performance data and return on assets explanatory note), Average calculated as a simple average of individual DNSPs' return on assets.

Figure 5-1 also shows that the range of outcomes between the individual DNSPs has narrowed since 2018. This appears driven by a range of factors in combination. The most material factor appears to be the decline and convergence of allowed rates of return, which is a major driver of building block revenue.

**Figure 5-2 Regulatory returns on assets – TNSPs**




Source: Financial performance data, AER calculation (detail provided in financial performance data and return on assets explanatory note). Average calculated as a simple average of individual TNSPs' (excluding Amadeus') return on assets.

In contrast to DNSPs, Figure 5-2 shows that the returns on TNSPs' assets followed observably different trends:

- VTS followed a similar downward trend to the gas DNSPs, falling from 8.8% in 2014 to 4.6% in 2021.
- RBP trended upwards from 6.3% in 2014 to 8.5% in 2018 and has been trending down since to 7.0% in 2021.

Relative to 2020, the return on assets increased for VTS and decreased for RBP in 2021. This appears due to:

- Increased revenue for VTS
- Decreased revenue and increased expenditure for RBP.

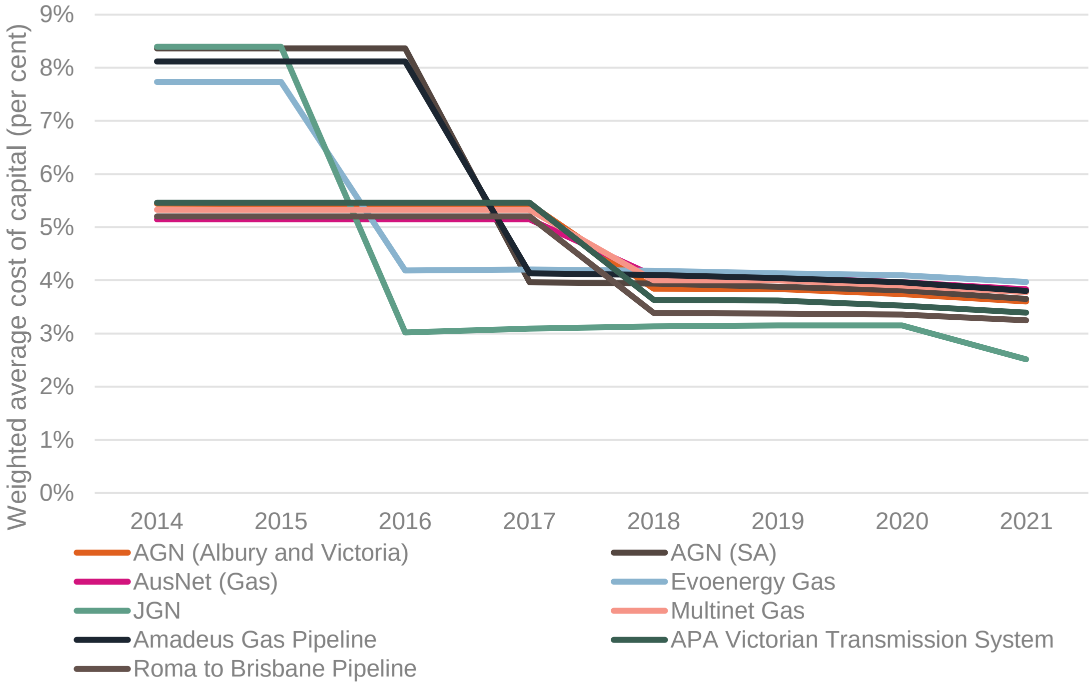
Figure 5-3 shows how the allowed real rate of return has changed among gas NSPs over time. It includes both gas DNSPs and TNSPs given there does not appear to be a systematic difference between distribution and transmission for this metric.

**Allowed returns on capital**

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 return on debt, for example, is made up of the amount of debt we forecast a benchmark efficient entity would hold (capital base multiplied by the benchmark gearing rate) multiplied by the allowed rate of return on debt. Equity is similar. We refer to the rates of return on debt and equity as 'allowed' returns.

After the 2013 rate of return guideline came into effect, allowed returns on debt were updated annually using a ten-year trailing average approach. This approach 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 ever five years. As such, allowed returns on capital in Figure 5-3 generally visibly change every five years for each NSP, and otherwise have had incremental annual changes since we started applying the 10-year trailing average approach.

**Figure 5-3 Forecast real weighted average costs of capital – NSPs**



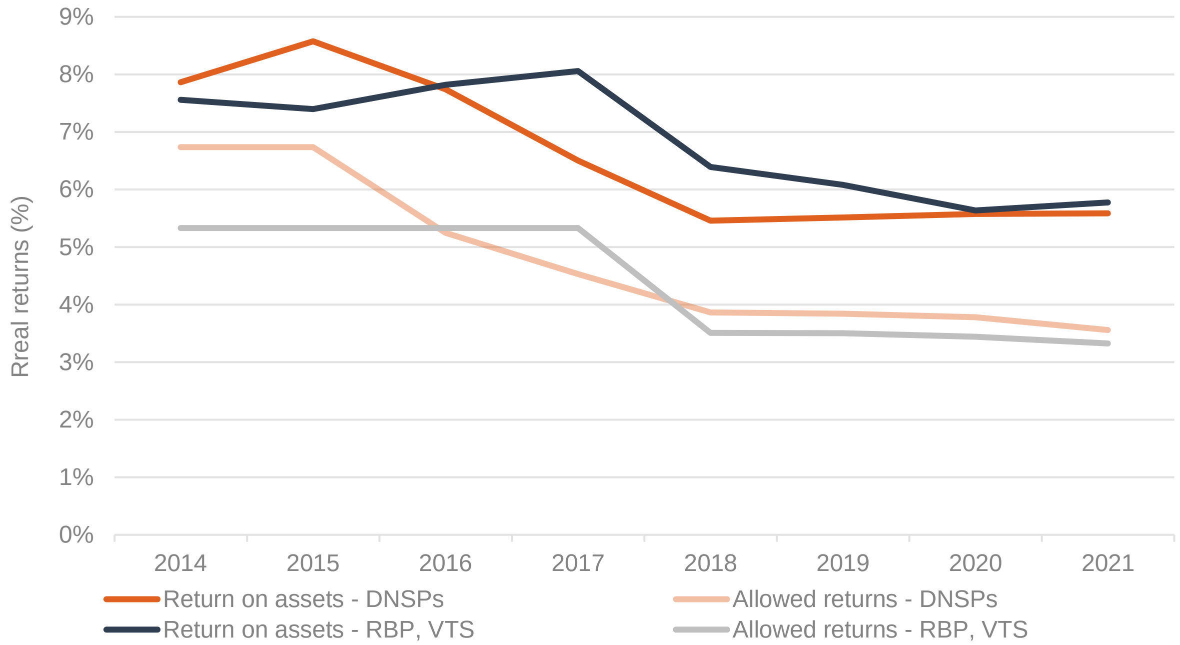

Source: Financial performance data – Summary – Gas DX/TX, original source: PTRM – WACC.

This observed convergence in the forecast rates of return shown in Figure 5-3 stems from:

- In decisions from 2015, returns on both equity and debt were reset under our 2013 rate of return guideline. In addition to changes to equity parameters, prevailing interest rates reflected in the forecast cost of debt and equity were materially lower than in the previous cycle of decisions.
- Under the trailing average portfolio return on debt approach, introduced in the 2013 guideline, the return on debt component of these allowed returns is updated annually. This reduces divergence relative to when each NSP's allowed return on debt for an access arrangement period (which differed between NSPs) was based on the benchmark cost of debt near the start of that period.
- In 2018 we made our first binding rate of return instrument. In the instrument, we made changes to both equity and debt parameters, contributing to further reductions in forecast rates of return. These applied first to JGN in 2021 and will apply in subsequent years to the other gas NSPs.

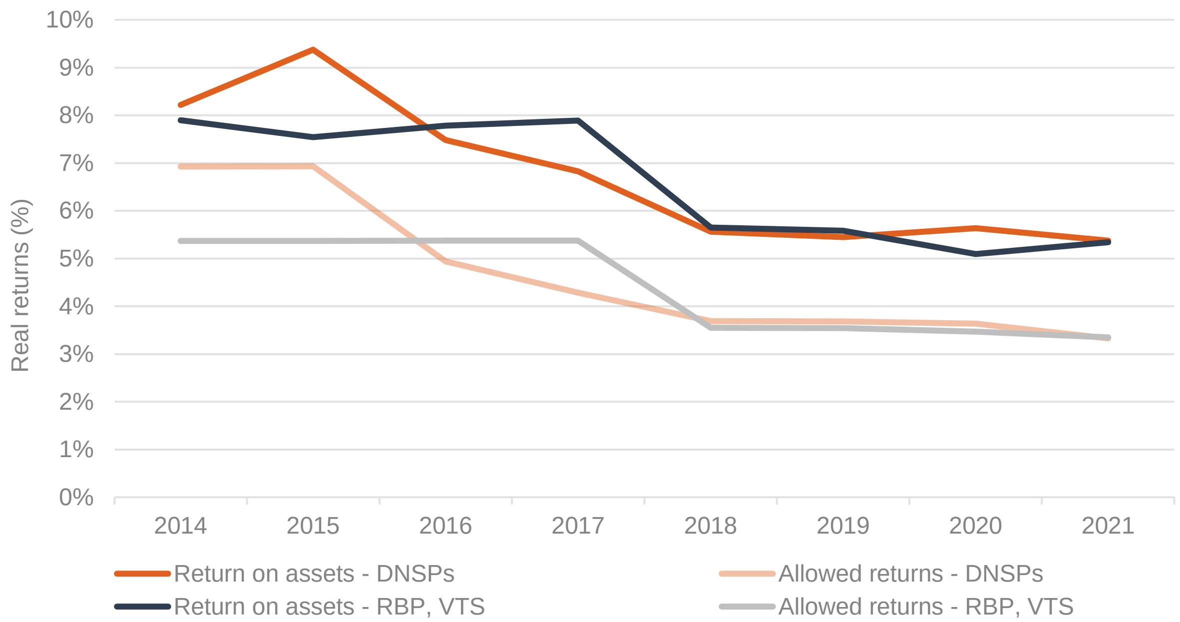
While actual and allowed returns have both declined, Figure 5-4 and Figure 5-5 show that both gas DNSPs and TNSPs have generated returns consistently and materially above allowed returns.

**Figure 5-4 Actual and allowed returns on assets – NSP simple average**




Source: Real WACC: PTRM – WACC. Average real return on assets: Financial performance data (model includes AER calculation, with more information in our return on assets explanatory note). Averages calculated as simple averages.

**Figure 5-5 Actual and allowed returns on assets – NSP weighted average**



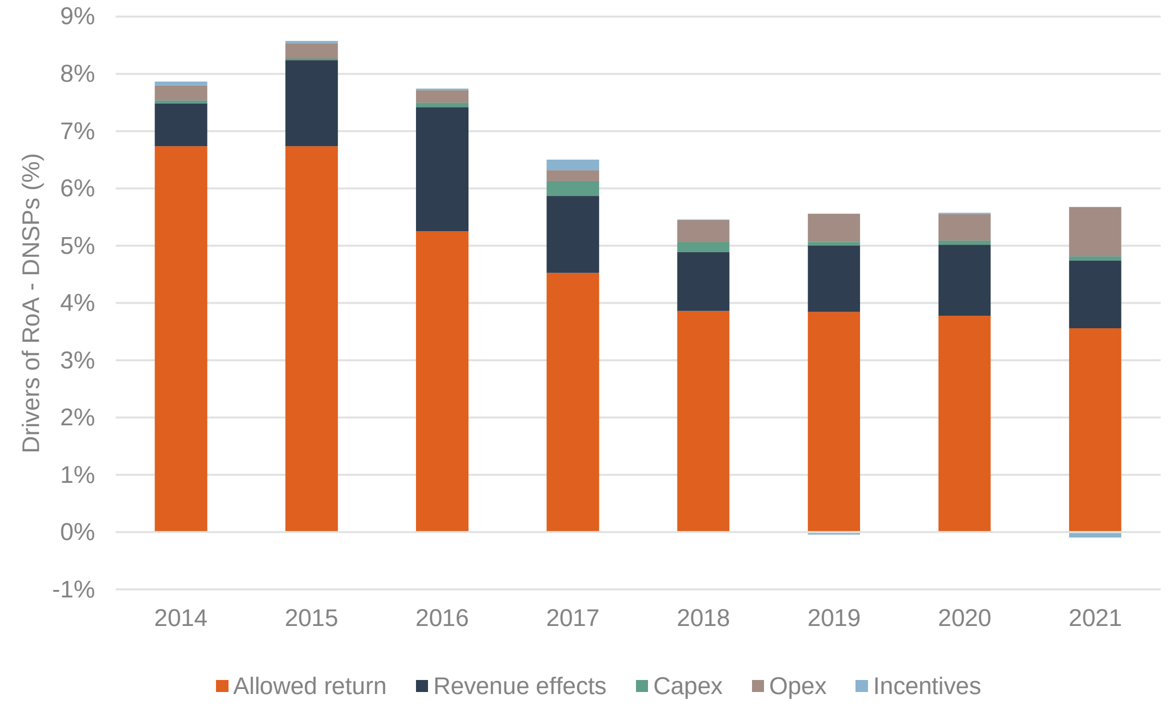

Source: Real WACC: PTRM – WACC. Average real return on assets: Financial performance data (model includes AER calculation, with more information in our return on assets explanatory note). Averages are weighted by the value of each NSP's capital base.

Allowed returns on assets has converged for gas DNSPs and TNSPs, while the difference in actual returns has increased. This was largely driven by changes in revenue. We observe that most DNSPs have experienced flat or decreasing revenues in 2021. In contrast, TNSPs have seen increases in revenue on average.

Our analysis in Figure 5-6 and Figure 5-7 suggests that this margin reflects several factors, including, in order of materiality:

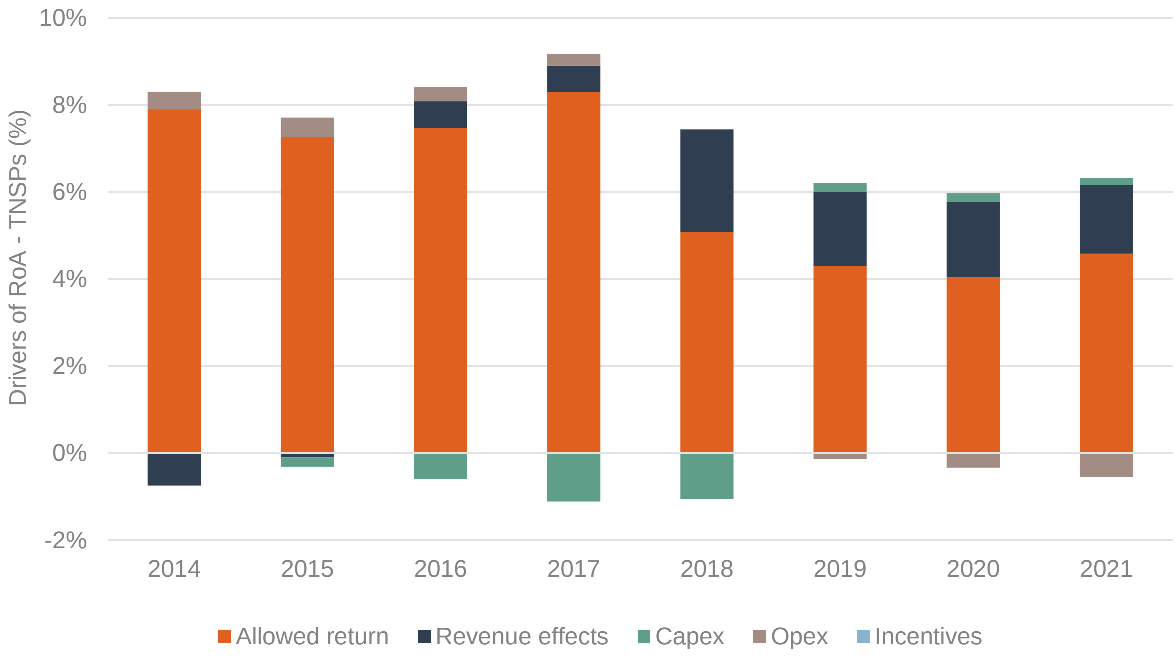
- What we collectively term ‘revenue effects’. For gas NSPs, this mainly reflects under or over recovery of revenue due to gas demand being lower or higher than forecast. Revenue effects can also include the effects of remittals and revenue smoothing. Revenue smoothing means that in any given year, unsmoothed revenue (that is, forecast expenditure) and smoothed revenue can materially differ—holding forecast demand constant. We calculate revenue effects as the residual difference between allowed returns on capital and actual returns on assets once we have stripped out the impact of outperformance due to incentive schemes and expenditure outperformance.
- Opex, which we calculate by substituting actual with forecast opex and calculating the incremental change in returns. Opex will contribute to a higher return on assets if NSPs underspend their opex allowance.
- Capex, which we calculate by substituting actual with forecast capex and calculating the incremental change in returns. Capex will contribute to a higher return on assets if NSPs underspend their capex allowance.
- Incentives, which we 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 NSPs spend less than their target opex (or capex where a CESS applies). This outperformance will contribute to lower expenditure allowances in the following period, thereby providing an incremental cost saving to consumers.

## Figure 5-6 Drivers of actual returns on assets – DNSPs




Source: Real WACC: PTRM – WACC. Average real return on assets: Financial performance data (model includes AER calculation, with more information in our return on assets explanatory note). AER calculation entails substituting forecasts of each factor with the actuals and calculating the incremental change in returns with each new factor for each network in every year of the time series. 'Revenue effects' are calculated as the remaining impact after accounting for the impacts of incentive schemes, opex and capex and predominately reflect volumetric outperformance.

## Figure 5-7 Drivers of actual returns on assets – TNSPs (excluding Amadeus)




Source: As per Figure 5-6.

## 5.2 EBIT per customer

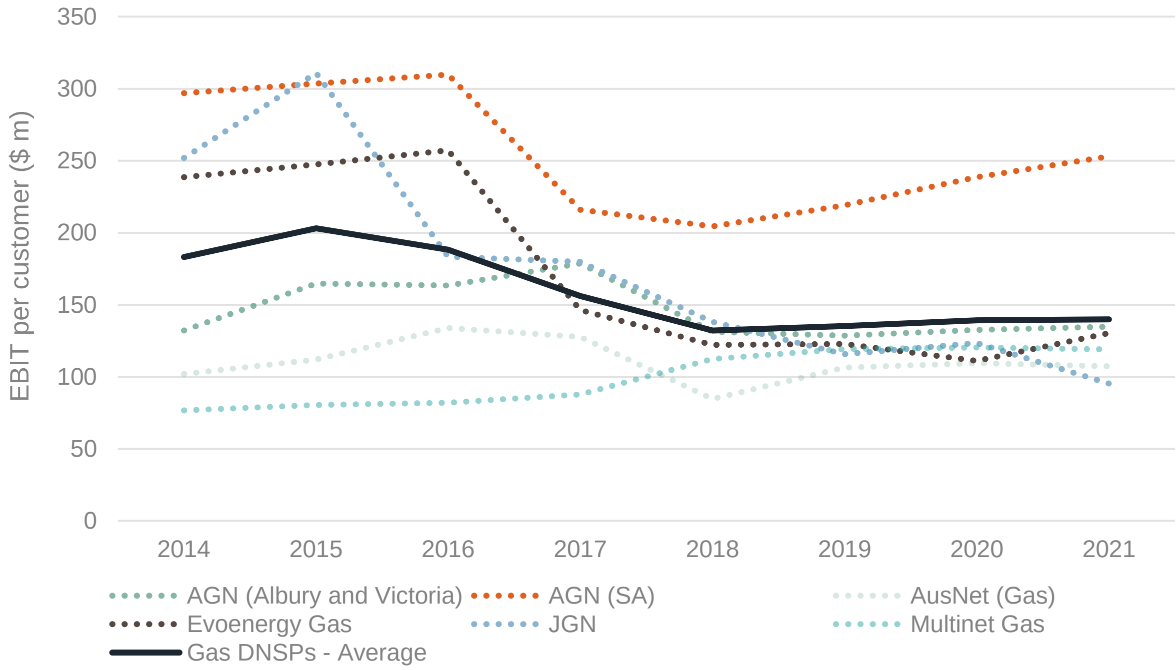
EBIT per customer is a measure of an NSP's operating profit divided by its consumer base. It is a complementary measure to the return on assets, capturing the same measure of profit (earnings before interest and tax, or EBIT) over a different cost driver.

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

We only report EBIT per customer for DNSPs as gas TNSPs 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 between TNSPs.

Figure 5-8 sets out the average real EBIT per customer, including incentive scheme payments and excluding the impacts of capital base indexation. In our view, this is the most informative single version of the EBIT per customer measure. It uses an estimate of EBIT that is computationally consistent with how real returns on assets are calculated.

**Figure 5-8 EBIT per customer – DNSPs**




Source: Financial performance data (model includes AER calculation, with more information in our EBIT per customer explanatory note). DNSP average is calculated as a simple average of each DNSP's EBIT per customer.

Over 2014 to 2021:

- Like the return on assets, EBIT per customer has declined on average, driven by lower allowed rates of return.
- The proportional decline is larger in EBIT per customer that the return on assets due to the growth in customer numbers over the same period.
- EBIT per customer has increased for AGN (SA) since 2018, reflecting the revenue required to cover its mains replacement program. While the Victorian networks also had large mains replacement programs, AGN (SA) was already this most capital-intensive DNSP, so the additional investment broadened a pre-existing gap.

## 5.3 RAB multiples

An NSP's RAB multiple is calculated as the NSP's enterprise value divided by its RAB (or capital base).[49] RAB multiples are a measure of investor expectations about a network's future returns and are widely used by market analysts in connection with regulated utilities. At the time of the relevant transaction, they are forward-looking, whereas profitability measures are based on historical outcomes. Since most of our regulatory approaches are predictable and set out in guidelines, we expect an environment where returns had been systematically insufficient would be evident in RAB multiples.

Several factors affect RAB multiples, some of which relate to the regulatory framework, whilst others relate to unregulated business activities. CEPA have been looking at disaggregating these factors as part of our 2022 rate of return instrument review.[50] Despite such complexities, advice Biggar gave when we developed the 2018 rate of return instrument indicates there is a "normal range" we might expect to see when observing RAB multiples:[51]

> *In my view, due to each firm's ability to earn rewards for taking desirable actions, an Enterprise Value (EV)/RAB ratio of slightly above one should be considered normal. This is consistent with the theoretical observation that the regulated firm must be left some "information rents" in an optimal regulatory contract. I therefore suggest that, as a starting point, an EV/RAB in the vicinity of 1.1 should be considered unobjectionable. In addition, due to uncertainties and complexities in the regulatory process, and in the process of estimating the EV and the RAB, I suggest an error margin of plus or minus twenty per cent on this figure could be considered a "normal range". I therefore suggest that an EV/RAB outside the range of 0.9-1.3 might give cause for further exploration and investigation.*

For these above reasons, we do not expect RAB multiples to be precisely at one under a well-functioning regulatory regime and consider that RAB multiples somewhat above one would not

49 The RAB of fully regulated gas NSPs is known as the capital base. We have referred to capital base as RAB in this section for simplicity.

50 CEPA, *EV/RAB multiples*, 10 May 2022

51 Darryl Biggar, *Understanding the role of RAB multiples in the regulatory process*, 2018.

necessarily indicate a problem. This is consistent with the approach followed by a range of other regulators that use RAB multiples as a reasonableness check or as relevant information on allowed rates of return.

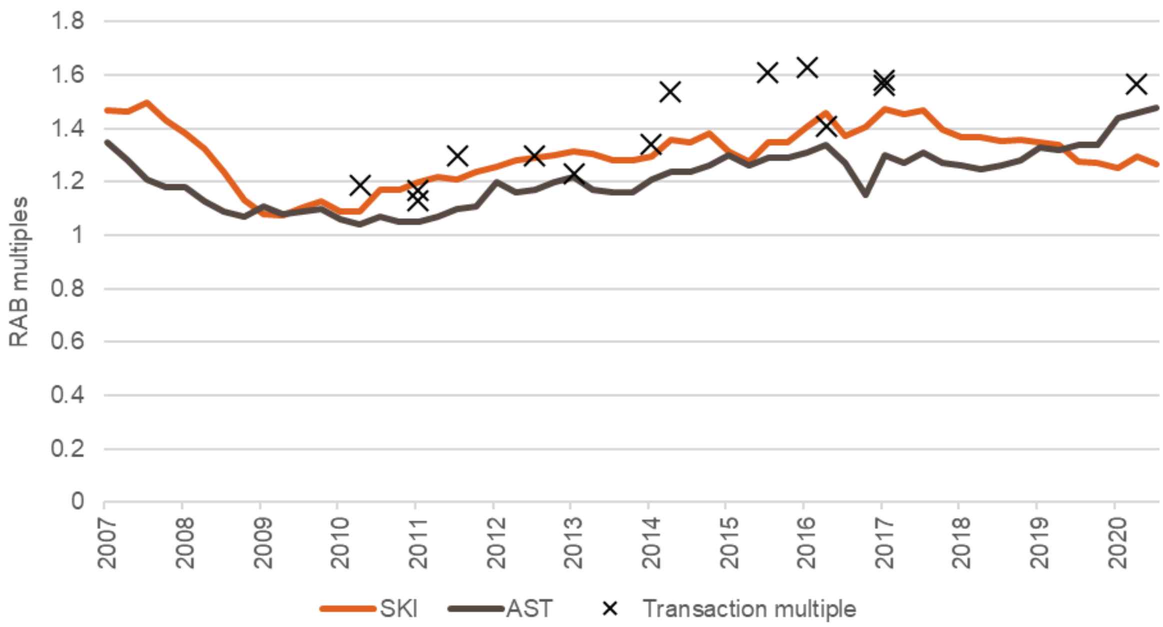
To draw on the largest possible body of market evidence, we have reported on two types of RAB multiples, sourced from Morgan Stanley:

- Transaction multiples – RAB multiples arising from the transaction of a discrete component of an ownership group including regulated NSPs.
- Trading multiples – RAB multiples generated using market value data on the enterprise value of publicly listed entities. The two relevant publicly listed entities, SKI (Spark Infrastructure) and AST (AusNet Services) were delisted from the Australian Securities Exchange (ASX) on 23 December 2021 and 17 February 2022, respectively. As such, we expect that no new relevant trading multiples will be available in the foreseeable future.

Further details of RAB multiples, including the implications of the measure are provided in the explanatory note for RAB multiples, which is published with this report.

Figure 5-9 combines our time series of both trading and transaction RAB multiples.

**Figure 5-9 AER regulated NSPs – transaction and trading multiples**




Source: Data from Morgan Stanley Research, AER analysis.

Note: SKI is Spark Infrastructure, which holds ownership stakes in SA Power Networks (49%), Victoria Power Networks (49%) and TransGrid (15%). AST is AusNet Services, which owns a Victorian electricity distribution network, electricity transmission network and gas distribution network.

The set of transaction multiples in Figure 5-9 captures a balanced mix of both electricity and gas networks held by the entities. The trading multiples mainly reflect ownership interest in electricity networks, with gas ownership limited to AusNet's ownership of its gas distribution network. We consider RAB multiples associated with both electricity and gas network ownership informative for understanding outcomes of regulation more broadly. This position reflects the overlap in our approaches to expenditure forecasting and determining rates of return when regulating gas and electricity networks.

While there are some differences between the regulation of gas and electricity networks, including differences in the form of control applied (that is, price caps versus revenue caps), there are many similarities. We have previously considered these similarities when determining that gas and electricity networks face similar levels of market risk. In our view, RAB multiples are part of a broader set of information assisting us to form insights about the sufficiency of returns achieved under both the gas and electricity regulatory framework. We consider in this context they are similarly applicable to both the fully regulated electricity and gas NSPs.

Despite the drivers of RAB multiples being difficult to quantify precisely, we have seen, for a number of years, the businesses we regulate traded at multiples well above 1.0. Further, we have seen vigorous competition among investors for these assets. In this context, it is difficult to conclude there is a material under-remuneration of investors. Rather, we consider RAB multiples indicate that investor expectations are that current and future returns from investing in those regulated assets are sufficiently high to remunerate their costs.

The most recent transaction multiple that involved a fully regulated gas DNSP was the purchase of the DUET Group in 2017, which owned Multinet Gas, for a transaction multiple of 1.56. This followed the purchase of Envestra in 2014 for a transaction multiple of 1.54, which owned the gas DNSPs now known as AGN (Albury & Victoria) and AGN (SA).

Unless there are more transactions of regulated NSPs, we do not anticipate there will be new information on RAB multiples next year as SKI and AST were delisted from the ASX with a final trading multiple of 1.27 in December 2021 and 1.42 in February 2022, respectively. In absence of new information, future network performance reports will likely reference previous analysis rather than include a standalone section on RAB multiples.

# 6 Focus area: Returns on regulated equity

Since 2020, we have collected information that allows us to report the return on regulated equity (RoRE) for NSPs. We started reporting on the RoRE for electricity NSPs in 2021. We are introducing RoRE for gas NSPs in this report.

The RoRE illustrates the final returns available to equity holders after all expenses. This allows the most comprehensive comparison of NSPs' actual returns against expected returns. Unlike the return on assets and EBIT per customer, RoRE is based on net profit after tax (NPAT) rather than EBIT. As such, it also captures returns arising from differences between an NSP's:

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

The RoRE is a complex measure and requires care to interpret. It reflects how our models and the building block revenue framework treat revenue and expenses—for example, valuing network assets using the capital base rather than a separate book or market value. Doing this makes the RoRE comparable against allowed returns on equity set in our access arrangement decisions.

However, for the above reason, our approach differs from how actual returns on equity would ordinarily be calculated. The distinct treatment of certain expenses in the regulatory model—for example, indexation of the capital base—makes it difficult to compare these estimates directly to statutory returns on equity included in annual reporting for listed companies. PwC has outlined the impacts of these differences in its advice for our profitability review.[52]

This section sets out our initial analysis of RoRE for gas NSPs alongside important background to help stakeholders interpret the results. We have published annual RoRE estimates for all fully regulated gas NSPs in our financial performance measures dataset. We encourage all stakeholders to review the results in this report and in our financial performance model alongside the following documents:

- Our profitability measures review final decision[53]
- The RoRE explanatory note published alongside this report.
- The illustrative RoRE model published alongside this report to illustrate the steps between calculating the return on assets and RoRE. These additional steps are not detailed in our actual financial performance data model due to confidentiality of the underlying data.
- PwC's summary of responses to our information request published alongside this report.

Further, the combination of the RoRE with the simpler return on assets should highlight different perspectives on profitability. This balances our reliance on these new and complex allocations with a simpler but less comprehensive measure.

52 PwC, *AER: Profitability measures review – Advice on the allocation of interest and tax expense*, June 2019.

53 In AER, *Profitability measures for electricity and gas network businesses*, accessed 15 August 2022.

## 6.1 How to interpret the return on regulated equity

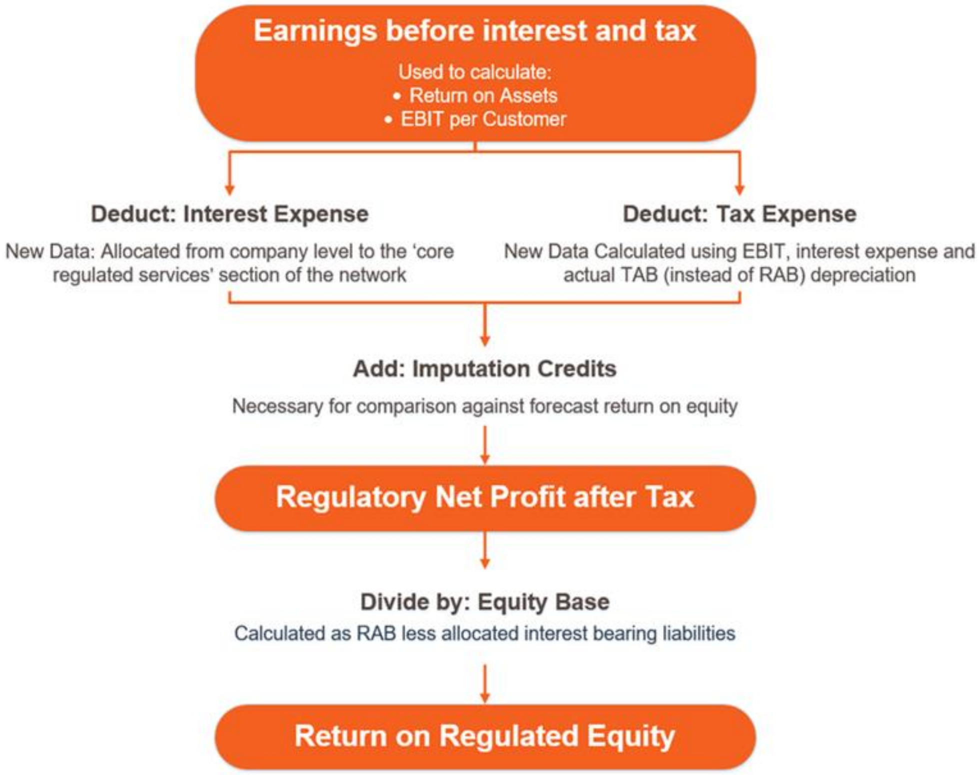
The regulatory framework is designed to provide NSPs with a reasonable opportunity to recover at least efficient costs they incur in providing reference services and complying with regulatory requirements.[54] This results in compensating NSPs in expectation for efficiently incurred costs such as opex, depreciation, interest on debt and tax. It also results in providing NSPs with an expected profit margin in line with the required return in the market for an investment of similar risk. If set at an appropriate level and supported by incentives, the expected profit margin should attract efficient investment. This is the role that the allowed return on equity plays.

NSPs' actual outcomes can differ from our forecasts and benchmarks. The revenue requirement is not a guaranteed return as NSPs' actual returns are determined in part by whether they spend more or less than these forecasts or depart from benchmarks. This type of regulatory framework is often described as an incentive-based framework, which aims to encourage NSPs to outperform the forecasts and be financially rewarded through higher returns. The opposite occurs if NSPs underperform against the forecast. If an NSP delivers its services at a lower cost than forecast, these lower costs should ultimately result in lower forecasts (holding other things constant) at the next access arrangement decision. Through this process, both consumers and NSPs share the benefits of efficiency gains over time.

Figure 6-1 illustrates how the RoRE builds on the information used to calculate the return on assets and EBIT per consumer.

54 National Gas Law, Clause 24(2) provides for this as part of the revenue and pricing principles.

**Figure 6-1 Simple illustration of the return on regulated equity measure**




Note: 'RAB' refers to the regulatory asset base, which we refer to as the capital asset base in this report.

Our regulatory framework is designed to target a real rate of return. That is, NSPs are compensated for actual inflation outcomes, preserving the purchasing power of NSPs and investors. To capture these components, we report both the:

- Real RoRE, which excludes inflation and is compared against the real post-tax return on equity
- Nominal RoRE, which includes inflation and is compared against the nominal post-tax return on equity

If we are calculating real returns, we make other adjustments so actual and allowed returns are comparable:

- To calculate the real return on assets, we remove indexation on debt and equity components of the capital base and inflate the opening capital base, so it is in common real dollar terms with EBIT.
- To calculate the real return on equity, which follows on from the return on assets, we add back the indexation on debt and only inflate the equity base (as opposed to the entire capital base) to be in common real dollar terms with regulatory NPAT.

As with our other measures, we have endeavoured to calculate the RoRE:

- At the NSP level rather than at the ownership group level. Many NSPs are held within a larger company structure along with other NSPs and/or other business units. Some expenses, such as tax and interest, are more commonly incurred at the ownership group level and not at the individual NSP's level. Due to this, we request further information on tax and interest expense.
- To show returns arising in providing reference services—that is, returns from providing the basic pipeline services using the capital base. The RoRE should not capture returns arising from unregulated other segments of the NSP.
- Treating revenue and expense drivers consistently with their use in PTRM.

We recognise there are practical challenges in calculating this information. Given these challenges, we sought PwC's advice on the reasonableness of the allocation approaches adopted by the NSPs. We have made a publishable summary of PwC's advice available on our website.[55]

A notable challenge is that some owners of NSPs issue debt and equity at the consolidated level, and do not necessarily assign capital issues to specific businesses within their portfolio. As such, some NSPs needed to estimate debt, interest and tax information using assumptions and judgement. This affected four of the nine NSPs. PwC advised that these:[56]

> *NSPs have utilised methods which allocate general corporate group debt based on a formula either having regard to regulated assets in comparison to book assets, or regulated revenue in comparison to group revenue. The explanations provided by the NSPs to support the allocation methodology in the BoP [basis of preparation] responses appear reasonable and in most instances have resulted in allocated gearing levels broadly consistent with the 60% benchmark gearing ratio applied for regulatory purposes. Where gearing ratios depart from the 60% benchmark rate, this appears to be reflective of the differential in the actual gearing levels adopted by relevant NSP in relation to the regulated assets*

In its review, PwC commented on the approach to estimating tax and interest data, which was generally reasonable. PwC commented on our approach to removing the impact of historic capital base indexation by using depreciation in the tax asset base. While PwC supports removing historic indexation, it advised that our adjustment approach would also capture deprecation of customer contributions and gifted assets, which should not impact the effective tax rate. We have maintained our approach as it is a reasonable method for making the required adjustment. PwC advised that any errors are unlikely to be material at this time, but we should continue to monitor these effects[57].

55 Published alongside this report as: PwC, *Appendix A – High level publishable summary: Review of the gas NSPs' responses to the AER's profitability measures information request*, 30 June 2022.

56 PwC, *Appendix A – High level publishable summary: Review of the gas NSPs' responses to the AER's profitability measures information request*, 30 June 2022.

57 PwC, *Appendix A – High level publishable summary: Review of the gas NSPs' responses to the AER's profitability measures information request*, 30 June 2022, pp. 3–5.

## 6.2 Key findings

The following sections set out our key findings on the RoRE and its drivers based on:

- Real returns—that is, excluding returns from indexation of the equity base
- Returns including rewards or penalties from incentive schemes

Our financial performance data, published alongside this report, allows stakeholders to adjust the above settings and compare actual returns to allowed returns.

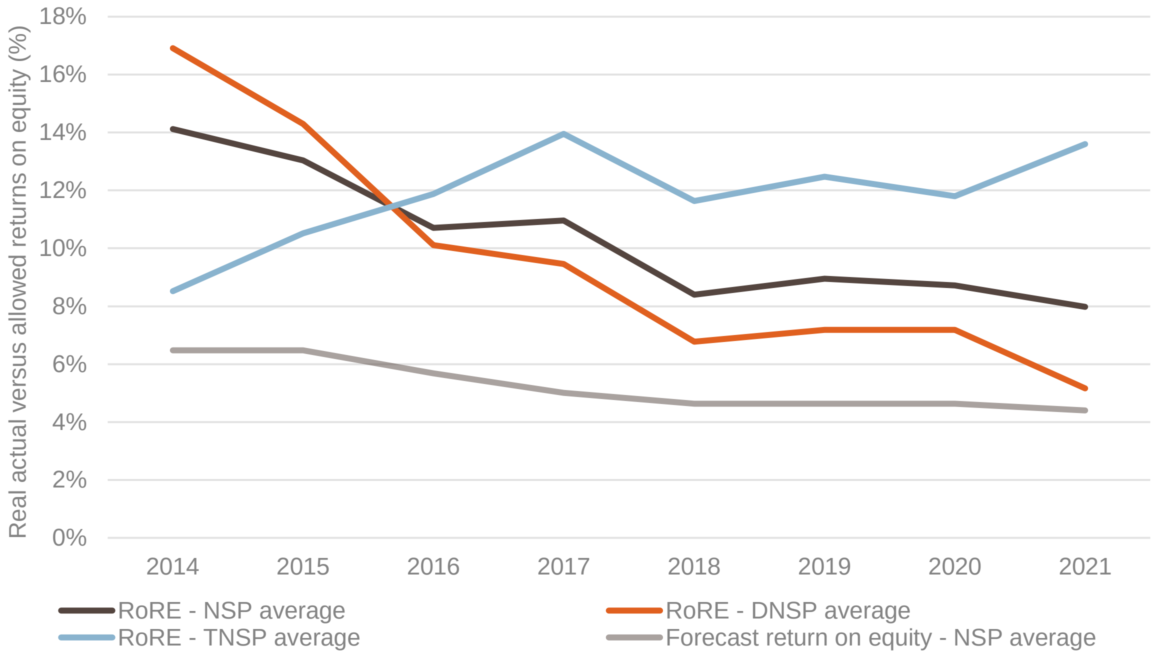
### 6.2.1 What returns are networks achieving?

- NSPs in general faced declining RoREs over 2014 to 2021. This is consistent with our returns on assets estimates, giving us some confidence in the results. When a simple average is taken, TNSPs provide an exception. This reflects the high RoRE achieved after 2016 by smallest TNSP, Amadeus.
- When we weight the average RoRE by equity holdings, RoRE measures follow a more of a downwards trend across NSPs. This suggests some firm-specific factors affected smaller NSPs, and materially influenced RoRE when calculated as a simple average.
- NSPs consistently achieved RoREs that exceeded allowed returns on equity on average.
- This occurred against a backdrop of declining allowed returns on equity, which progressed as interest rates declined and we started applying the 2013 rate of return guideline and, from 2020, the 2018 binding rate of return instrument.
- Actual returns on equity in 2021 are sitting at about 357 and 179 basis points higher than allowed returns on equity on a simple and weighted average basis, respectively.

Figure 6-2 and Figure 6-3 shows that over 2014–2021, fully regulated gas NSPs have on average achieved higher RoREs than forecast. We present RoRE as an average for TNSPs, DNSPs and all NSPs. Given DNSPs and TNSPs received similar allowed returns on equity, we only present that measure on an NSP-wide basis.

Figure 6-2 presents the RoRE as a simple average (that is, each NSP's RoRE is weighted equally). In effect, this illustrates how NSPs performed on average. The RoRE consistently fell for DNSPs but has fluctuated for TNSPs, including an increase between 2016 and 2018.

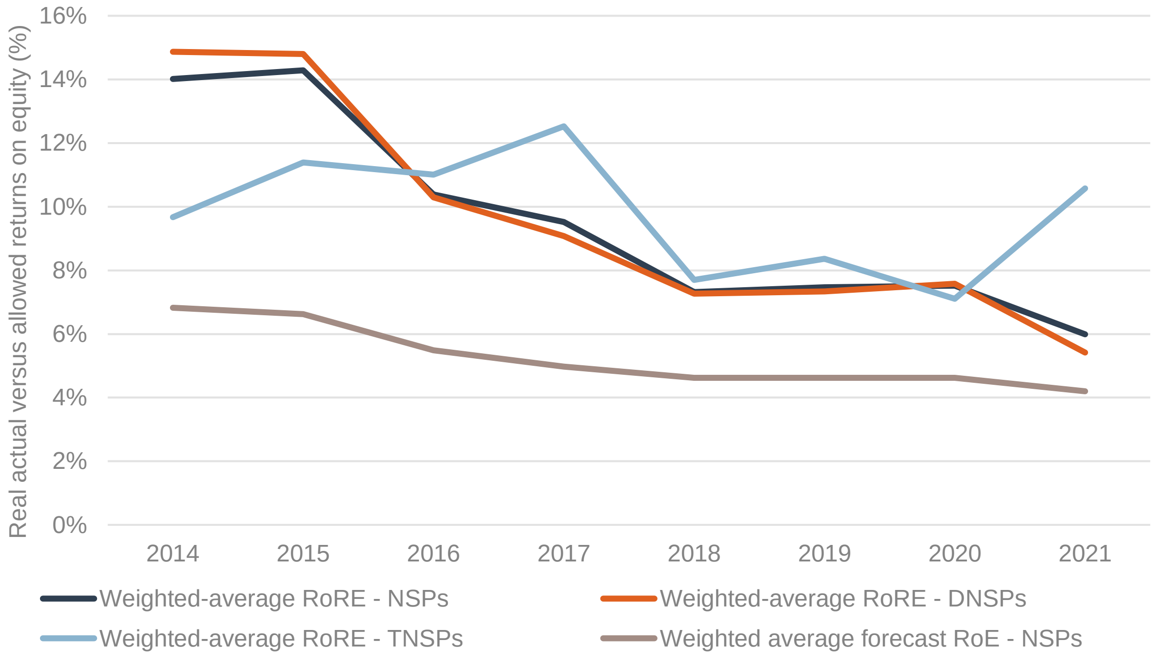
**Figure 6-2 Real RoRE compared to allowed returns on equity – simple average**




Source: Financial performance data – Summary Gas Dx/Tx, return on equity (model includes AER calculation, with more information in our return on regulated equity explanatory note). Averages are calculated as simple averages.

Figure 6-3 presents RoRE as an average weighted by each NSP's regulated equity– that is, larger NSPs typically receive greater weight. In effect, this illustrates the average return on equity invested into fully regulated gas networks. If smaller NSPs receive systematically higher or lower returns on equity, the weighted average RoRE will differ from the simple average RoRE.

**Figure 6-3 Real RoRE compared to allowed returns on equity – weighted average**




Source: Financial performance data – Summary Gas Dx/Tx, return on equity (model includes AER calculation, with more information in our return on regulated equity explanatory note). Averages are calculated as weighted averages according to the total level of equity.

Figure 6-3 indicates that the average RoRE invested into regulated gas networks has consistently been greater than forecast since 2014. However, both allowed returns on equity and actual RoRE have declined, and the gap between allowed and actual returns on equity has visibly narrowed. It is also worth acknowledging that underneath the average results, there is a spectrum of outcomes between NSPs.

Whether these results are evidence of the framework operating effectively or not depends on the drivers of the results, including whether they are caused by:

- Temporary revenue over-collections which will be passed back to consumers in the short-term. For example, the revenue smoothing we apply when estimating NSPs' revenue recovery paths will result in temporary revenue over- and under-recovery, which evens out over time.
- Departures from our benchmark financing structures, which do not result in consumers paying more for reference services. Rather, these reflect that some NSPs have chosen to take on higher risk to achieve higher returns for themselves.
- NSPs spending less than forecast revenue building blocks due to efficiency gains.
- NSPs spending less than forecast revenue building blocks due to forecasting errors. Forecasting errors might be due to genuinely unforeseen circumstances, such as an unexpected decision of a major user to connect or disconnect from the network. Forecasting errors may also be due to shortcomings in our approach to estimating network revenue requirements, such as an overestimate of input costs.

In the following sections, we set out our analysis of these factors that have driven differences between allowed returns and what NSPs have achieved.

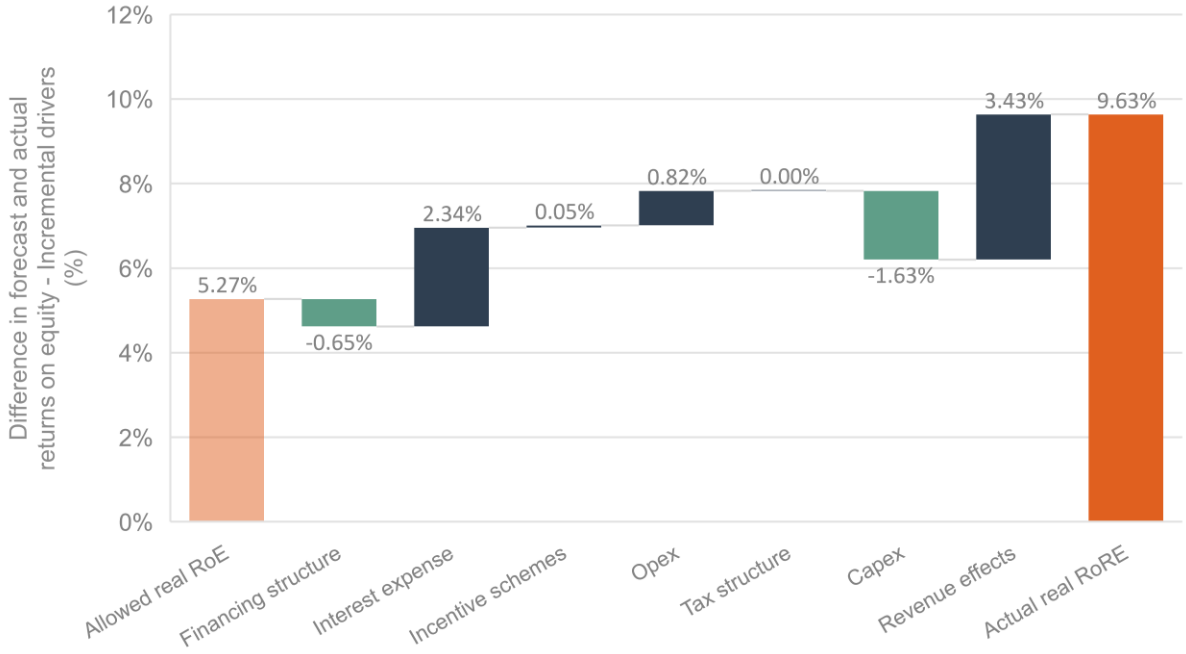
### 6.2.2 What is driving these results?

Our analysis suggests that the differences between forecast and actual returns on equity is driven by a combination of factors. The following figures set out the average impact of different drivers in explaining the margin between actual real RoRE and the benchmark allowed real return on equity.

Figure 6-4 and Figure 6-5 show these drivers as simple averages over 2014–21. These long-term averages are informative, but should also be considered alongside:

- More recent return drivers (Figure 6-6 and Figure 6-7 present this data for the 2021 regulatory year rather than as averages since 2014).
- How different factors have changed throughout the reporting period more broadly. See the following sections for a more thorough and nuanced analysis. For example, while the average contribution of incentive schemes on the RoRE is 0.00% for TNSPs because we do not apply incentive schemes to gas transmission, it nets off to 0.05% for DNSPs due to it varying over time from positive (rewards) to negative (penalties) (discussed in Section 6.9)

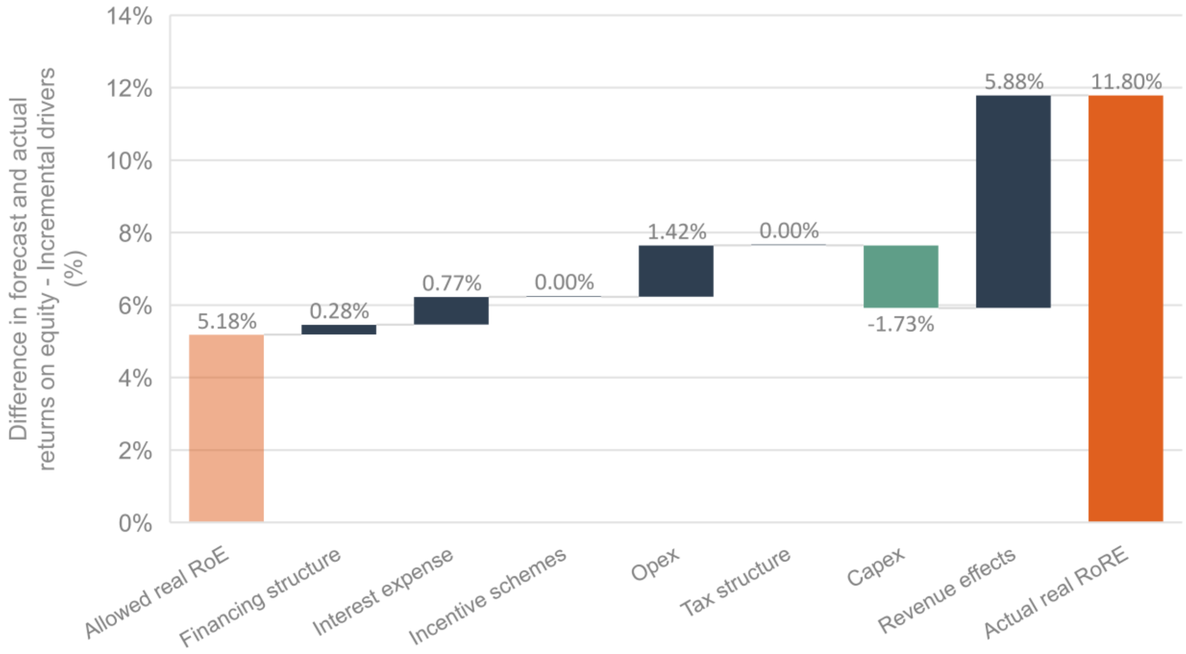
## Figure 6-4 Incremental contributions to RoRE over 2014–21 – DNSPs




Financial performance data (confidential version). AER calculation of incremental contributions to RoRE.

Note: We have calculated the above by substituting our benchmark allowance for each factor in place of the actuals. For example, we have substituted in forecast opex from our PTRM in place of actual opex used in calculating the real RoRE. We calculate the incremental change in returns with each new factor for each network in every year of the time series and take a simple average across all NSPs.

## Figure 6-5 Incremental contributions to RoRE over 2014–21 – TNSPs

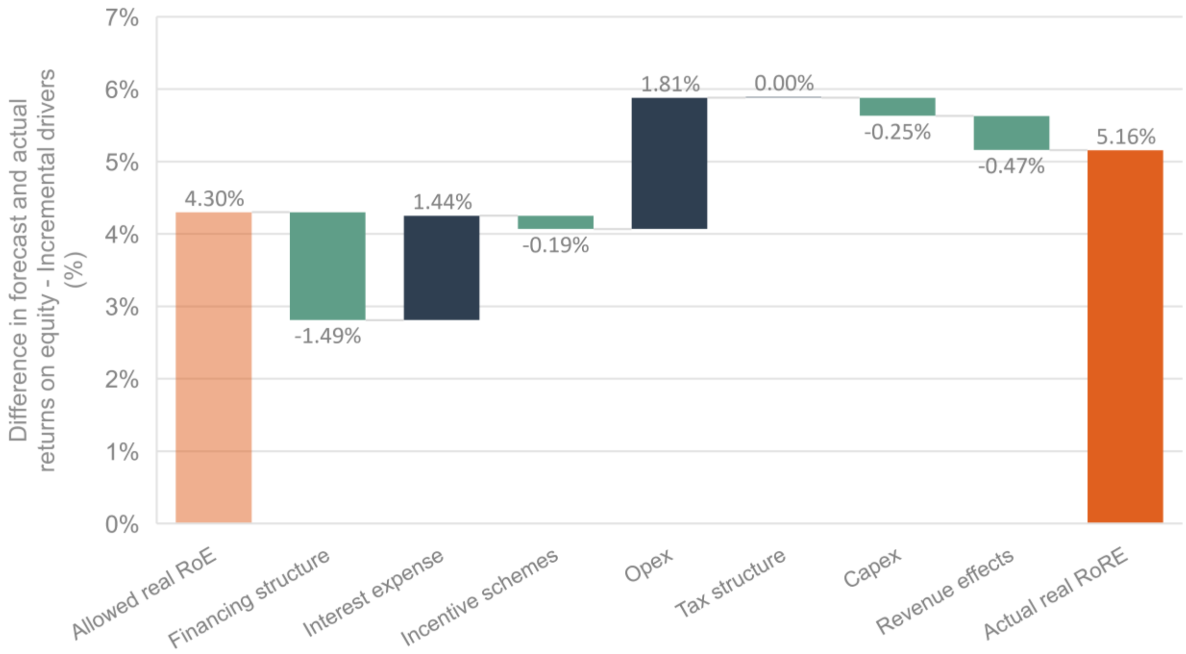



Source: Financial performance data (confidential version). AER calculation of incremental contributions to RoRE.

Note: As per Figure 6-4.

Figure 6-6 and Figure 6-7 show the previous waterfall charts for the 2021 regulatory year only.

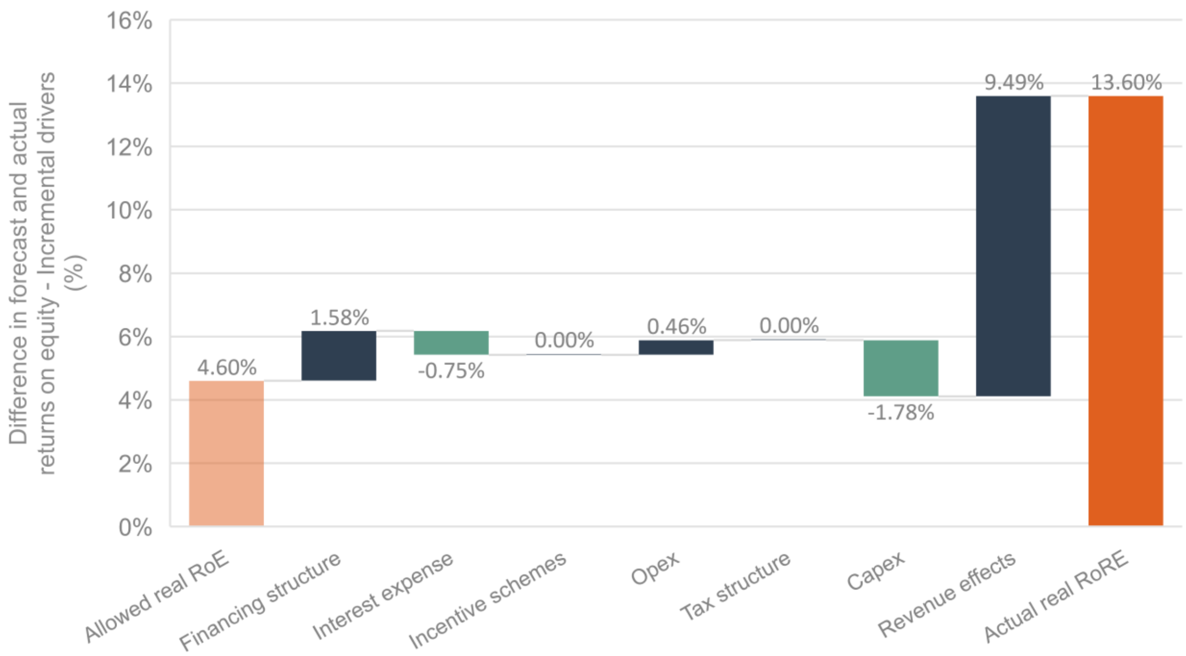
### Figure 6-6 Incremental contributions to RoRE in 2021 – DNSPs




Source: Financial performance data (confidential version). AER calculation of incremental contributions to RoRE

Note: As per Figure 6-4 but calculated as the simple average across DNSPs in 2021 only.

### Figure 6-7 Incremental contributions to RoRE in 2021 – TNSPs




Source: Financial performance data (confidential version). AER calculation of incremental contributions to RoRE

Note: As per Figure 6-5 but calculated as the simple average across TNSPs in 2021 only.

Figure 6-4 and Figure 6-5 illustrate differences in what has driven the RoRE for DNSPs and TNSPs over 2014–2021, and Figure 6-6 and Figure 6-7 show this these differences for 2021. Notable differences include:

- Revenue effects had a larger positive impact for TNSPs over the period, and a notably higher impact in 2021. This is due to the following:
    - Revenue effects are largely driven by actual demand differing from forecasts, which has occurred to a greater extent for TNSPs. There are several plausible reasons for this outcome, which would be valuable to explore in future reports. Some of these reasons stem from TNSPs predominantly transporting gas to a small number of large consumers for use in generation or industrial activities. Due this:
        - Demand for TNSPs would likely be more challenging to forecast as one unexpected connection or disconnection could materially change demand.
        - TNSPs may have greater scope to structure tariffs and services in innovative ways to stimulate demand as large gas users are relatively price sensitive and better placed to engage with sophisticated service offerings. Related to this, we have observed that some TNSPs are more likely to collect revenue through non-reference services.
    - Revenue effects also include revenue adjustments due to remitted regulatory decisions. Due to a remittal, JGN had a large negative revenue adjustment in 2021, which materially lowered the average contribution of revenue effects towards the DNSPs' RoRE in 2021.
- Interest expense had a larger positive impact for DNSPs both over the period and in 2021. This would typically indicate that DNSPs were more successful in raising debt at lower rates than TNSPs. In practice, all three TNSPs are owned by APA Group, which mostly owns and operates unregulated pipelines and raises debt at the group level. As such, assumptions were required in determining what interest-bearing liabilities and expenses to attribute to APA Group's regulated entities. Consequently, the proportion of the TNSP capital base financed with interest-bearing liabilities, and the interest rates incurred by TNSPs reflect APA Group's corporate averages, and so should be interpreted with caution.
- Financing structure had a positive impact on TNSPs and a negative impact on DNSPs, both in 2021 and as an average over 2014–2021 (although the magnitude of this impact was larger in 2021). Financing structure refers to the proportion of the capital base financed with interest-bearing liabilities, so this effect for TNSPs also reflects APA Group's corporate averages and should be interpreted with caution.

## 6.3 Revenue effects (including demand outperformance)

All fully regulated gas NSPs are regulated under a 'weighted average price cap' form of control. They therefore experience less temporary revenue effects than electricity NSPs, which are regulated under revenue caps that adjust for revenue over and under recoveries over time.

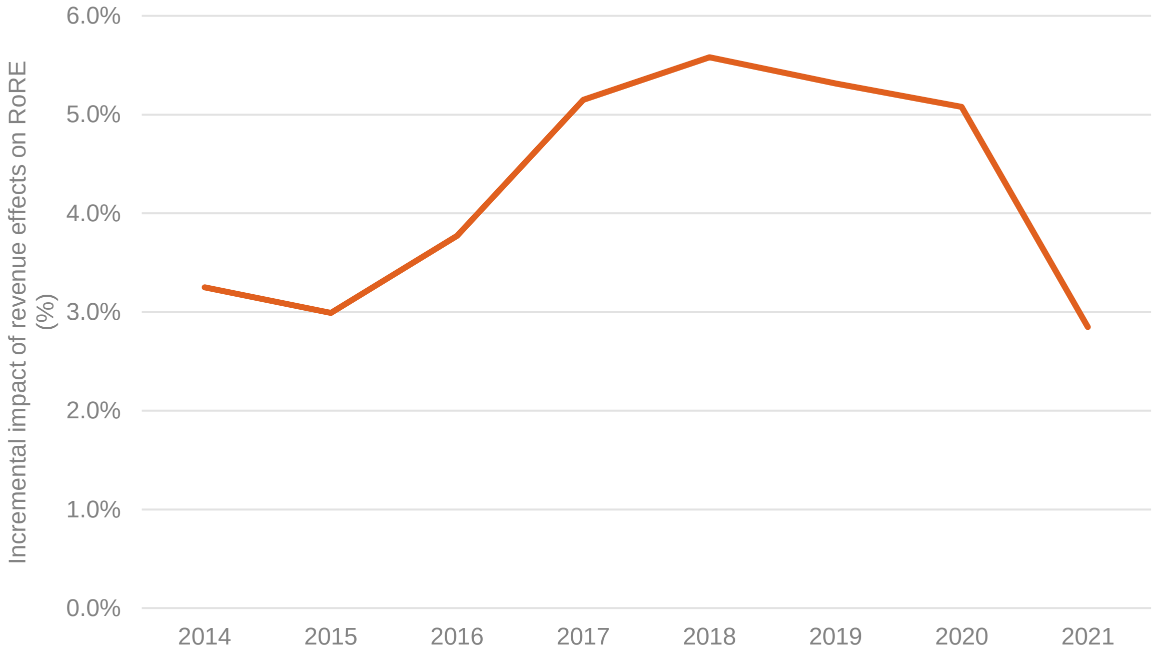
However, by being regulated under weighted average price caps, gas NSPs can earn above or below forecast revenue over time due to changes in demand. Differences between forecast and actual demand in any year can result in higher or lower returns for NSPs, which NSPs keep – notwithstanding that demand forecasts next period will be influenced by previous actuals. Our analysis indicates that this effect has been material as gas demand has exceeded forecasts, contributing to higher than forecast revenue recovery (discussed previously in section 4.1.4).

While, in our view, differences between forecast and actual demand would be the strongest contributor to revenue effects, gas NSPs 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.

Over 2014 to 2021:

- Revenue effects accounted for 4.2 percentage points of the average difference between NSP returns and allowed returns – and accounted for 2.43 percentage points of this difference in 2021.
- Prior to 2021, there was a continual upward trend of revenue effects. This year, while still having a positive effect, revenue effects dropped 2.9 percentage points, reflecting that revenue outperformance among most DNSPs was lower than the previous year.

**Figure 6-8 Impact of revenue effects through time — NSPs**




Source: Financial performance data (confidential version). AER calculation of revenue effects through time (difference between real and forecast RoRE minus the sum of the incremental impact of each other parameter). Averages throughout are calculated as simple averages.

The impact of revenue effects was at its peak in the latter years, however had a decrease in 2021. This appears to be largely driven by NSPs outperforming revenue forecasts by a lesser extent than in 2020.

## 6.4 Impact of interest expense

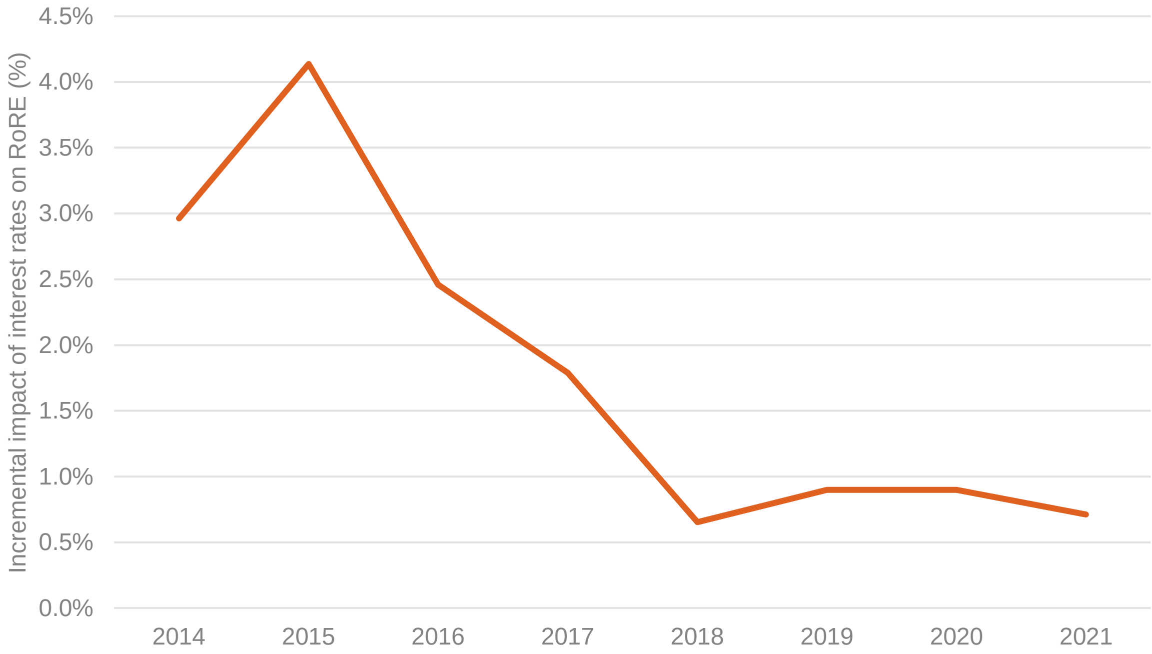
NSPs raise capital (debt and/or equity) to finance investment in their assets. They are compensated for these costs through the return on capital building block, which includes a return on debt to compensate NSPs for the interest that an efficient benchmark entity would incur.

NSPs may raise debt at higher or lower rates than allowed returns on debt, which are an estimate of what a benchmark efficient entity would incur. Our estimated RoRE increases where NSPs raise debt at lower rates than this benchmark and decreases where rates are higher than this benchmark. Consumers only contribute to the estimated efficient cost of raising debt, and do not bear any risks or costs of either outperformance or underperformance against this benchmark rate.

Over 2014 to 2021, we find that:

- NSPs generally raised debt at rates below the allowed return on debt, which contributed towards them consistently achieving higher returns. In 2021, interest rates had a small positive incremental impact on the RoRE of 0.71 percentage points.
- While the magnitude of interest rates' impact has varied through time, it has been following a clear downward trend.

**Figure 6-9: Impact of NSPs' actual interest rates differing from allowed returns on debt**



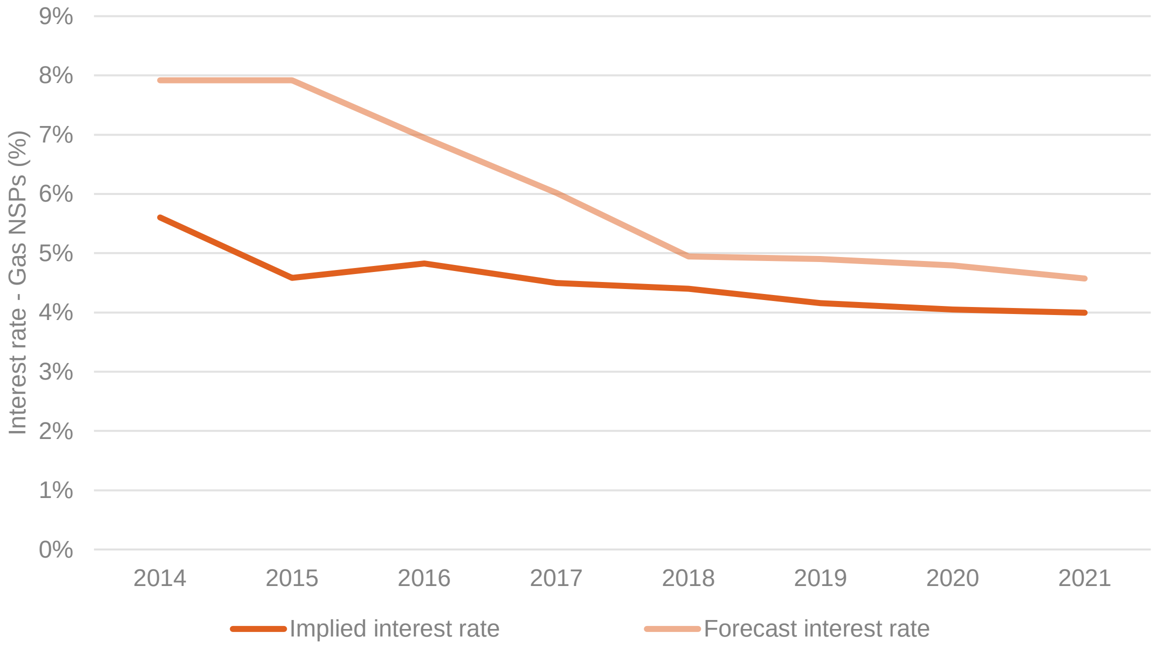

Source: Financial performance data (confidential version). AER calculation of difference between actual real RoRE with and without forecast interest rates. Averages throughout are calculated as simple averages.

The positive incremental impact has been decreasing, although the average interest rate has been below forecasts in all years of the measurement period. Figure 6-10 shows that the margin between gas NSPs' interest rates and the forecast interest rate (expressed as the allowed return on debt) has narrowed over time.

For completeness, the implied interest rates in Figure 6-10 differ from the Energy Infrastructure Credit Spread Index (EICSI), which informs the return on debt allowance and is also based on NSP debt data. Unlike the implied interest rates below that are based on gas NSPs, the EICSI is calculated using all non-government owned NSPs. Among other differences, the EICSI is also calculated as a credit spread (that is, the premium above the bank bill swap rate) and is weighted by tenor.[58]

58 AER, *Explanatory statement: Draft rate of return instrument*, June 2022, p. 205; AER, *Energy network debt data: Final working paper*, November 2020, p. 9.

**Figure 6-10 Comparison of forecast and actual interest rates — NSPs**




Source: AER calculation of difference between the forecast interest rate (allowed return on debt) and the implied interest rate (data from confidential information request). Averages throughout are calculated as simple averages.

**How do we estimate actual interest rates?**

In responses to our information request, NSPs allocated for each year:

- The interest expense arising in that year—that is, the interest the NSP paid on its debt
- The value of interest-bearing liabilities giving rise to that debt—that is, the amount of debt held by the NSP

From that information, we estimated an effective interest rate on the portfolio of debt allocated to that NSP.

In our view, these results reflect a complex set of changes in market circumstances and our approach to forecasting rates of return on debt:

- In 2014 and 2015, most networks' allowed returns on debt were still based on decisions made in 2009 and 2010 when interest rates were significantly higher. At that stage, returns on debt were set using the 'on the day' approach and, as a result, resets occurring in a high interest rate environment would materially increase the networks' forecast interest rates across their entire portfolios of debt.

- Over 2014 to 2018 we completed resets for most gas NSPs and reset returns on their portfolio of debt in a lower interest rate environment. This explains the rapid decline in average forecast costs of debt.
- This also marked the commencement of transitions to a trailing average portfolio return on debt, after which the rates on NSPs' portfolios of debt were and continue to be updated annually for a tranche of debt.
- In our 2018 binding rate of return instrument,[59] we found that our approach to targeting the benchmark credit rating was resulting in higher than necessary annual estimates of the cost of debt, so made changes in response.

Our approach to forecasting interest rates, along with other elements of the rate of return, is currently being considered under our 2022 rate of return instrument review.[60]

## 6.5 Impact of financing structure

When we set allowed returns on capital, we apply a benchmark assumption that NSPs raise 60% of their capital as debt and finance the remaining 40% as equity. We refer to this as the NSP's 'gearing'. In doing so, we recognise that NSPs can choose to depart from the benchmark. For example, an NSP may finance a higher proportion of its capital requirements using debt, and a smaller proportion through equity. Then, when profit is available to be distributed, the profits are distributed across a smaller base of equity ownership, resulting in higher returns per dollar of equity invested.

By departing from the benchmark in this way, NSPs are taking on extra risk to achieve higher reward. Where NSPs raise more debt than our benchmark, equity holders are more exposed to changes in other drivers of revenue and costs because of the smaller equity base over which the impacts are distributed. The opposite is true if an NSP chooses to raise less debt than our benchmark.

For this reason, higher or lower returns arising from different financing structures are not necessarily a problem and do not represent a cost to consumers. Over time, a broader pattern of differences between our benchmark and actual practices may cause us to revisit our benchmark to reflect any change to revealed efficient behaviours.

59 AER, *Rate of return instrument—Explanatory statement*, December 2018.

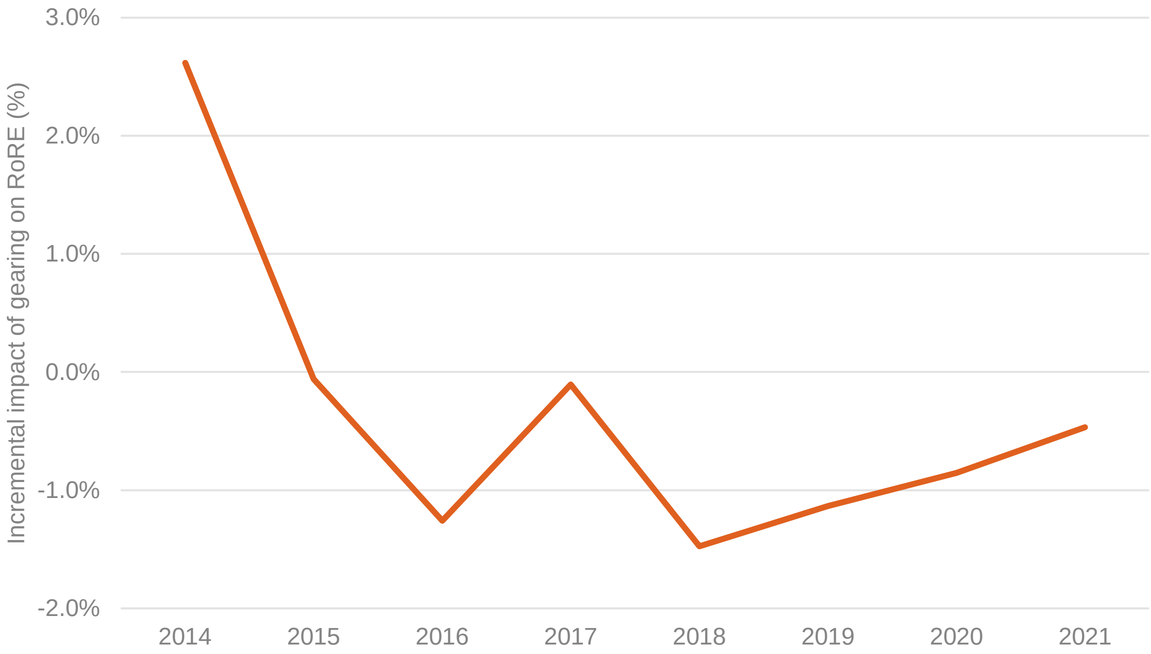
60 AER, *Rate of return instrument 2022*, accessed 23 September 2022.

Over 2014 to 2021, we find that:

- There is a mix of financing strategies between NSPs and a wide range of gearing levels.
- Returns are highly sensitive to financing strategy. Higher gearing amplifies the impacts of other differences between forecast and actual revenues or expenditures. The combination of most NSPs having somewhat more debt than benchmark in 2014–2015 and the high sensitivity of results to financing structure is why this had a positive impact on the RoRE at the start of the measurement period.
- Financing structure has less of a positive impact over the period after we adjust interest-bearing liabilities downwards following the sale of NSPs at a premium to the capital base (see the explanatory box below on how we adjust for this premium).

Figure 6-11 shows that the impact of financing structure has had less of an impact on the RoRE over time. However, these results are materially affected by an adjustment we make to NSPs' interest-bearing liabilities in the regulatory year after they were sold at a premium to the capital base. This resulted in a downwards correction to the debt holdings used to finance AGN (SA)'s and AGN (Victoria and Albury)'s capital bases in 2016 and 2015, respectively. For further explanation, see 'why and how we adjust for goodwill' in the explanatory box below.

**Figure 6-11 Impact of financing structure through time — NSPs**




Source: Financial performance data (confidential version) after applying the goodwill adjustment to debt holdings. AER calculation as the difference between real RoRE with and without benchmark gearing. Averages throughout are simple averages.

**How we estimate actual equity and gearing**

In responses to our information request, each NSP allocated for each year:

- Their interest expense arising in that year—that is, the interest paid on its debt.
- The value of their interest-bearing liabilities giving rise to that debt—that is, the amount of debt it held.

To mirror the treatment in our regulatory models, we use the opening capital base in a given year as the total value of the NSP's assets. Then:

- To calculate the value of equity, we deduct the value of interest-bearing liabilities from the opening capital base value.
- We can work out an implied gearing level as interest-bearing liabilities divided by opening capital base value. This ratio does not directly affect our calculations. However, it is useful for analysis.

**Why and how we adjust for goodwill**

RoRE measures returns on the equity portion of the capital base; a portion we calculate as a residual – the capital base less interest-bearing liabilities. If an NSP's interest-bearing liabilities increase only to fund a premium paid above the capital base during a transaction (which we refer to as goodwill), our calculations will understate the equity invested in the NSP. This is because, in practice, goodwill will be funded from both debt and equity. If we do not apply an adjustment, we will effectively be treating goodwill as purely equity-funded and will thus artificially increase the debt proportion of the capital base.

To adjust for the impact of goodwill, we divide interest-bearing liabilities in the regulatory year following a transaction by the RAB multiple resulting from that transaction. This then estimates the debt attributable to reference services, which the NSP provides using its capital base.

For example, if an NSP is acquired at a premium above the capital base of 1.1 and holds $1 billion debt in the regulatory year after that transaction, we would scale that NSP's interest-bearing liabilities by $1 billion ÷1.1 = $909.1 million– that is, we would remove a premium of $90.9 million for goodwill.

This results in adjustments to interest-bearing liabilities held by:

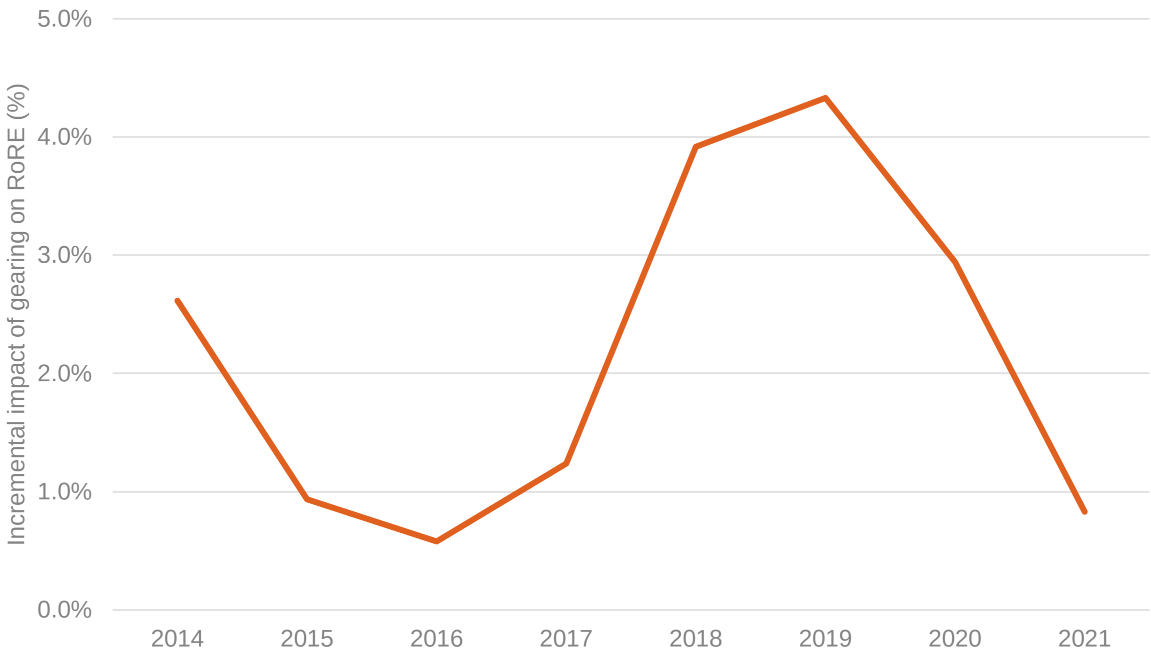
- AGN (SA) and AGN (Victoria and Albury) after the sale of Envestra to Cheung Kong Group (CKI) in September 2014 at a premium above the capital base of 1.54.
- Multinet Gas after the sale of DUET Group to CKI in June 2017 at a premium above the capital base of 1.67.

We have applied a similar approach to adjust for goodwill in our electricity network performance reporting. For example, we applied this approach to Ausgrid, except we also pre-adjusted the asset base premium to remove the assets that Ausgrid's uses to provide alternative control services (these are material for Ausgrid as they include its public lighting and metering assets).

Figure 6-12 shows how financing structure would have affected our RoRE estimates if we did not adjust for the goodwill premium (we explain the rationale for applying this adjustment in the box above). Without this adjustment, financing structure had a particularly large and lumpy impact on the estimated RoRE.

It is interesting to note that before adjusting for the goodwill premium, NSP reported debt levels were still roughly consistent with our benchmark on average. However, this average was heavily influenced by Evoenergy Gas being fully-equity funded. Most NSPs generally had higher gearing than forecast – for example, six of the nine gas NSPs have had higher gearing than forecast since 2018. Higher than forecast gearing levels have a positive and material impact on RoRE.

**Figure 6-12 Impact of financing structure before adjusting for goodwill — NSPs**




Source: As per Figure 6-11 but before the goodwill adjustment is applied to calculate debt holdings in the financial performance data (confidential version).

## 6.6 Impact of capital expenditure

We set an NSP's return on capital allowance based on the opening capital base at the start of its access arrangement period and using forecast capex.

In practice, NSPs' actual capex often differs to what was forecast. These differences contribute to differences between forecast and actual returns because:

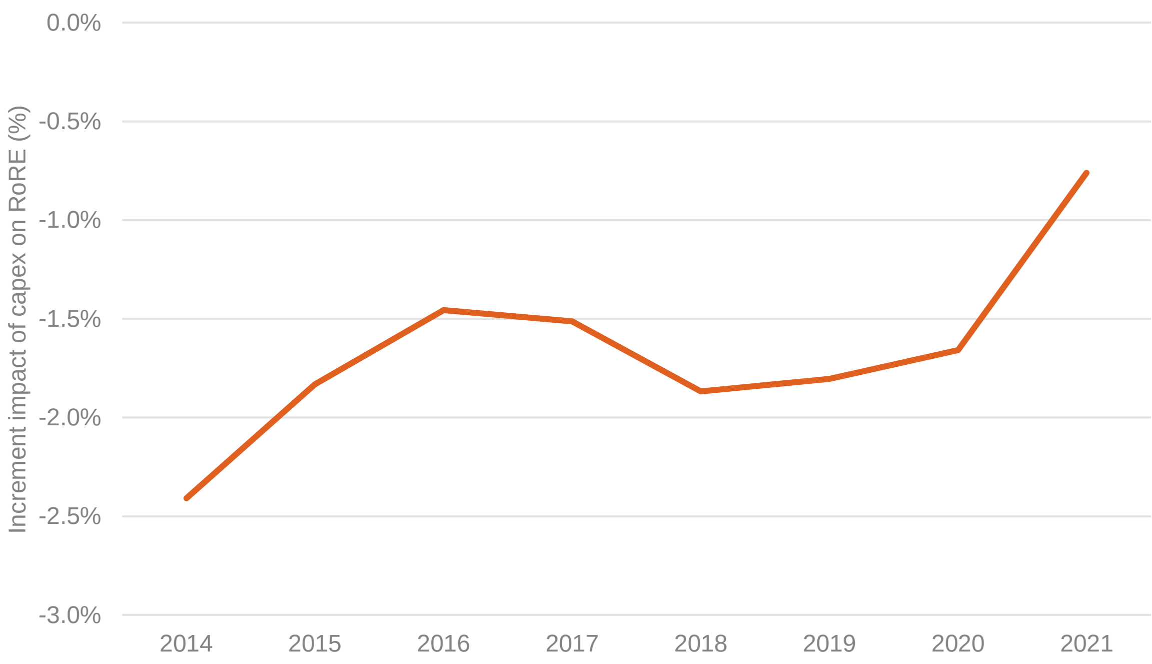
- If capex is lower (or higher) than forecast, the NSP will have to raise less (or more) capital than forecast; and

- as a result, it will keep (or lose) the incremental return on capital allowance relating to the difference until the end of the access arrangement period when the capital base is rolled-forward.

Over 2014 to 2021:

- Gas NSPs have incurred more capex than forecast on average – having a negative incremental impact on the estimated RoRE on average.
- On average, DNSPs' actual capex aligns with forecasts in 2021, although DNSPs incurred slightly less capex than forecast on average.
- On average, TNSPs actual capex was materially greater than forecasts most years, with exceptions from 2018–2020.
- This impact captures only the forecast capex incentive inherent within the framework and not any incentive scheme payments arising from previous regulatory periods.

**Figure 6-13 Impact of capital expenditure through time — NSPs**




Source: Financial performance data (confidential version). AER calculation of impact of capex through time on RoRE. Averages throughout are calculated as simple averages.

This is an important part of the implicit incentive inherent in the building block revenue framework which encourages NSPs to make efficiency gains over time.

However, NSPs keep these benefits (or penalties) whether they are caused by real efficiency gains or not. In recent years, we have undertaken extensive work on our expenditure forecasting tools and our incentive frameworks to set the best possible incentive framework to encourage network efficiency. This included introducing a capex sharing scheme (CESS) to gas DNSPs from 2018:[61] The CESS is designed to complement this inherent incentive so that the incentives are even throughout a regulatory period. We analyse the impact of incentive schemes on network returns in section 6.8.

## 6.7 Impact of operating expenditure

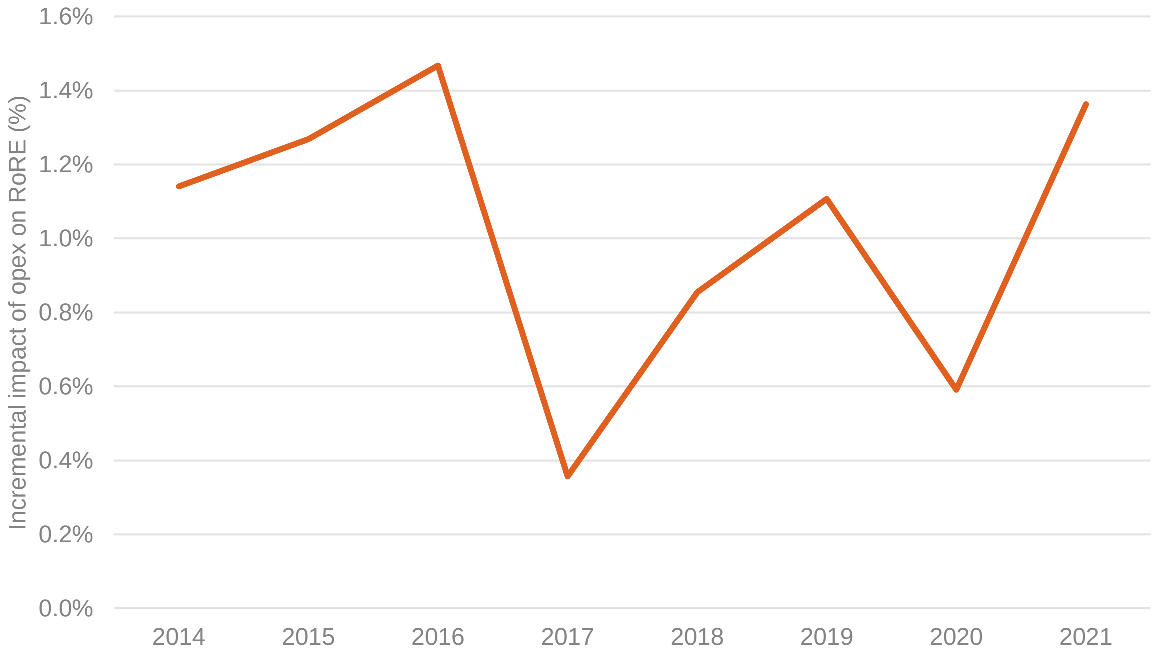
Similar to capex, NSPs commonly spend less or more opex than our forecast. Before the impacts of any opex efficiency schemes occur, NSPs keep these gains or penalties within the access arrangement period in which they occur. Through our resets, we then reflect any efficiency gains in lower forecast opex allowances, at which point the benefits of the networks' performance are shared with consumers.

Over 2014 to 2021:

- Gas NSPs incurred less opex than what we forecast on average, although not by a large amount, reflecting that the consistent and recurrent nature of opex makes it easier to forecast.
- By outperforming opex forecasts, NSPs received higher RoRE on average. This positive incremental impact varied in magnitude throughout the period, ranging from 43 to 144 basis points.

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

**Figure 6-14 Impact of operating expenditure through time — NSPs**




Source: Financial performance data (confidential version). AER calculation of impact of opex through time on RoRE. Averages throughout are calculated as simple averages.

## 6.8 Impact of tax structure and its effect on the tax rate

Unlike interest expense, we calculate tax expense at the NSP level using a 'bottom-up' approach. Specifically, we use NSPs' actual revenue and expenses to estimate actual taxable income. This entails starting with EBIT and then:[62]

- Deducting interest expense
- Adding back nominal-straight line depreciation and deducting tax asset base depreciation instead. We source tax asset base depreciation from the RFM where available
- Adjusting for customer contributions, gifted assets, adjustments to prior returns or disallowed interest expense

We then multiply taxable income by a tax rate, which varies depending on the corporate structure in which the NSP is held. Given the fully regulated gas NSPs are held under corporate structures, their applicable tax rates reflect the benchmark tax rate of 30%. As such, tax structure has no impact on their RoRE.

62 This approach reflects PwC, *AER: Profitability measures review – Advice on the allocation of interest and tax expense*, June 2019, p. 16.

Over 2014 to 2021, the tax structure had no effect on RoRE. All gas NSPs reported they were taxed as companies, so incurred tax rates equivalent to our benchmark of 30%.

Our tax review found NSPs' use of immediate expensing was a major driver of past differences between forecast and actual tax.[63] Immediate expensing allowed NSPs to apply tax depreciation at a faster rate than our models captured. In the short term, this reduced tax expense compared to our forecast tax allowance. However, for a given asset value there is a fixed level of depreciation and tax depreciation NSPs can apply over the lives of the asset. This means that the increased tax depreciation in the past will be offset by reduced tax depreciation in the future.

PwC's advice is that since tax adjustments relating to immediate expensing are timing in nature rather than permanent, they should not impact tax expense for the purpose of profitability reporting. PwC observed that while our approach to making tax expense adjustments may wrongfully include temporary affects, timing differences have not materially affected RoRE estimates to date.[64]

Following the tax review, we updated our PTRM and RFM to incorporate immediate expensing of tax depreciation. If it occurs in the future, our profitability measures should reflect this through the TAB (tax asset base) depreciation and its impact on our estimate of actual tax arising from reference services. PwC observed that these changes following the tax review will likely lead to temporary effects becoming more material in our RoRE estimates in future years and flagged this as a risk.[65] We will likely need to monitor and potentially adjust for these effects in future network performance reports.

## 6.9 Impact of incentive schemes

In addition to the inherent incentives within the regulatory framework, it also includes targeted incentive schemes. These schemes are important regulatory tools designed to encourage desirable behaviours by NSPs (namely to improve efficiency and reliability), which in turn will deliver better outcomes for consumers and promote achievement of the National Gas Objective.

63 AER, *Tax Review 2018—Final report, December 2018*, p. 64.

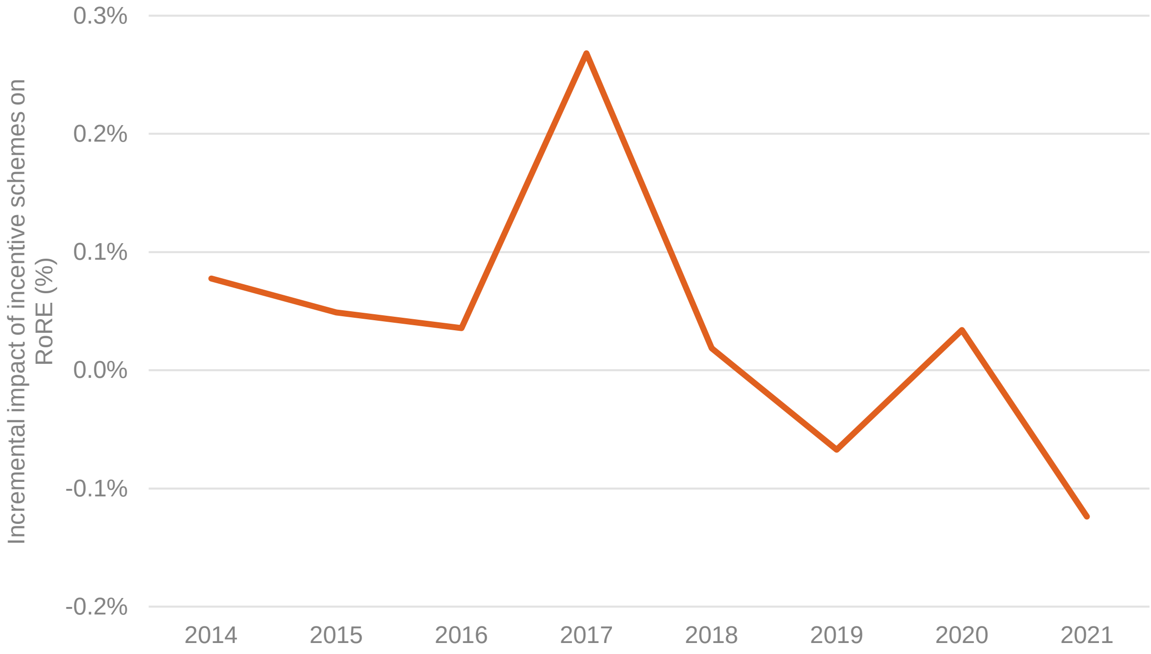
64 PwC, *Appendix A – High level publishable summary: Review of gas NSPs' responses to the AER's profitability measures information request*, 30 June 2022, pp. 2, 4.

65 PwC, *Appendix A – High level publishable summary: Review of gas NSPs' responses to the AER's profitability measures information request*, 30 June 2022, p. 4.

Over 2014–21 we find that:

- Incentive schemes had a minimal impact on the RoRE. This reflects that most incentive schemes apply exclusively to electricity networks and no incentive schemes apply to gas TNSPs.
- We expect that impact is likely to grow in the coming years as we continue to apply the new CESS to gas DNSPs (we only started to roll this scheme out to gas DNSPs in 2018).

### Figure 6-15 Impact of incentive schemes through time — NSPs




Source: Financial performance data (confidential version). AER calculation of the difference between RoRE with and without incentive scheme payments. Averages throughout are calculated as simple averages.

# 7 Focus area: Impact of COVID-19 on demand and network revenue

To reduce the spread of the COVID-19 virus in March and April 2020, state[66] and federal[67] governments introduced several lockdown restrictions. This led to schools, workplaces and businesses closing and widespread changes to Australians' day-to-day activities. These changing activities influenced the energy needs and consumption patterns of residential, commercial and industrial consumers.

For most of Australia, June and July 2020 ushered in a period where restrictions were loosened, and businesses and schools reopened. However, in Victoria, a second wave of the COVID-19 virus led to the state reintroducing lockdown measures,[68] with greater restrictions imposed in Melbourne to curtail the spread of the virus.[69] The lockdown measures lasted for 111 days in Victoria between 8 July 2020 and 27 October 2020, after which Victoria gradually began to loosen restrictions to come in line with the rest of Australia. In 2021, different Australian states endured further waves of COVID-19 outbreaks, which prompted state governments to impose further lockdowns. The most significant lockdown restrictions imposed included another 78-day lockdown in Victoria/Melbourne and 107 days of restrictions in Sydney, both occurring in the second half of 2021.

In this section, we set out our analysis of the impact arising from the COVID-19 pandemic on the gas NSPs and their consumers. We have focussed on:

- How COVID-19 affected the consumption of residential, commercial and industrial consumers
- As a result, how COVID-19 affected gas NSPs' revenue collection.

We have mostly focussed our analysis on Victorian DNSPs because:

- the first and second wave of COVID-19 lockdowns and resulting effects were longest lasting in Victoria, including additional restrictions running throughout 2021
- because of the above, we would expect any material impacts on DNSPs due to COVID-19 would appear most clearly in Victorian consumption data through 2020-21 compared to pre COVID-19 years[70]
- residential gas consumption has a particularly large role in Victoria.

66 New South Wales Government, *New COVID-19 restrictions begin as schools move towards online learning*, 23 March 2020; Queensland Government, *Business closures and restrictions*, 23 March 2020; South Australian Government, *Service SA changes to stop the spread*, 27 March 2020; Tasmanian Government, *Keeping Tasmanians safe and secure*, 1 April 2020; Victorian Government, *Statement from the Premier*, 30 March 2020; Western Australian Government, *Important new COVID-19 measures come into effect*, 23 March 2020.

67 Department of Prime Minister and Cabinet, *National Cabinet Statement – Media Statement*, 29 March 2020.

68 Department of Premier and Cabinet, *Statement from the Premier*, 7 July 2020.

69 Department of Premier and Cabinet, *Statement on Changes to Melbourne's restrictions*, 2 August 2020.

70 This data for each DNSP is in the Gas DNSP – Operational Performance Data, published alongside this report.

Our key findings are that:

- Overall, the COVID-19 response appears to have had a limited aggregate impact on gas consumption and DNSP revenue and expenditure.
- Over 2020 and 2021 in Victoria, we observed a small shift from commercial and industrial consumption to residential consumption.
- It is unclear that the annual increase in residential consumption was driven by COVID-19 restrictions. The annual increase is more likely due to weather effects.
- The decrease in commercial consumption largely coincides in the months when Victoria experienced lockdown restrictions.

While most of the consumption shifting between customer classes in Victoria had a limited overall impact on consumption and revenue, it did affect the relative amount that each customer class spent on reference services.

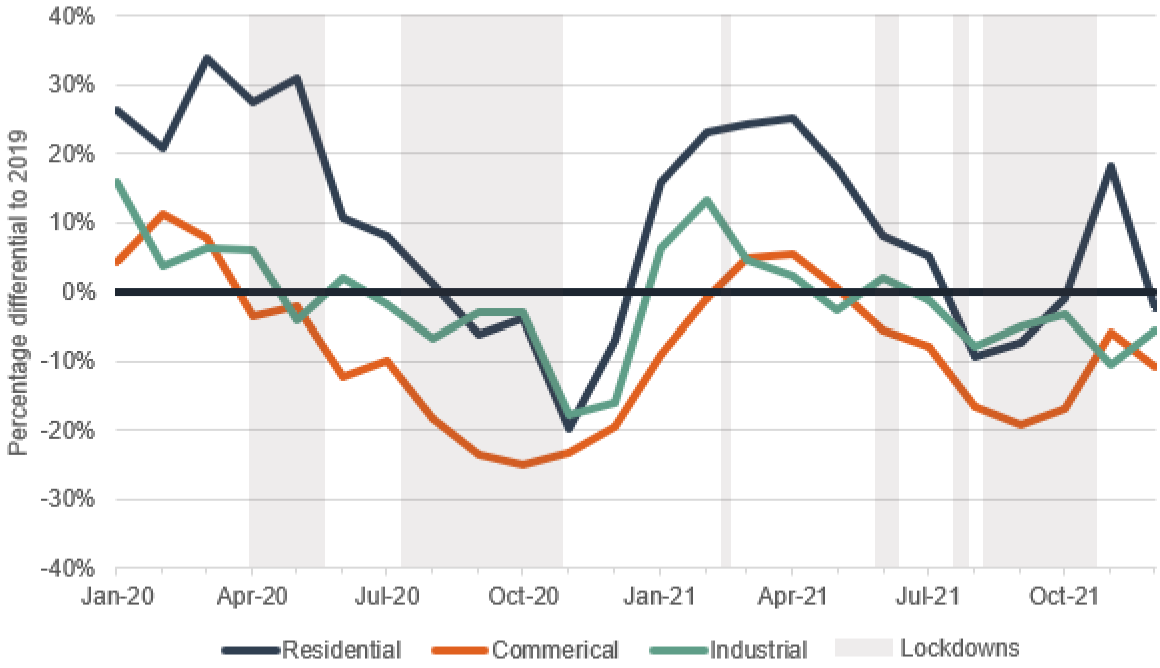
Importantly, while lockdown restrictions are unlikely to return, we recognise that the impacts of COVID-19 are ongoing, and the way many people work and live has changed as a result. We will continue to monitor these effects as necessary in coming years. In the remainder of this section, our analysis focusses on impacts of the COVID-19 pandemic on network revenue collection over regulatory years 2020 and 2021.

## 7.1 Impacts of COVID-19 on Victorian gas consumption

To explore the impact of COVID-19 on network consumers, we have focussed in particular on observable changes in consumption patterns.

To illustrate the impact of COVID-19 on gas consumption patterns, Figure 7-1 shows the Victorian monthly percentage change in total gas consumption by consumer type across 2020 and 2021.

**Figure 7-1 Victorian monthly total gas consumption change relative to 2019**




Source: Information request from Victorian DNSPs for monthly energy report, AER calculation of monthly sum of consumption by consumer type in 2020 and 2021 divided by monthly sum of consumption by consumer type in 2019.

Figure 7-1 illustrates that:

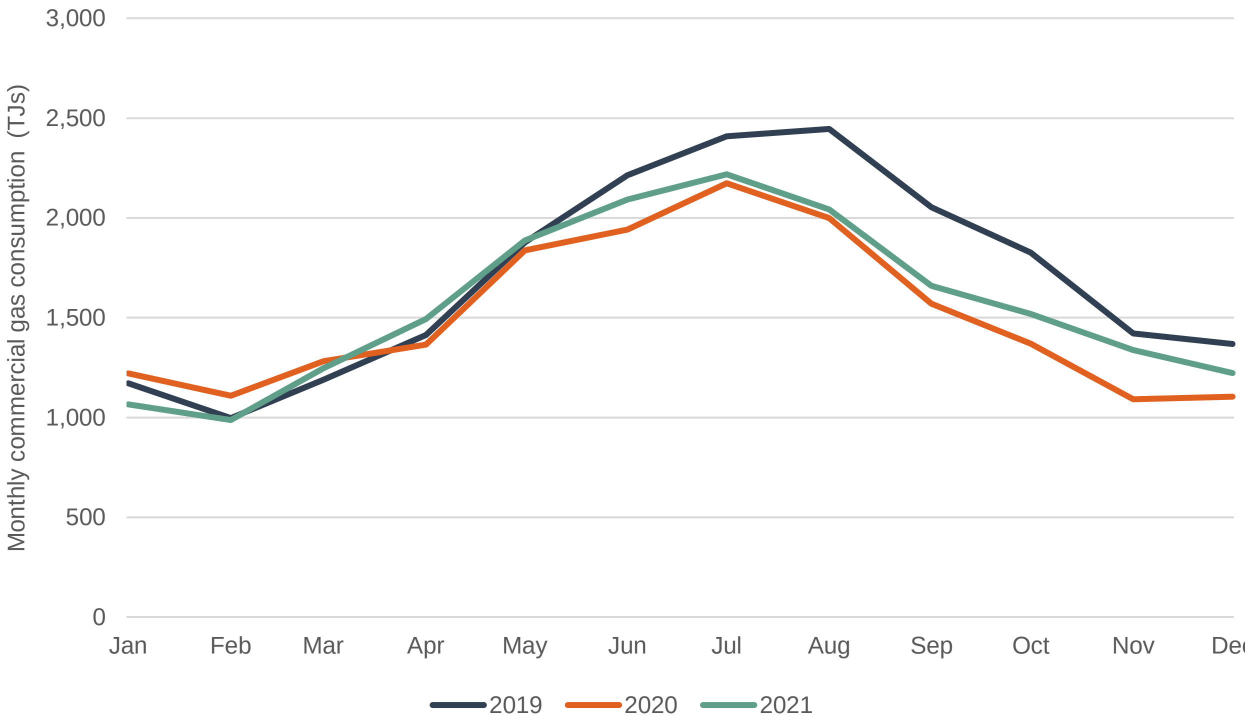
- Up to the lockdowns in March 2020, consumption for all consumer types was higher than in 2019 with residential consumption up to 30% higher. Variation from 2019 consumption for this period was likely driven by the weather.
- At the introduction of lockdowns in March 2020, residential consumption remained at a high level relative to 2019, while commercial and industrial consumer consumption began to decline to within 10% of 2019 levels.
- As 2020 progressed, all consumer types used less gas than in 2019. This period included the second lockdown, which seemed to have had the largest impact on commercial business. When stage 4 restrictions were introduced at the start of August 2020, commercial consumption fell 20–25% relative to 2019.[71]
- Once the lockdowns ended in November 2020, consumption by all consumer types began to return towards 2019 levels.
- Consumption for all consumer types in 2021 generally followed a similar pattern to 2020, varying by less than 10% of 2020 levels. The one exception to this was in November 2021 where residential consumption peaked to almost 20% above 2019 levels, which coincided with Victoria finishing its sixth and last lockdown at the end of October, as well as colder weather (see Section 7.2).

71 Victoria State Government – Health and Human Services, *Premier's statement on changes to Melbourne's restrictions*, 2 August 2020 .

While there appears to be consistent trends between consumption changes and lockdowns for each consumer type, it is unclear that COVID-19 lockdowns caused residential consumption to materially change relative to 2019 levels. Rather, differences in residential consumption between the 2020 and 2021 years, and 2019 are more likely due to other factors such as the weather (see Section 7.2), or growth in customer numbers.

However, COVID-19 lockdowns appear to have affected commercial consumption. Figure 7-2 illustrates that for the first half of both 2020 and 2021, Victorian commerical monthly consumption was similar to 2019. However, in the second half of both years, commercial consumption was materially lower than in 2019, which is when the state was most restricted due to lockdown measures.

**Figure 7-2 Victorian monthly commercial gas consumption over 2019, 2020, and 2021**



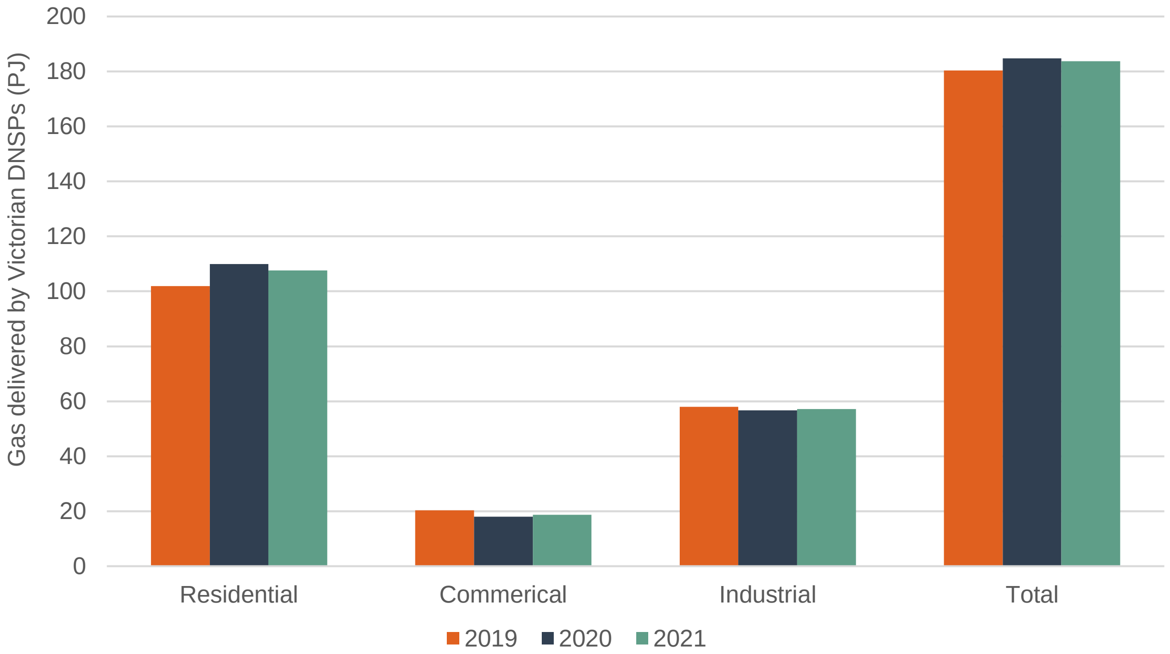

Source: Information request from Victorian DNSPs for monthly consumption report, AER calculation of sum of monthly usage by Victorian commercial consumers.

Industrial consumption followed a similar pattern to commercial consumption, but the magnitude of the change was smaller. COVID-19 lockdowns therefore possibly also affected industral usage, although to a lesser extent.

Reduced commercial and industrial gas usage due to COVID-19 seems reasonable given business activity declined or stopped for large portions of both 2020 and 2021.

When considering annual gas consumption, the higher residential gas usage in the early months of 2020 and 2021 more than offset any reduction in commerical and industrial usage. As such, total gas usage was slightly higher in 2020 and 2021 than it was in 2019, as shown in Figure 7-3.

**Figure 7-3 Annual Victorian gas consumption by consumer type (2019–2021)**




Source: Information request from Victorian DNSPs for monthly energy report, AER calculation of sum of annual gas usage by consumer type in 2019, 2020, and 2021.

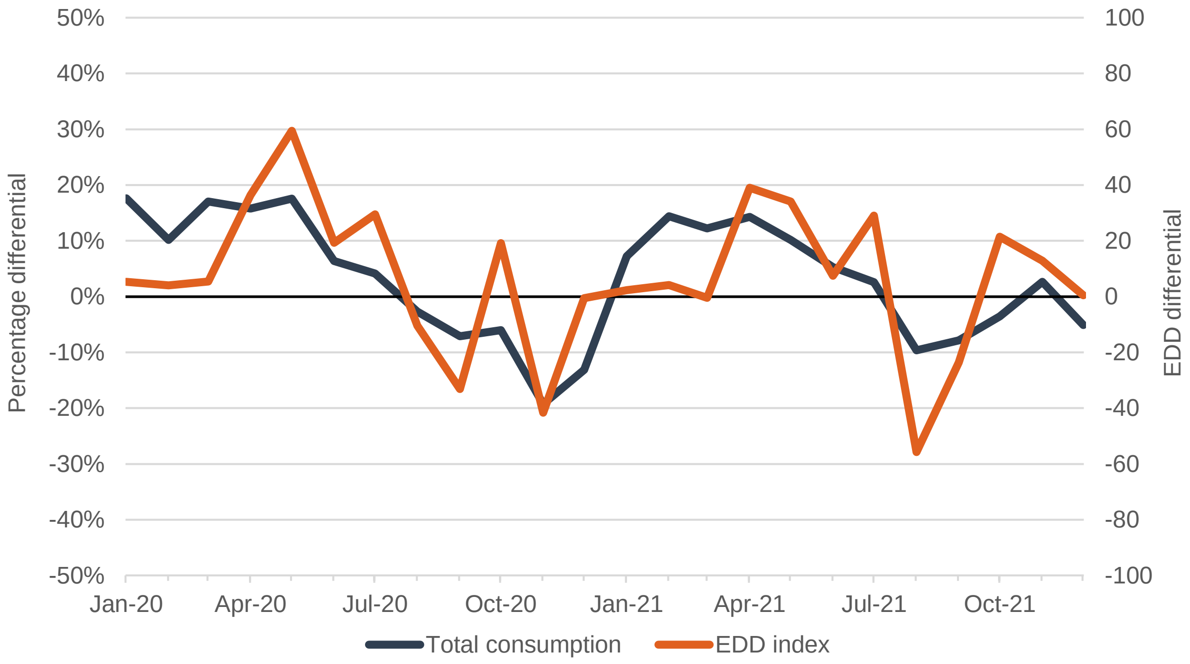
While there were slight shifts in consumption by all consumer types over 2020 and 2021 relative to 2019, total consumption did not change much. As such, DNSPs were relatively unaffected in their ability to deliver gas and gather revenue due to any consumption changes caused by COVID-19.

## 7.2 Impacts of temperature on consumption

Aside from the slight shift in consumption from business to residential consumers, there remains monthly variation in 2020 and 2021 consumption compared to 2019. In our view, this largely reflects the sensitivity of gas consumption to the weather. Figure 7-4 illustrates this relationship by comparing the monthly change in total Victorian consumption against the monthly difference in weather, as measured by average effective degree days (EDDs)[72] in 2020 and 2021 compared to 2019.

72 EDD has been used extensively in the Victorian gas industry since its development in the 1970s. The EDD approach takes measurable weather factors into consideration (wind velocity, sunshine and seasonal variations in heating propensity) in addition to temperature to adjust demand for weather fluctuations.

**Figure 7-4 Victorian monthly change in gas consumption and EDDs relative to 2019**




Source: Information request from Victorian DNSPs for monthly energy report, AER calculation of monthly sum of total consumption in 2020 and 2021 divided by monthly sum of consumption by consumer type in 2019 compared with average EDD differential across Victoria through 2020 and 2021 relative to 2019.

There is a clear positive correlation between changes in gas demand and changes in the EDD index. This is as expected as higher EDDs are designed to reflect higher demand days and are associated with colder temperatures.

When comparing 2020 against 2019:

- The EDD index and gas consumption were both higher in the first half of 2020 than in 2019.
- During the second half of 2020 (other than October), the EDD index was lower than in 2019. Gas consumption was also lower in the second half of 2020.

When comparing 2021 against 2019:

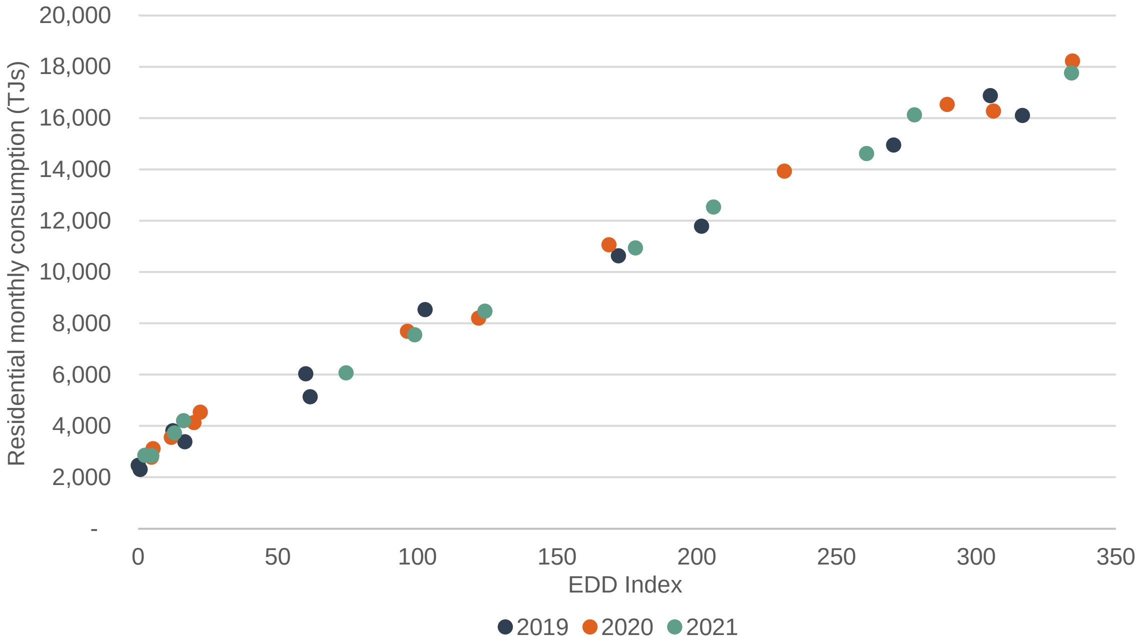
- The EDD index was only lower in August 2021, when gas consumption also declined.
- The EDD index was higher in November 2021, when residential gas consumption spiked. This was mentioned in Section 7.1 as it coincided with loosening restrictions in Victoria. This is important as it indicates that the increase in residential consumption in November 2021 may have been driven by cooler weather rather than the loosening of restrictions.

## 7.3 Weather effect on different consumer types

While total consumption appears affected by the weather (as shown in Figure 7-4), residential consumption is by far the largest component of total consumption. Therefore, we have examined if the impact of weather differs between consumer types.

Figure 7-5 shows the relationship between residential monthly gas usage and weather effects (as measured by EDDs).

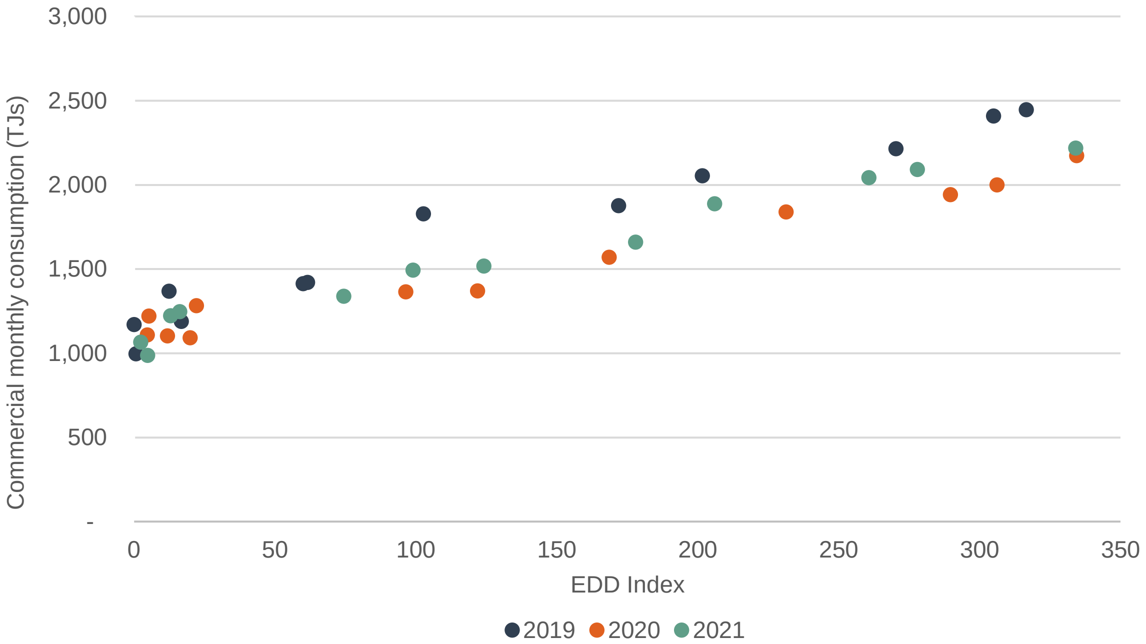
**Figure 7-5 Victorian residential monthly gas usage against EDDs**




Source: Information request from Victorian DNSPs for monthly energy reports, AER analysis of monthly residential consumption relative to EDD.

Residential consumption is highly positively correlated with EDDs, with the relationship similar across all three years. This indicates that weather strongly affects the overall level of residential gas usage in each month and year.

**Figure 7-6 Victorian commercial monthly gas usage against EDDs**

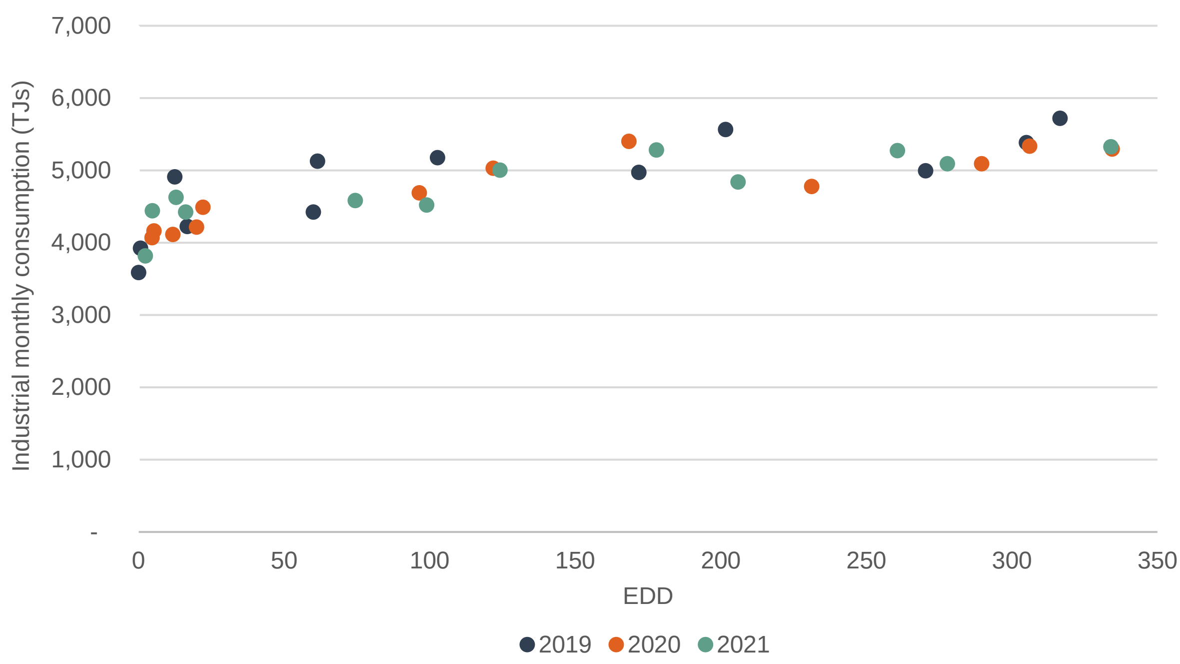



Information request from Victorian DNSPs for monthly energy report, AER analysis of monthly commercial consumption relative to EDD data.

Figure 7-6 shows that the relationship between commercial monthly gas usage and weather effects (measured by EDD) is not as strong as it is for residential gas usage.

A noteworthy observation from Figure 7-6 is that for an equivalent EDD month in 2020 and 2021, when compared with 2019, commercial gas usage was lower. This indicates that a driver other than weather effects caused lower gas usage in 2020 and 2021. Given that declines in commercial gas usage in 2020 and 2021 relative to 2019 mostly occurred when Victoria was experiencing lockdown restrictions, it is likely that COVID-19 restrictions had some effect on commercial usage.

**Figure 7-7 Victorian industrial monthly gas usage against EDDs**




Source: Information request from Victorian DNSPs for monthly energy report, AER analysis of monthly industrial consumption relative to EDD data.

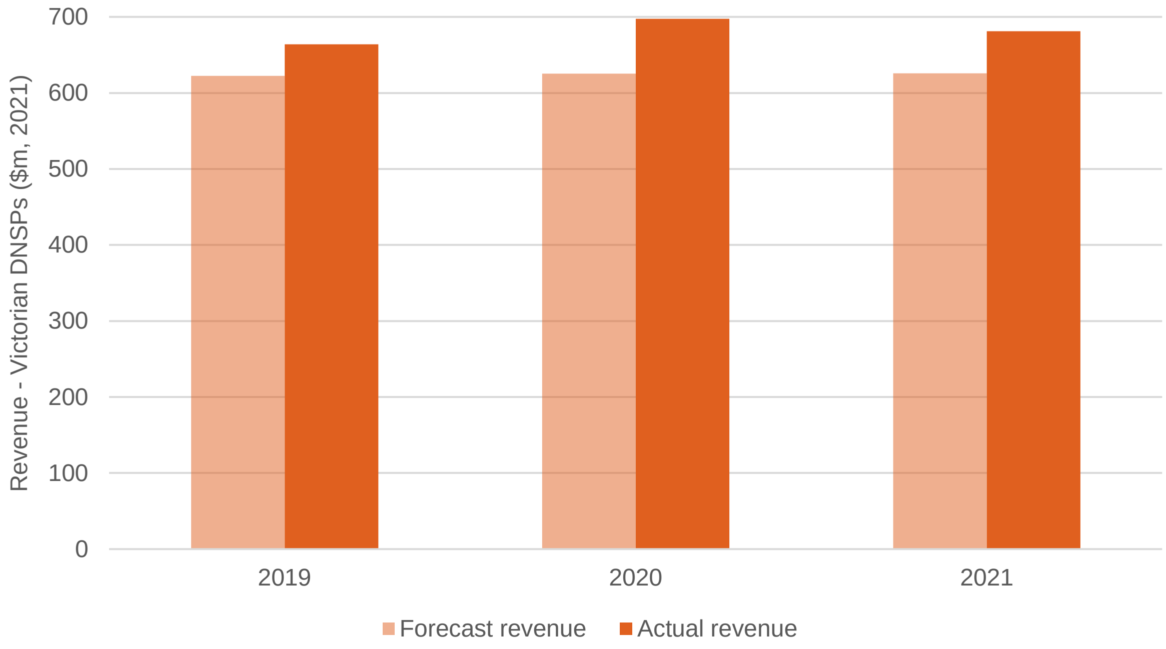
Figure 7-7 shows the relationship between industrial monthly usage and weather effects (as measured by EDDs) was weaker than what it was for residential and commercial gas usage. High EDD months corresponded with somewhat higher gas usage relative to low EDD months, with this effect consistent between 2019, 2020, and 2021. This is unsurprising as most industrial gas usage would not be highly affected by the changing weather, but rather by commercial decisions.

## 7.4 COVID-19 lockdown restrictions and DNSP revenue

Overall, lower commercial and slightly lower industrial consumption in 2020 and 2021 relative to 2019 was negated by higher residential consumption, as shown previously in Figure 7-3.

As there was minimal impact on overall consumption, no Victorian DNSP had issues recovering revenue in 2020 or 2021, as shown in Figure 7-8. Rather, revenue recovery for each Victorian DNSP was consistent with pre COVID-19 trends.[73]

**Figure 7-8 Victorian DNSP revenue recovery relative to forecast over 2019, 2020, and 2021**

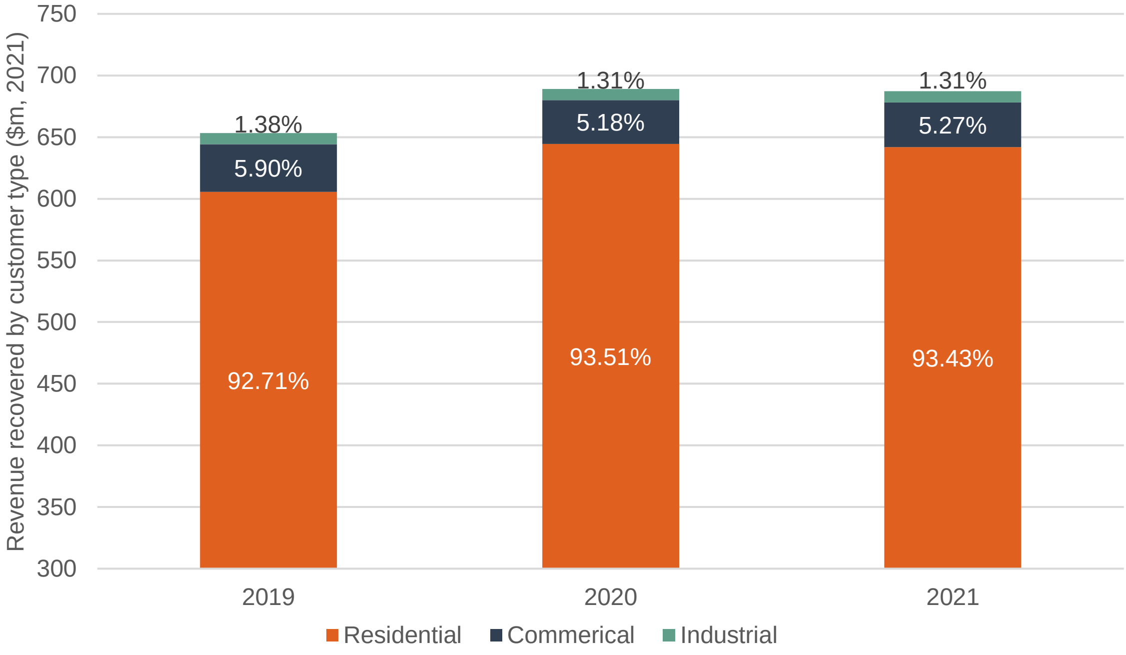



Source: Operational performance data – Distribution. Original sources: Annual RINs – F3.1 Reference services (reference services revenue) and PTRMs – Revenue summary – Building block components (forecast revenue). AER calculation to convert into $2021 terms.

While Victorian DNSPs saw minimal revenue impacts, Figure 7-9 shows they recovered a greater proportion of their revenue from residential consumers in 2020 and 2021 relative to 2019.

73 Further details can be found in our operational performance data model, published alongside this report.

**Figure 7-9 Victorian DNSP revenue recovery by consumer type in 2019, 2020 and 2021**




Source: Information request from Victorian DNSPs for monthly energy report, AER analysis of share of revenue recovery from each customer type across 2019, 2020, and 2021.

Figure 7-9 illustrates:

- the percentage of the total revenue recovered from residential consumers increased in 2020 and 2021 compared with 2019, with total revenue recovered from residential consumers increasing by 6%.
- the percentage of the total revenue recovered from commerical consumers decreased in 2020 and 2021 compared with 2019, with total revenue recovered from commercial consumers decreasing by 7–8%.
- the percentage of the total revenue recovered from industrial consumers remained relatively constant in 2020 and 2021 compared with 2019, with total revenue recovered from industrial consumers decreasing by 0.07%.

While there were consumption pattern changes in 2020 and 2021, there were no material differences in the overall level of gas delivered and revenue collected by Victorian DNSPs compared with previous years. In our view, this reiterates the ability of gas NSPs providing an essential service and operating under a stable regulatory regime to withstand this type of economic shock.

Residential consumers used more gas in 2020 and 2021 (which was most likely not driven by COVID-19 lockdown restrictions), meaning the amount of revenue recovered from residential customers increased relative to 2019. Commericial, and to a lesser extent, industrial consumers saw their gas usage decrease in conjunction with lockdown restrictions. However, there are many drivers of gas usage and absolute causation is unclear.

# 8 Focus area: Changes in asset age profiles

The capital base is the stock of assets used to provide reference services– it represents the real monetary value of investments in the network. The capital base is an important input in determining NSPs' revenue and prices paid by consumers through the return on capital and regulatory depreciation building blocks.

Understanding the composition of assets in the asset base helps us to estimate when asset replacement will likely be needed to maintain existing services. In this section, we report on NSPs':

- capital base value and composition
- weighted average remaining life (WARL)
- capex profile based on available data since 2011
- replacement capex and replacement rates.

Our information paper on 'Regulating gas pipelines under uncertainty'[74] identified several headwinds facing natural gas demand including:

- decarbonisation policies
- the relative pricing of substitute energy services
- energy efficiency improvements
- gas demand for electricity generation (transitional)
- consumer sentiment (this is a combination of above factors, including individual taste)

Recent NSPs' regulatory proposals have included strategies to address these factors through their future capex programs, options to capital recovery, and intertemporal price paths.[75] As we decide which aspects of these proposals to approve, it is becoming increasingly important that we understand these dynamics. Ongoing monitoring will increase the information base on which we and stakeholders can form considered views. In last year's report, we identified that the risk of asset stranding exists in the longer term due in part to Government policies to decarbonise the economy. Asset stranding applies to both the regulated gas networks and gas users, such as residential customers with gas appliances.

Given the long life of the gas networks, policies aimed to disincentivise growth in gas demand have the potential to reduce the capacity of NSPs to recover existing capital investments. If demand declines such that the network costs are spread across less customers or over smaller volumes, the unit cost of transporting gas is likely to increase, all else being equal.

74 AER, *Regulating gas pipelines under uncertainty*, November 2021.

75 Multinet Gas Networks, *Five year plan for our Victorian distribution network*, July 2022, pp. 55–69; AusNet, *Access arrangement information: Gas access arrangement review 202–28*, July 2022, pp. 21–39; AGN, *Five year plan for our Victoria and Albury distribution networks*, July 2022, pp. 54–63.

Asset age profiling is important to identify the likely size of the capital base investment to be recovered from users and future efficient expenditure levels to maintain the safe operation of the network.

Our key findings are that:

- In 2021, DNSPs' WARLs were between 31 and 46 years. JGN and Evoenergy Gas had the longest remaining lives, due to high and medium pressure mains and services having the longest standard asset lives of 80 and 50 years respectively. This exacerbates the effect of having undertaken replacement capex programs earlier than other DNSPs.
- In 2021, TNSPs' WARLs were between 27 and 50 years. This higher level of variability was driven by greater differences in when the transmission pipelines were originally constructed.
- Pipelines, mains and services were major drivers of NSPs' capex. The timing of replacement capex has a significant influence on asset age.
- Distribution mains replacement rates between 2012 to 2021 were:
- lowest for Evoenergy Gas and JGN at 0.04% and 0.03% on average per annum
- highest for the Victorian and SA DNSPs in the range of 1.48% for AusNet and 4.31% for AGN (SA) on average per annum.
- Based on current modelling assumptions, including standard asset life and depreciation approach, the current stock of assets (as at 2021) will fully depreciate between 50 to 80 years.

## 8.1 The capital base

WARLs demonstrate how the existing stock of assets (by monetary value) changes over time based on approved capex and depreciation rates.[76] We modelled NSPs' WARLs using their approved capital base, capex, and asset lives by asset class using the written-down monetary values contained in the relevant RFMs.[77]

We applied the WARL as a proxy to measure asset age. Since WARL calculations are based on the written down value of assets, they place more weight on the remaining lives of higher value assets. This can be less accurate for estimating asset age relative to measures that use data based on when assets were installed. Despite these limitations, the WARL provides a reasonable proxy on which to compare networks.

76 We note as a measure of asset age, the WARL presents a second-best approach in the absence of detailed data on asset quantities installed. WARL (weighted by value) as a metric is limited because it may not provide an accurate reflection of the underlying age profile of assets to better identify replacement required.

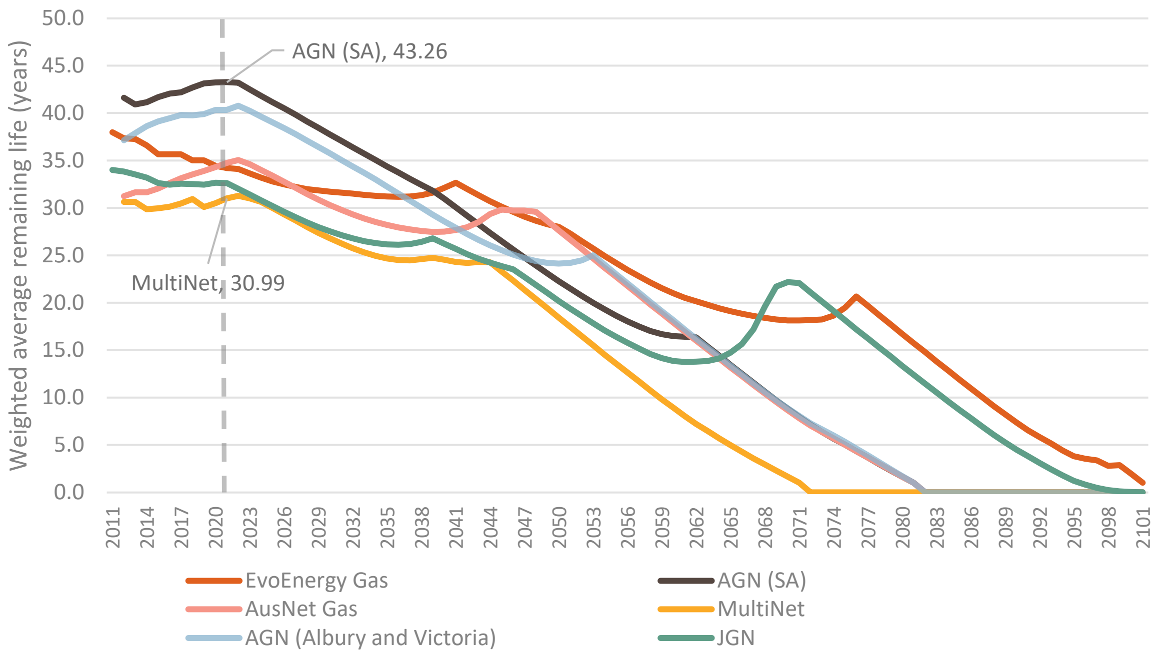
77 Data is sourced from the approved capital base RFMs available on the AER website.

### 8.1.1 Distribution capital bases and weighted average remaining lives

Figure 8-1 shows how the average age of DNSPs' *existing* asset stock (weighted by monetary value) has and is expected to change over time, adjusted for depreciation and capex. This analysis demonstrates the long-lived nature of gas infrastructure assets. However, it is not a forecast of gas NSPs' future WARLs as the model does not include new capex past 2021 due to limitations in data availability. If we were to forecast future WARLs, some assumption around new capex would be required as some replacement capex would be required to maintain a functioning and safe network.

In 2021, the average WARL of gas DNSPs was 36 years inclusive of actual capex incurred in 2021. AGN (SA) had the longest expected remaining life of 43 years and Multinet Gas had the shortest of 31 years. WARLs for all DNSPs increased up to 2021, except for Evoenergy Gas and JGN. This reflected the timing of capex programs.

**Figure 8-1 Capital base weighted average remaining life (years) – DNSPs**




Source: AER approved RFMs, PTRMs and annual RIN data 2010 to 2021.

Note: We collated data from each DNSP's approved determination RFMs and PTRMs on the opening capital base value and depreciation by asset class since the AER commenced regulation. We used this data to calculate WARL each year.

The size and composition of capex programs affects the value-weighted average remaining economic life of the capital base (measured by the WARL) over which DNSPs provide services. DNSPs with a high proportion of connections or mains replacement capex have longer WARLs.

WARL estimates in Figure 8-1 are heavily weighted towards the original capital base values around 2010-11. The original capital base values represent the historical written down value of the capital stock, or existing assets, up to that point in time – before which, we did not have detailed data on the timing and breakdown of capex. The average age of the opening capital bases of DNSPs was 35 years. This would indicate that the opening capital base value composition is weighted in favour of newer assets with higher written down values relative to the lower written down values of older assets. This is supported by higher degrees of replacement capex over recent decades.

Our WARL estimates display points of inflection. As we have not modelled future replacement capex, these points demonstrate the effect of the how the higher valued (weighted) assets dominate the WARL calculation. The WARL decreases to the point where the original opening capital base values fully depreciate. At that point, there is a notable uptick in the estimated WARL, before it resumes a gradual decline. This demonstrates the effect of lumpy capital investment combined with the assumption of no replacement, which would otherwise result in a smoother depreciation profile.

We also calculated the total capital base age as the difference between the standard asset life (age at construction) less the remaining life, weighted by the value of the assets in each year. This calculation shows that, based on the opening capital base values in 2012:

- AGN (SA) had the youngest average asset age of 10.5 years
- AusNet was the oldest network with an average asset age of 24 years.

These outcomes differ from our WARL calculations due to differences in DNSPs' asset classifications and historically approved standard asset lives. Due to differences in approved original standard asset lives (expected life at commissioning), two assets may have the same remaining life, but one may have a higher age. Several factors can cause differences in standard asset lives, including when the network was constructed, its configuration and operating environment.

In section 8.2, we look at capital base composition, including asset classification and range of standard asset lives.

**Depreciation schedules and asset lives**

A gas DNSP's depreciation schedule sets out how its capital base is to be depreciated for the purposes of determining a reference tariff.[78]

Key inputs into the depreciation schedule are the economic life of assets or a group of assets (known as an asset class). Our assessments of the standard (economic) life and remaining asset lives comply with the depreciation criteria in the National Gas Rules. This assessment also considers the revenue and pricing principles and seeks to promote the National Gas Objective.[79]

In general, consistent standard asset lives for each asset class should support reference tariffs to vary in a manner that promotes efficient investment in reference services. Our assessment of

78 National Gas Rules, r.88.

79 National Gas Law, s 28; National Gas Rules, r.100(1).

an asset class's standard asset life also considers the technical life (or the engineering designed life) of the assets within the asset class. The economic life need not match the technical life of the asset, but if an asset is technically available for use, then it usually is able to serve an economic purpose.

In 2021, we accepted Evoenergy Gas's proposal to apply a shorter standard asset life to pipeline assets in both the ACT and NSW regions.[80] Standard asset lives for its high-pressure mains reduced from 80 to 50 years and standard asset lives for its medium pressure mains and services reduced from 50 to 30 years.[81]

In its proposal, Evoenergy Gas cited ACT Government's Climate Change Strategy 2019–25 to reduce emissions from transport and gas after 2020.[82] The strategy included the:

- Removal of a mandated requirement that new suburbs be connected to gas
- Support of gas to electric appliance upgrades
- Encouraging all new (housing) builds to be all-electric.

We accepted Evoenergy Gas's proposal to reduce the standard asset life of pipeline assets in the ACT and NSW regions, because the ACT Government's policy for existing gas consumers to progressively switch over to electricity could lead to a decline in the future usage of Evoenergy Gas's network.[83]

The changes to the standard life of the pipeline assets and depreciation schedule will apply from the start of the 2022 regulatory year. Therefore, they are not reflected in Evoenergy Gas's WARL in Figure 8-1.

### 8.1.2 TNSP capital bases and weighted average remaining lives

In 2021, of the TNSPs, RBP had the longest expected WARL of 50 years. VTS had the shortest WARL of 27 years. From 2011 to 2021, WARLs for VTS and Amadeus varied materially. This variability reflects the lumpiness of capex projects, reported on an 'as-commissioned' basis, to expand pipeline capacity.

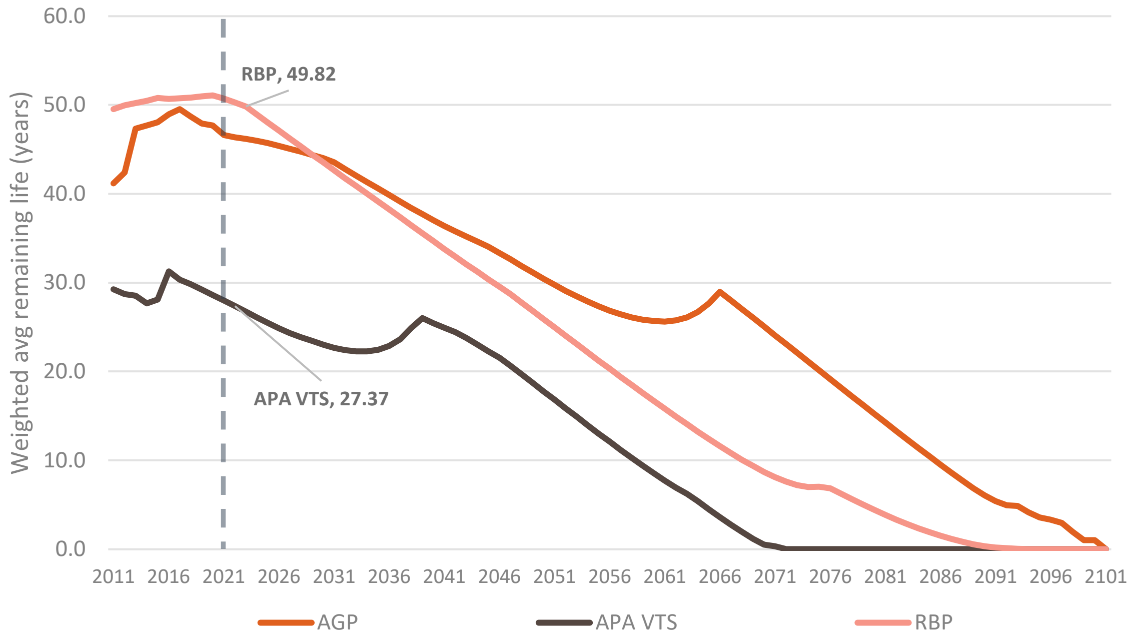
80 AER, *Final decision – Evoenergy Gas access arrangement 2021 to 2026, Attachment 4 – Regulatory depreciation*, 2021, pp. 11-12.

81 Evoenergy Gas, *Regulatory proposal – Attachment 4 – Capital base and depreciation*, June 2020, pp. 4-10.

82 Evoenergy Gas, *Overview: Access arrangement information – ACT and Queanbeyan-Palerang gas network 2021–2026*, June 2020, pp. 7-9.

83 AER, *Final decision – Evoenergy Gas access arrangement 2021 to 2026, Attachment 4 – Regulatory depreciation*, 2021, pp. 5-6.

**Figure 8-2 Capital base weighted average remaining life (years) –TNSPs**




Source: AER approved RFMs, PTRMs, and annual RINs 2010 to 2021.

As discussed in Section 8.1.1, the opening capital base at the start of the period affects the WARL profile. This effect is more staggered for TNSPs than what we observe for DNSPs – with notable upticks ranging from between 2035 (VTS) and 2080 (RBP). Figure 8-2 shows that Amadeus and RBP are expected to depreciate the existing stock of assets over the next 80 and 74 years respectively. In contrast, VTS is expected to fully depreciate its existing assets in 51 years, by 2071. Based on current assumptions, future capex programs will extend the WARLs shown in Figure 8-2.

Carbon reduction policies indicate potential future scenarios where gas demand may decline and prices may rise, creating a potential for gas network assets to become stranded.[84] This gives cause for NSPs to maintain rather than expand their current stock of gas infrastructure assets. All things being equal, such a scenario would likely tighten the efficiency conditions upon which gas NSPs may propose future capex programs.

**Regulating gas pipelines under uncertainty**

Government policies on carbon pollution abatement and energy efficiency are contributing to uncertainty in the future demand for natural gas and pipeline services. The most recent capex undertaken by NSPs will depreciate over the next 50 to 80 years based on the approved economic lives of the assets. Should demand for gas decline, there is the potential for gas networks and pipelines to become stranded before the end of their currently assessed asset lives.

84 AER, Regulating gas pipelines under uncertainty, November 2021, pp.16–24.

Options to support demand for gas transportation services include repurposing gas networks or blending natural gas with zero or net-zero carbon emissions fuels, such as hydrogen or biomethane. Uncertainty currently exists around the feasibility of using the existing cohort of assets to transport hydrogen, or the price competitiveness of biomethane. Over the long-term, changes in technology or increased supply of price competitive fuel sources such as biomethane could improve the demand for gas networks and pipeline services. However, the potential risk of asset stranding still exists.

Our *Regulating Gas Pipelines Under Uncertainty information paper* released in 2021 identified options to address the implications of falling gas demand. We examined eight potential regulatory options through the lens of: (1) the current regulatory framework, (2) demand uncertainty, (3) approaches in other jurisdictions, and (4) who should pay for stranded assets.

The potential regulatory options included:

- Adjusting regulatory depreciation
- Compensating for stranded asset risk
- Removing capital base indexation
- Cost sharing under capital redundancy provisions
- Revaluation of the capital base
- Introducing exit fees
- Increasing fixed charges.
- Maintaining the status quo

Most of these options aim to reduce the uncertainty of NSPs recovering fixed costs from consumers, except for capital base revaluation and maintaining the status quo. Adjusting the timing of fixed cost recovery has intertemporal implications. For example, an adjustment to shorten the asset lives or speed up the depreciation rate of gas DNSPs' assets may increase the costs for consumers in the short term but mitigate potential price increases in the long term.

## 8.2 Asset class composition of the capital bases

A gas network's configuration and asset class composition influence its asset age profile. In this section, we present the capital base value broken down by each NSP's individual asset classification. We also provide a comparative summary of NSPs' asset classifications.

Our historical access arrangement determinations largely adopted asset classifications approved by previous regulators. These legacy asset classifications have resulted in some non-uniform asset classes and associated asset lives across the NSPs.

To simplify the analysis, we created summary asset classes that group individual NSPs' asset classifications into broader comparable asset classes. This approach helps us compare the written down value of different NSPs' capital bases by asset class. The allocation of individual distribution and transmission asset classes to these summary asset classes are presented in Appendix B.

Our analysis demonstrates the relative size of asset classes in influencing the length of time over which the capital bases will be depreciated on a straight-line basis. We present indicative asset replacement rates using our summary asset classes and actual reported replacement capex from annual RINs over 2011–2021.

### 8.2.1 DNSP capital base value asset composition

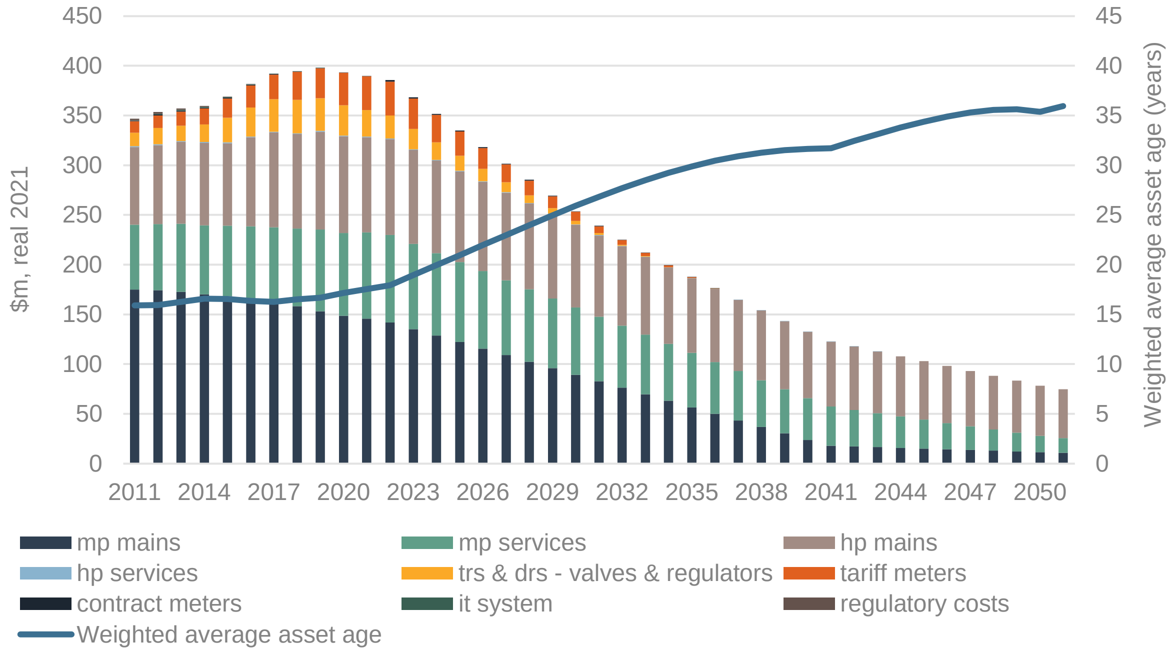
Figure 8-3 to Figure 8-9 present each DNSP's capital base value by approved asset classifications as contained each DNSP's RFM. Weighted average asset age represents the converse of the WARLs. This shows for the majority of DNSPs, the asset age declines with capex between 2011 to 2021, and then increases from 2021 onwards as no new capex is rolled into the capital base.[85]

The DNSPs' individual asset classifications create some differences in the asset age profile. However, by 2050, most capital bases will be comprised of those longer-lived assets of pipeline mains and services.

Different classes of pipeline services assets comprised 83–95% of the capital base in 2021. In 8.3.1 below, we then use the value of these pipeline services asset classes to compare the rate of replacement capex associated with these asset classes.

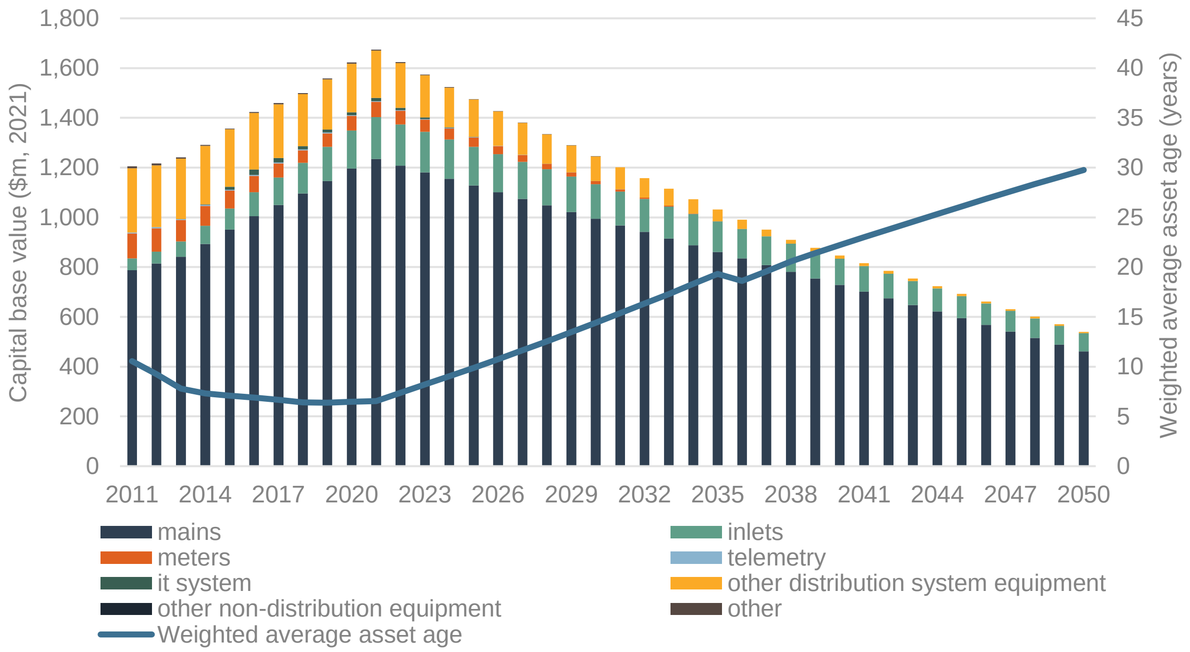
85 A gas NSP's capital base includes various assets with different economic assets lives. We modelled the capital base value and asset age on the simplifying assumption of no replacement capex to demonstrate how long it would take to depreciate the current stock of asset based on the approved standard and remaining asset lives at the time of publication. The replacement of shorter lived assets to maintain the operation of the network would be a reasonable assumption in the absence of more detailed asset age profile data.

## Figure 8-3 Evoenergy Gas – Capital base value and weighted average asset life



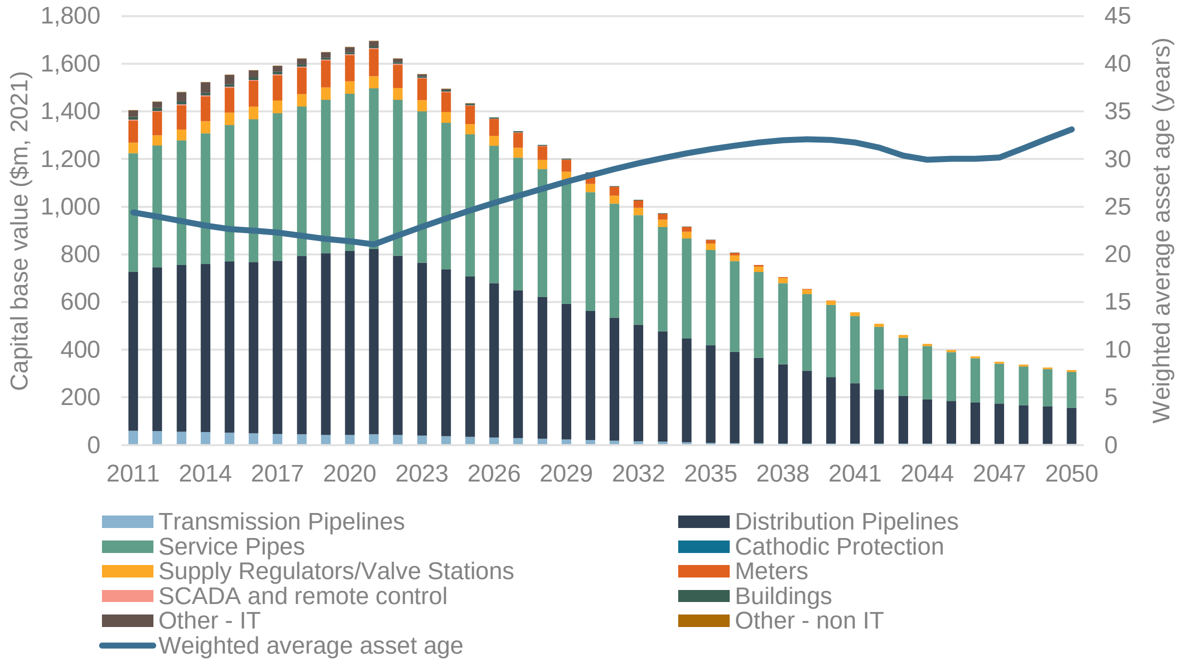

Source: AER approved RFMs and RIN data 2011 to 2021.

## Figure 8-4 AGN (SA) – Capital base value and weighted average asset life



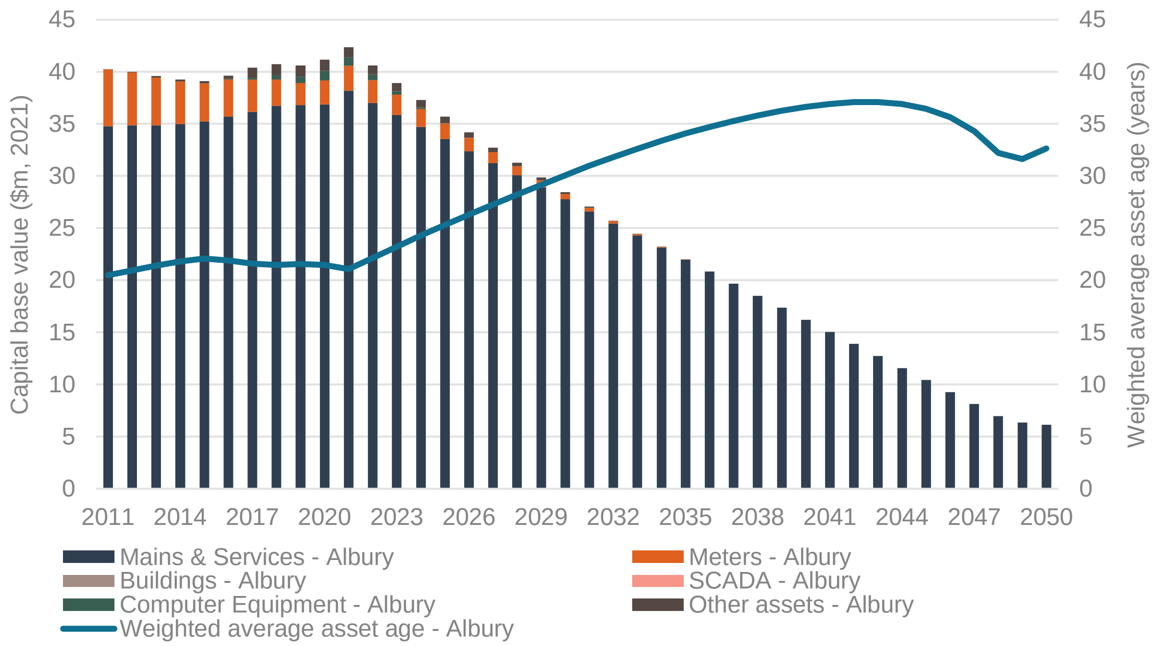

Source: AER approved RFMs and RIN data 2011 to 2021.

**Figure 8-5 AusNet Gas – Capital base value and weighted average asset life**



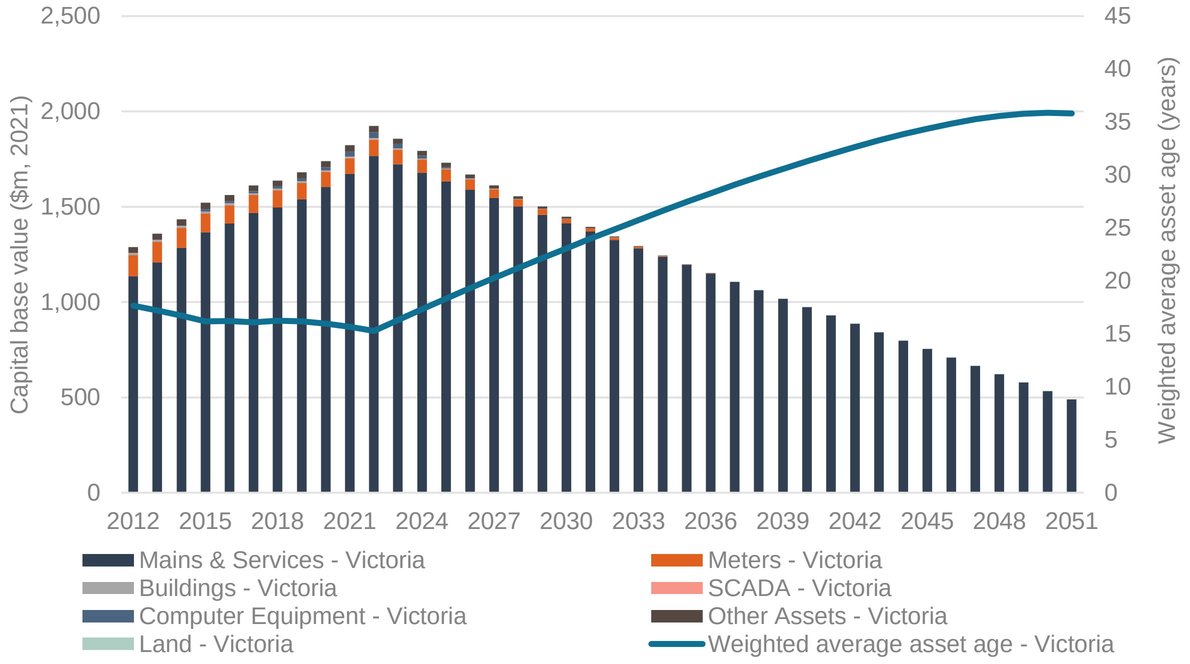

Source: AER approved RFMs and RIN data 2011 to 2021.

**Figure 8-6 AGN (Albury) – Capital base value and weighted average asset life**



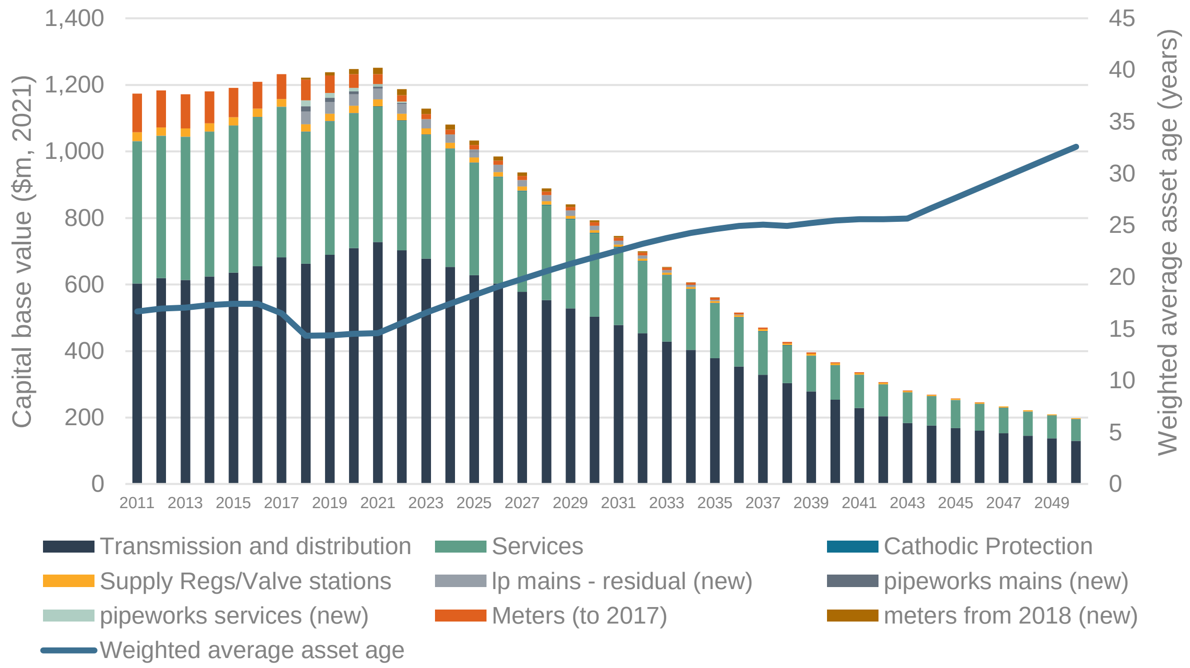

Source: AER approved RFMs and RIN data 2011 to 2021.

## Figure 8-7 AGN (Victoria) – Capital base value and weighted average asset life



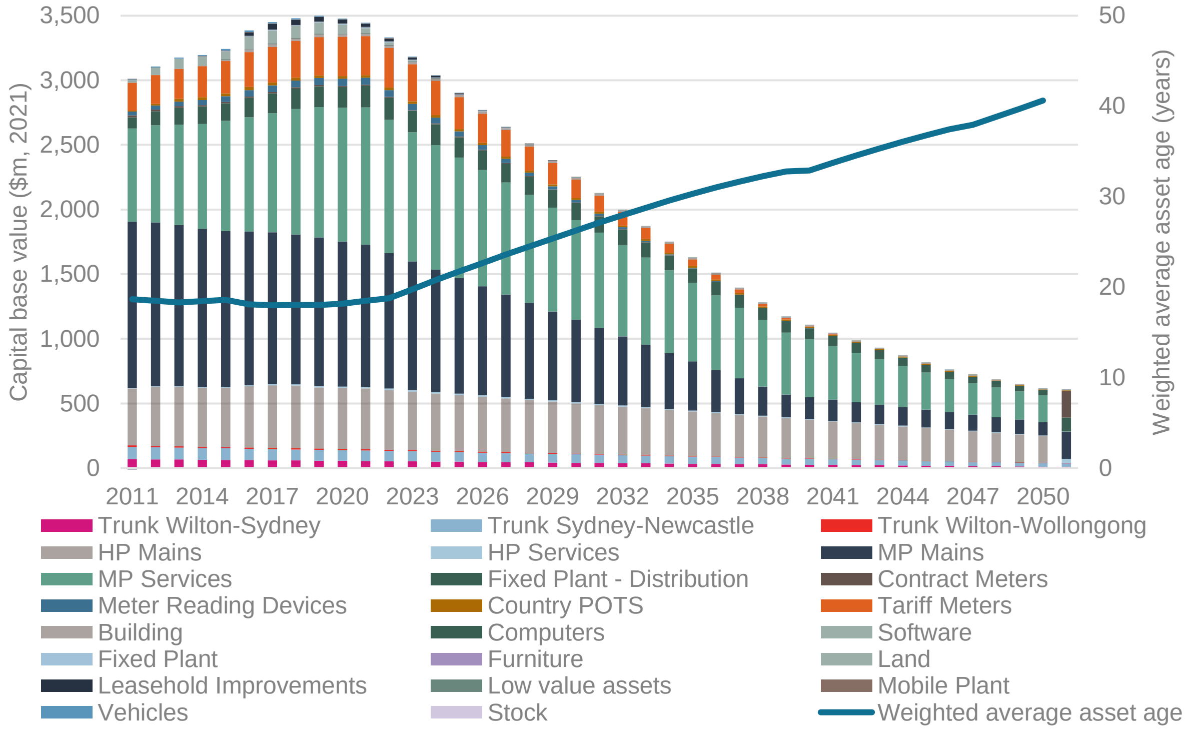

Source: AER approved RFMs and RIN data 2011 to 2021.

## Figure 8-8 Multinet – Capital base value and weighted average asset life




Source: AER approved RFMs and RIN data 2011 to 2021.

**Figure 8-9 JGN – Capital base value and weighted average asset life**



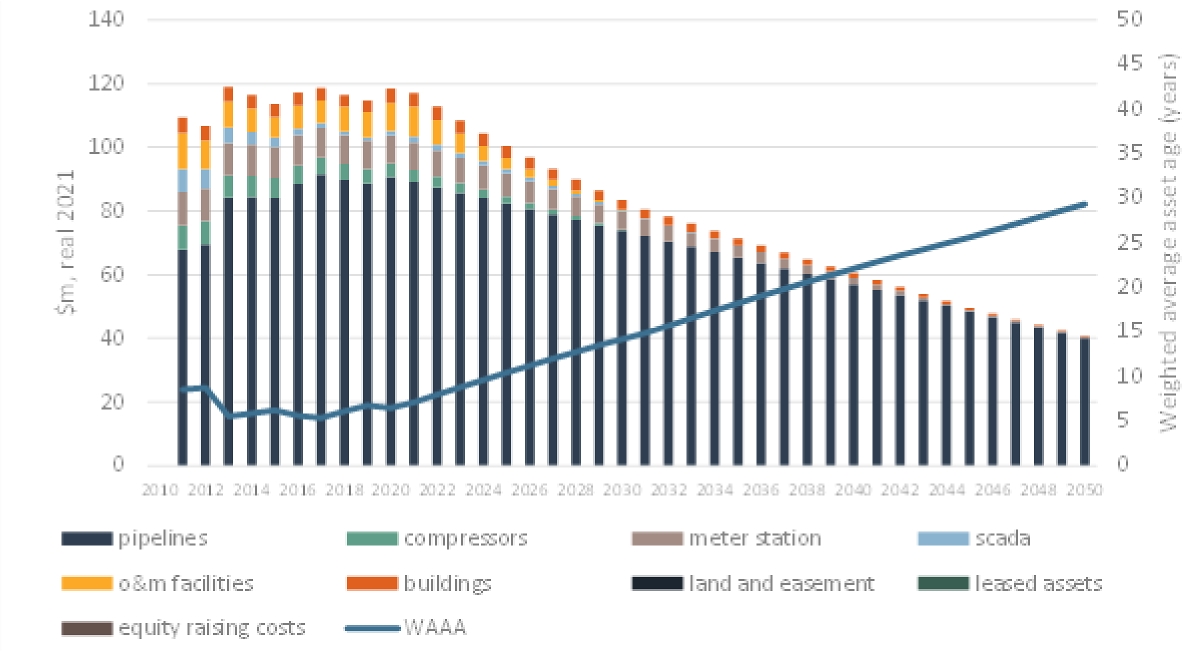

Source: AER approved RFMs and RIN data 2011 to 2021.

## 8.2.2 TNSP capital base value asset composition

TNSP capital base values are modelled on the partially as-incurred approach. This approach calculates depreciation based on the as-commissioned value of capex used to calculate the regulatory depreciation building block (return of assets). In contrast, the return on capital is calculated on as-incurred capex. The approach to transmission differs from distribution, which is based solely on as-incurred capex, this leads to timing differences when the transmission assets are commissioned and 'lumpier' capex profiles

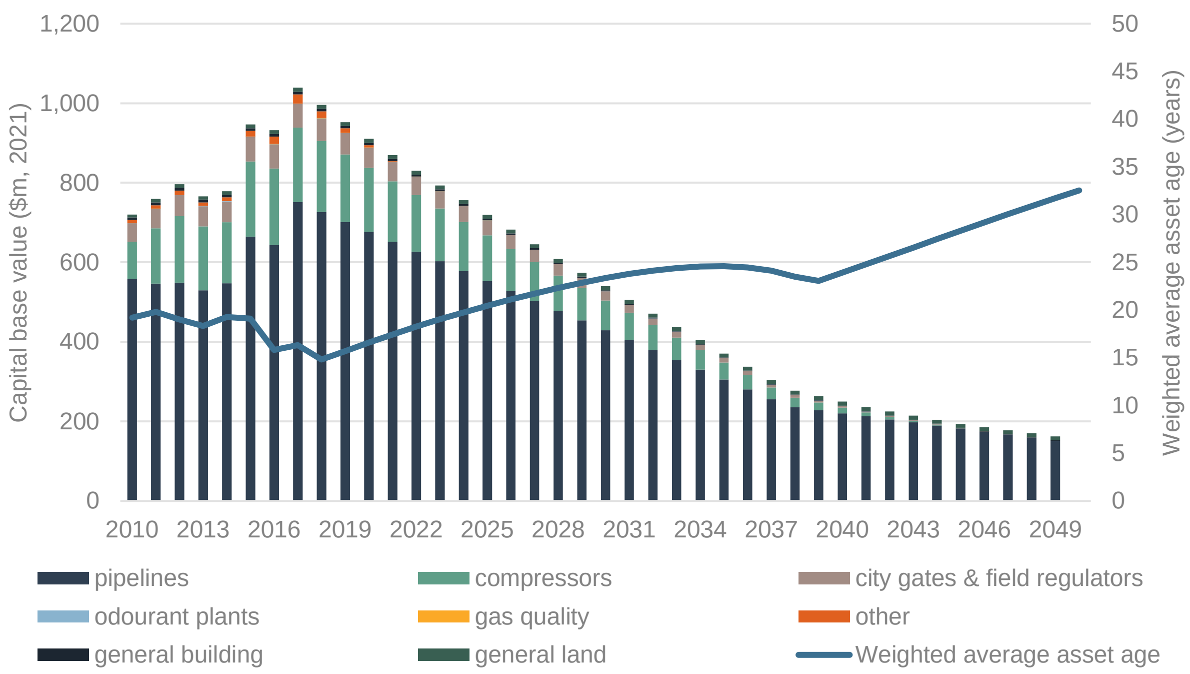
Figure 8-10 to Figure 8-12 show that for the 2010 to 2021 period, there was some variability in the asset age for TNSPs. This is due to the lumpiness of capital investment used to provide reference services when recognising capex on an as-commissioned basis.

## Figure 8-10 Amadeus – Capital base value and weighted average asset life



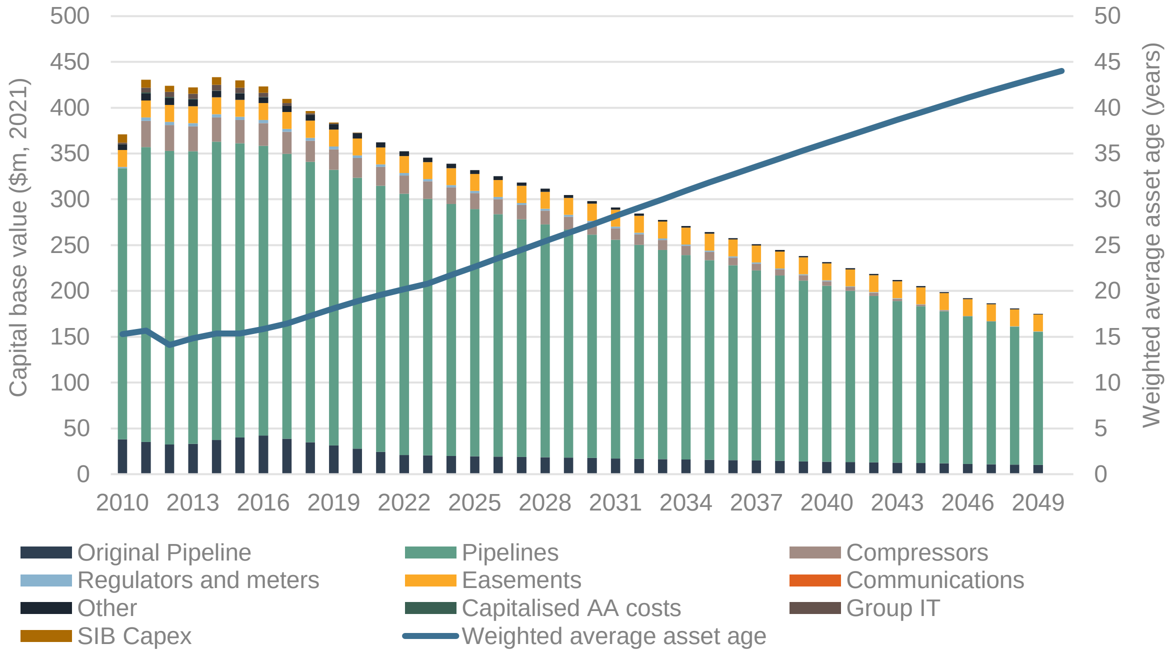

Source: AER approved RFMs and annual RIN data 2011 to 2021.

## Figure 8-11 VTS – Capital base value and weighted average asset life




Source: AER approved RFMs and annual RIN data 2011 to 2021.

**Figure 8-12 RBP – Capital base value and weighted average asset life**




Source: AER approved RFMs and annual RIN data 2011 to 2021.

As per the preceding discussion in 8.1.2, Amadeus is the youngest of the gas TNSPs with a weighted average age of 7 years, followed by VTS – 17 years, and RBP – 20 years, as at 2021.

Like distribution, the asset class with the longest life (pipelines) comprise the greatest proportion of the capital base value with relative proportions between 74% (VTS) and 87% (RBP).

## 8.3 Capital expenditure profiles and historical replacement

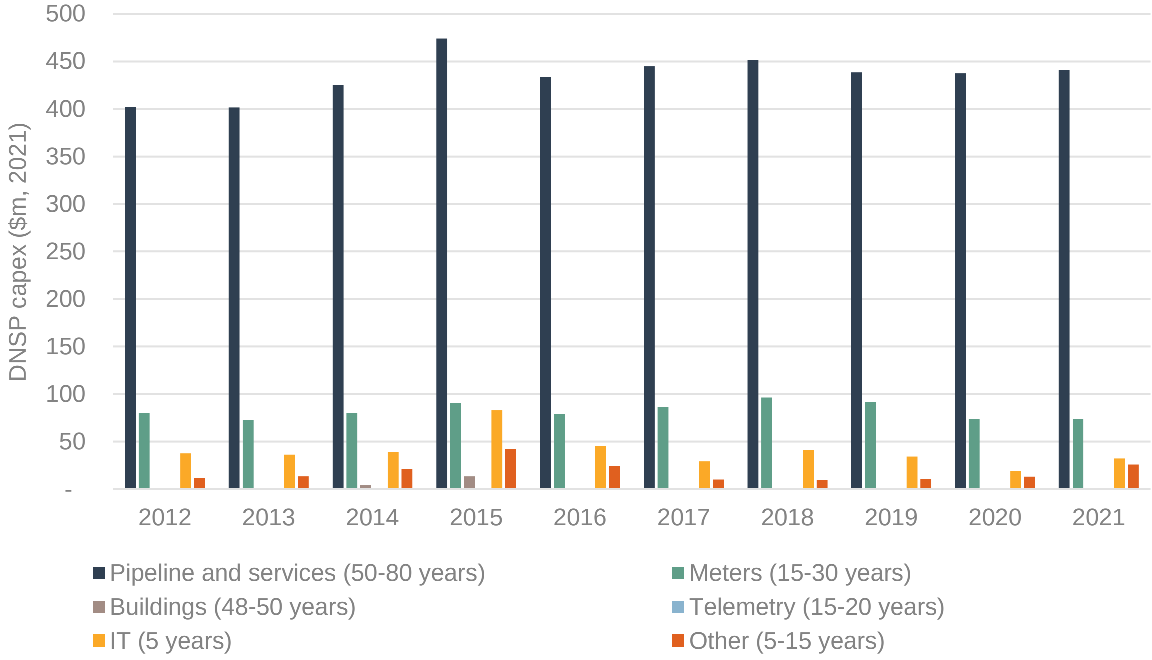
This section sets out the historical capex profiles of DNSPs and TNSPs. To compare NSPs' written down capital base values for different asset classes, we first needed to create summary asset classes. These summary asset classes group individual NSPs' asset classifications into broader categories, as reported in Appendix B.

It is also worth noting that annual reporting data differs between DNSPs and TNSPs. This affects how we can calculate replacement rates and compare written down asset values. For example, DNSPs report replacement capex for mains and services, allowing us to compare directly to the stock of asset in that class of assets. In contrast, TNSPs report replacement categories without direct reference to a class of assets. Therefore, we use the capital base as the reference written down value in the denominator when calculating the asset replacement rate for TNSPs.

### 8.3.1 DNSPs capex profile and replacement capital expenditure

DNSPs have less lumpy investment than TNSPs, due to their larger network size and configurations. In addition, capex reported by DNSPs is on an as-incurred basis as projects may be undertaken over shorter timelines or completed within a single regulatory year. This provides for a more consistent capex profile. Figure 8-13 shows the combined annual capex for 2012–2021, reported by DNSPs on an as-commissioned basis.

**Figure 8-13 DNSPs actual capex 2012 to 2021 ($m, real 2021)**




Source: AER approved RFM and annual RIN data 2011 to 2021.

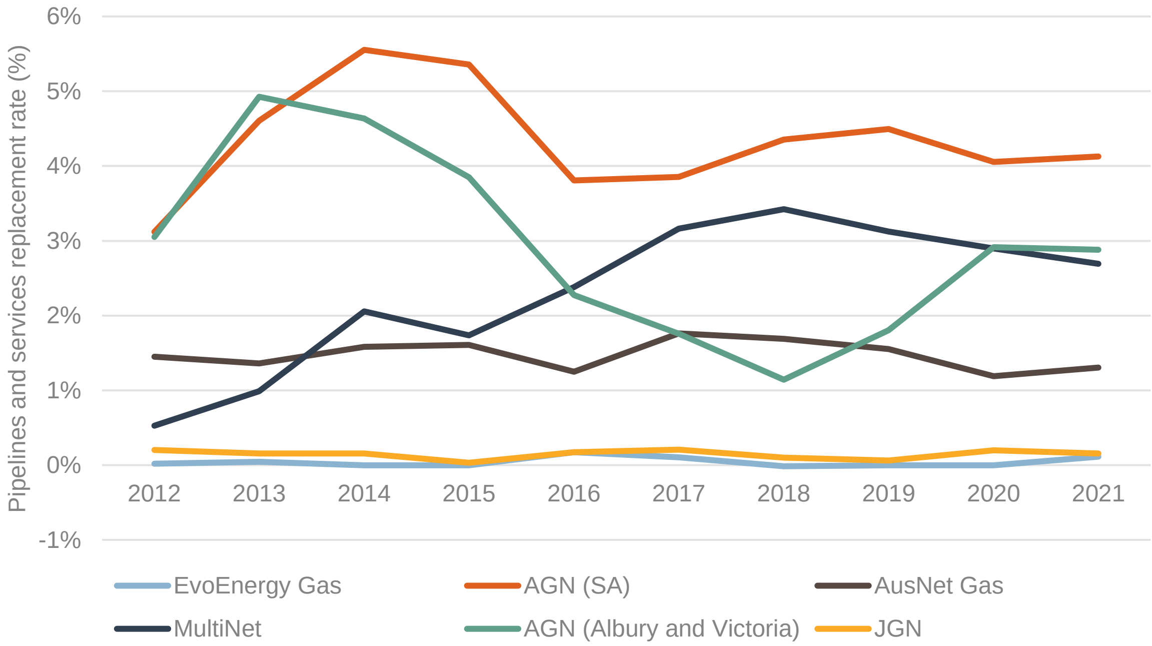
The capex profile reinforces the relative size and value of the investment in the network of pipeline mains and services compared to other shorter-lived assets. The summary asset classification identifies that pipelines and services currently in service are expected to be depreciated over the next 50 to 80 years.

Figure 8-14 presents the value of reported mains replacement capex as a proportion of the written down value of the summary asset class pipelines and services. Our analysis shows the differences in timing of individual DNSP replacement programs for mains and service pipes. AGN (SA) shows the highest rates of mains replacement average 4.3% per annum from 2011 to 2021. As reported last year, AGN’s level of mains replacement as a proportion of its total capex was 44.6% from 2011 to 2020.[86]

JGN and Evoenergy Gas have the lowest replacement rates for the period of analysis, with average rates of 0.15% and 0.04%. This is supported by the asset age analysis, which is a function of JGN and Evoenergy Gas being relatively young networks in 2011. However, their low levels of capex resulted in declining WARLs. This is not surprising given that both JGN and Evoenergy Gas report higher levels of connections capex, which is likely to contribute to a lower overall value of capex, when compared to replacing aged assets over the entire network.

86 AER, *Gas Network Performance Report*, December 2021, pp.47-48.

**Figure 8-14 DNSPs mains replacement capex vs pipelines and services capital base**

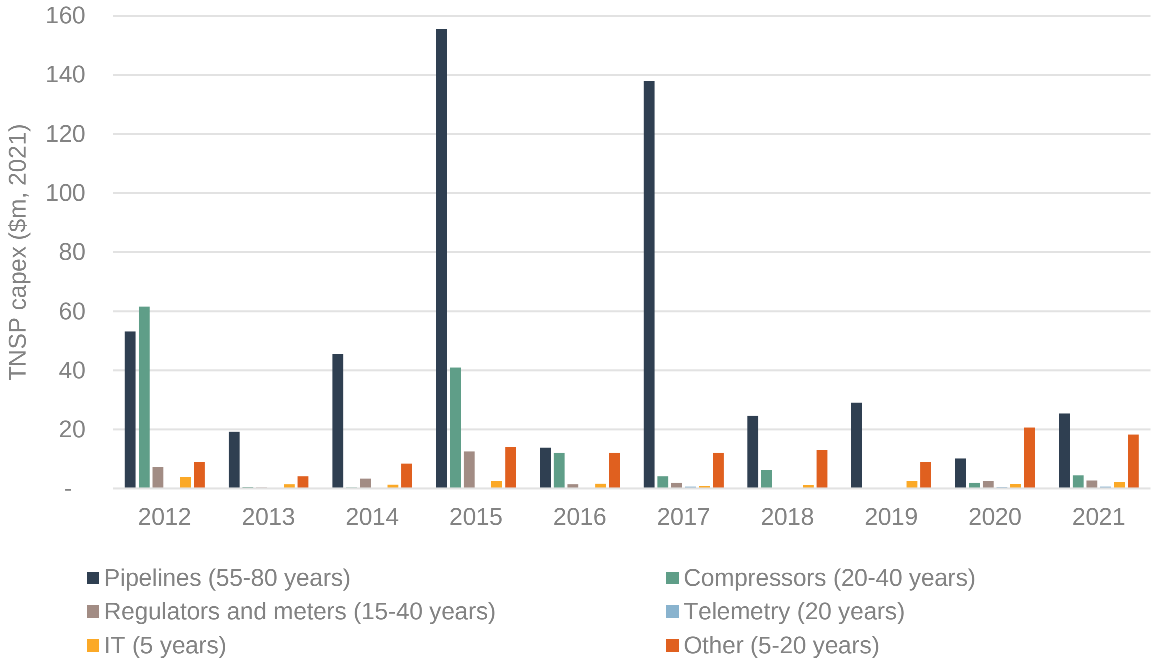



Source: AER approved RFM and annual RIN data 2011 to 2021.

## 8.3.2 TNSPs capex profile and replacement capital expenditure

Relative to DNSPs, TNSPs have fewer pipelines that are less progressively extended to connect customers. These aspects of transmission networks lend themselves to relatively large and infrequent capex programs. Figure 8-15 shows combined annual TNSP capex over 2012–2021, reported on an as-commissioned basis.

**Figure 8-15 Transmission actual capex (as-commissioned) 2012 to 2021**



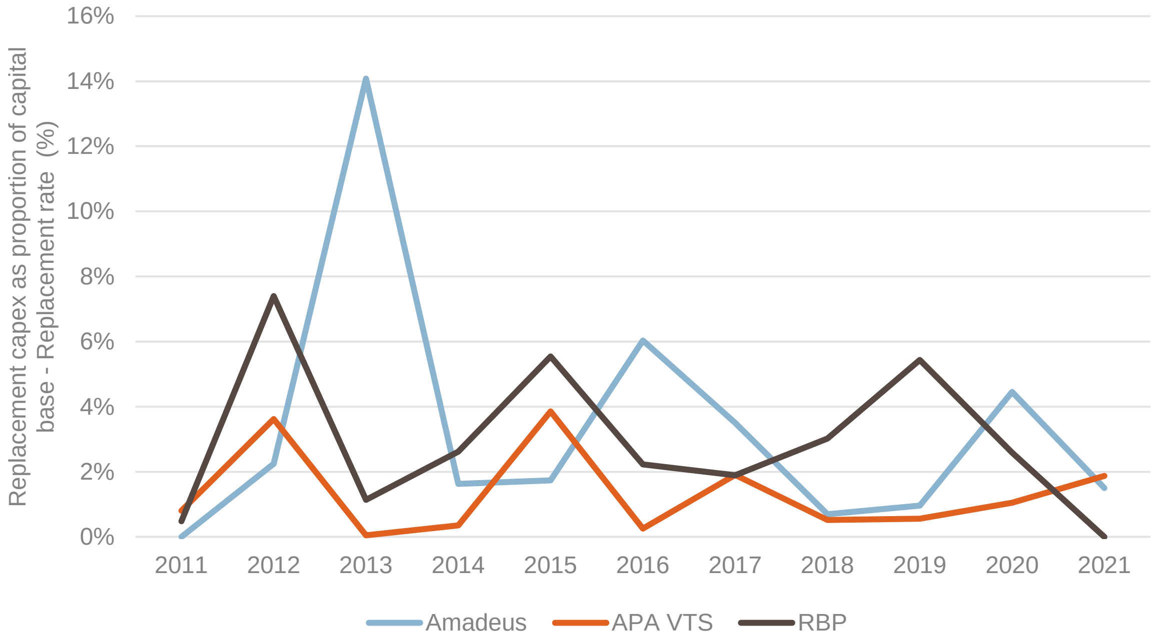

Source: AER approved RFM and annual RIN data 2011 to 2021.

As Figure 8-15 shows, TNSP capex mainly goes towards pipelines and compressors. We have estimated asset replacement rates based on past replacement expenditure reported by the TNSPs. We have measured the replacement rate of the capital base by the value of replacement capex divided by the written down value of the capital base in each year for the period from 2011 to 2021.

Capital base replacement rates shown in Figure 8-16 are highly variable, consistent with the lumpy capex profile in Figure 8-15. Transmission replacement rates show a declining trend from 2011 to 2021, with average rates of replacement falling from a high of 5.1% in 2013 to 1.7% in 2021.[87]

87 We note average replacement rates over the relatively short period of analysis may be less than indicative of actual replacement capex given the ‘lumpy’ nature of transmission investment. A large proportion of assets are long lived. When a large asset reaches end of life the replacement capex necessary to maintain service levels would translate to a higher rate of replacement capex.

### Figure 8-16 TNSP replacement capex as a proportion of total capital base




Source: AER approved capital base RFMs and annual RIN data 2011 to 2021.

Continued monitoring of capex profiles in the context of regulating pipelines under uncertainty will be of importance to users when determining the efficiency of actual and proposed capex.

# 9 Looking ahead to 2023

Each year, we aim to identify issues to be investigated in detail as our focus areas for future gas network performance reports.

Over coming years, we will revisit the focus and scope of this report in the context of gas pipeline regulatory reforms, such as those introduced into the SA Parliament in September 2022.[88] Those reforms aim to simplify the regulatory framework, more effectively constrain pipeline service providers' market power, better facilitate access to pipelines and provide greater support for commercial negotiations. As part of the reforms, we will have new gas market monitoring and reporting functions. As these reforms commence, we will work to minimise any duplication in our reporting.

In addition, as noted in our Regulating gas pipelines under uncertainty information paper, we and stakeholders are considering the impacts of the ongoing energy transition and decarbonisation objectives committed by Australian governments. Decarbonisation of the economy and more specifically the energy supply chain will have implications for pipeline services. These impacts may vary between states and jurisdictions depending on policy settings and the makeup of customer bases. Increasingly, these issues are prominent in regulatory proposals and are issues of note in our access arrangement reviews for regulated gas networks. As our decisions progress and our reporting develops, we aim to identify these emerging impacts and undertake deeper analysis of the extent to which they are impacting network performance outcomes and our decisions.

Besides those broader strategic considerations, our work this year has identified several potential focus areas for 2023 and beyond, including:

- Following from section 4.1.4, we would like to undertake a deeper analysis into demand forecasting, actual demand, and the impact this has on revenue. In 2021, we flagged that given the significance of demand on revenue, we would want to expand our analysis of actual and forecast demand in future reports. This year, we have observed that demand uncertainty is increasing and differences between forecast and actual revenue have been widening, making this a valuable topic to explore in 2023.
- Following from our discussions with consumer representatives, we would like to report on NSP actions to prepare for a low emissions future. This analysis could report on the current state of the networks (drawing on locational data were available) to better understand age, condition, hydrogen readiness and where connections are occurring.

We will engage with stakeholders to identify whether we should investigate these and/or other focus areas in our report next year. We welcome research suggestions and expressions of interest to engage from stakeholders, who can contact us at networkperformancereporting@aer.gov.au.

88 Department of Climate Change, Energy, the Environment and Water, *Energy Ministers agree final package of gas pipeline regulatory amendments*, 22 April 2022, accessed 7 October 2022. This legislation gives effect to a package of gas pipeline regulatory amendments that Energy Ministers agreed to March 2022.

# Appendix A: Objectives of network performance reporting

Through this report and the accompanying data, we intend to advance the network performance reporting objectives, determined with the input of stakeholders.[89] These are set out in Table A-1.

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

| Objective | What we are doing |
|---|---|
| Provide an accessible information resource | We have drafted this report with the intent of making it both informative and accessible for stakeholders. Alongside this report, we have published two data models covering:<br>• Our operational performance data.<br>• Our financial performance data.<br>These cover 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, in this report we have provided key performance measures which we hope will assist stakeholders in gaining preliminary views on the regulatory framework. |
| Improve accountability | The focus of this report is on the effectiveness of network regulation holistically, increasing our accountability for regulatory decisions, and for the networks and their performance under those decisions. Further, our published data allows for comparisons of individual networks and, in our published data and analysis, we highlight areas where particular networks depart from broader trends. |
| Encourage improved performance | By improving accountability and transparency, we expect these reports over time will contribute to improved performance by:<br>• Informing ourselves and stakeholders about emerging trends that may require a regulatory response.<br>• Contributing to the incentives on NSPs to improve performance. |
| Inform consideration of the effectiveness of the regulatory regime | Our analysis in this report is intended to support consideration of how the regulatory regime contributes to network performance and outcomes. We aim to explore where actual outcomes depart from forecasts or trends, whether this is widespread and what implications that has for our regulatory approaches. |
| Improve network data resources | Through our analysis of the data, we have sought to:<br>• Investigate and make use of a wide range of our network data sources.<br>• Identify and manage differences in reporting that impede comparability of data provided by different NSPs.<br>• Identify important questions on which we would like to form views but are limited by data availability or consistency.<br>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

We encourage stakeholder feedback on the report and our accompanying data resources so that we can improve its usefulness over time. Following release of the report, we encourage input from stakeholders by emailing networkperformancereporting@aer.gov.au.

89 AER, *Objectives and priorities for reporting on regulated electricity and gas network performance—Final*, June 2020.

# Appendix B: Summary asset classes

We have created summary asset classes that group individual NSPs' asset classifications into broader categories. Table B-1 and Table B-2 list these summary asset classes for DNSPs and TNSPs respectively.

**Table B-1 DNSP summary asset classes**

| Asset class (standard life) | Evoenergy Gas | AGN (SA) | AGN (Vic & Albury | Multinet Gas | Ausnet | JGN |
|---|---|---|---|---|---|---|
| Pipelines and services<br>(50 to 80 years) | Mains: MP, HP<br>Services: MP, HP<br>TRS & DRS - valves & regulators | Mains<br>Inlets | Mains & Services | Pipelines: Transmission, distribution<br>Services<br>Cathodic Protection<br>Supply Regs/Valve stations<br>LP residual (new): mains, services<br>Pipeworks (new): Mains, services | Transmission Pipelines<br>Distribution Pipelines<br>Service Pipes<br>Cathodic Protection<br>Supply Regulators/ Valve Stations | Trunk: Wilton-Sydney, Sydney-Newcastle, Wilton-Wollongong<br>Fixed Plant - Distribution<br>Mains: HP, MP<br>Services: HP, MP |
| Meters<br>(15 to 30 years | Tariff meters<br>Contract meters | Meters | Meters | Meters (to 2017)<br>Meters from 2018 (new) | Meters | Meters: contract, tariff<br>Meter reading devices<br>Country POTS |
| Buildings<br>(48 to 50 years) | n/a | n/a | Buildings | Buildings | Buildings | Building |
| Telemetry<br>(15 to 20 years) | n/a | Telemetry | SCADA | SCADA | SCADA and remote control | n/a |
| IT<br>(5 years) | IT system | IT system | Computer equipment | IT | Other IT | Computers<br>Software |
| Other<br>(5 to 15 years) | Regulatory costs | Other distribution system equipment | Other | Other | Other non-IT | Plant: fixed, mobile<br>Furniture |

| | | | |
|---|---|---|---|
| | Other non-distribution equipment<br>Other | | Land<br>Leasehold Improvements<br>Low value assets<br>Vehicles<br>Stock |

Source: AER approved roll forward models 2010 to 2021.

### Table B-2 TNSP summary asset classes

| Asset class (standard life) | Amadeus | VTS | RBP |
|---|---|---|---|
| Pipelines and services<br>(50 to 80 years) | Pipelines | Pipelines<br>Odourant plant<br>Gas quality | Original pipeline<br>Pipelines |
| Compressors<br>(20 to 40 years) | Compressors | Compressors | Compressors |
| Regulators<br>(40 years) | N/A | City gates and field regulators | Regulators and meters |
| Meters<br>(15 to 20 years) | Meter station | N/A | N/A |
| Telemetry<br>(20 years) | IT system | IT system | Computer equipment |
| IT<br>(5 years) | N/A | N/A | Group IT |
| Buildings<br>(40 to 60 years) | Buildings | General buildings | N/A |
| Land<br>(Non-depreciating) | n/a | General land | Easements |
| Other<br>(5 to 15 years) | Other | Other | Communications<br>Other<br>Capitalised AA costs<br>SIB capex<br>PMA |

Source: AER approved roll forward models 2010 to 2021.