Five year plan for our South Australian Network

July 2026 - June 2031

FINAL PLAN

July 2025

Australian Gas Networks

Contents

We are Australian Gas Networks. We deliver gas to more than 485,000 homes and businesses in South Australia every year. We do this safely, reliably and in a cost-efficient manner for our customers.

Our vision is to provide infrastructure that is essential to a sustainable energy future. We are actively participating in the energy transition by delivering the natural gas needed today and advancing solutions for tomorrow.

Since 2021, our Hydrogen Park South Australia (HyP SA) facility has been delivering blended renewable hydrogen to hundreds, then thousands, of homes. We're now planning for the next step in delivering renewable gas through HyP Adelaide.

CEO Foreword

Our Final Plan for the South Australian distribution network prioritises stability as the energy transition continues. Energy market and policy dynamics in South Australia mean we can take a measured approach to change for our next Access Arrangement (AA) — furthering our low carbon ambition and preparing for the future. This means we can offer steady prices and a sustainable energy future for the network and our customers.

This Final Plan for the South Australian distribution network outlines how we will continue to deliver safe and reliable services to our customers during a period of ongoing change in the energy sector.

At Australian Gas Infrastructure Group (AGIG) we deliver infrastructure for a sustainable energy future. Our AGN South Australian distribution network plays a crucial role in the economy and community more broadly by serving the energy needs of households, businesses and industry in Adelaide and the regions.

Customers are at the centre of our plans. This means ensuring we deliver for our customers now and into the future. Our Final Plan seeks to outline what we have delivered for our customers in the current AA period (July 2021 to June 26) and what we will deliver in the next AA period (July 2026 to June 31).

Performance in the current AA

In the current AA period, we have delivered on our goal of maintaining a customer focus. In 2024 we achieved:

- a customer satisfaction rating of 8.5, highlighting our customer focus throughout the current Access Arrangement; and
- some of the lowest incident rates across AGN for both our Total Recordable Injury Frequency Rate (TRIFR) (which decreased from 8.5 in 2021 to 2.4 this year) and Lost Time Injury Frequency Rate (LTIFR) (which decreased from 1.3 to 0.4 over the same period).

We will also have concluded our low-pressure mains replacement program by the end of the current AA period. Over the last two decades we have replaced around 3,000 km of low-pressure mains. This is an important achievement that improves safety, reduces greenhouse gas emissions and, looking ahead, ensures our infrastructure is ready for renewable and carbon neutral gases.

In the current period we also introduced our Priority Services Program for customers who are experiencing vulnerability at a time when they need us the most. With Priority Services, customers have access to a dedicated customer care team, providing access to additional support and services when needed. The program commenced in July 2023 and has helped over 140 customers experiencing vulnerability in SA so far, and will be continued in the next AA period.

These outcomes demonstrate our commitment to the safety, reliability and service expectations of our customers – a commitment we intend to maintain in the next AA period.

Customer and stakeholder engagement

Our Final Plan follows over 12 months of engagement with our customers and stakeholders.

Four key themes emerged from our engagement with customers:

- cost, affordability and price remain the key issues for most of our customers;
- customers want to ensure expenditure and investment remain at levels necessary to maintain the safety and reliability of the network;
- customers expect us to sustain the current level of excellent customer service; and
- the future of gas is important and customers remain interested in the potential of renewable and carbon-neutral gas, and how the network can contribute to reducing emissions.

In strengthening our program of engagement activities, and to promote breadth and depth of engagement, we partnered with Orbviz to design a digital and interactive version of our Draft Plan. We used Orbviz during Stage 3 and 4 of our engagement program to help connect customers and stakeholders with our proposals in a way that they have not previously been able to.

Orbviz allowed our stakeholders and customers to choose which topics they wanted to spend more time understanding, as well as providing them the opportunity to provide feedback directly.

Members of our South Australian Reference Group also commended our use of Orbviz, showcasing our desire to continue innovating the way we engage with customers and stakeholders. We will continue to use Orbviz throughout the next stage of engagement on our Final Plan.

Also, in response to our Draft Plan published on 28 March of this year, our South Australian Reference Group (SARG) challenged us to better explain:

- how we view our longer term future;
- how our proposals for the next AA period fit in with this longer term ambition; and
- how our proposals take account of, and provide appropriate flexibility, to deal with our future challenges, particularly in relation to the potential for adverse changes to local South Australian and national energy policy.

I thank all members of our SARG and Retailer Reference Group for their contribution and guidance for this Final Plan.

Plans for the next AA

Our Final Plan delivers on the themes emerging from our engagement process and after feedback on our Draft Plan. Most importantly, prices will remain steady from 1 July 2026 with a decrease of 1.0% (after inflation).

Recent inflationary conditions within the South Australian economy, and Australia more broadly, has resulted in an uplift in expenditure incurred in the later years of the current AA period. These higher costs are expected to continue into the next AA period.

That said, we are pleased that our forecast of capital expenditure is expected to decrease by 8% in the next AA period, reflecting the conclusion of the low-pressure mains replacement program by the end of this period. Operating expenditure is however expected to increase by 35%, acknowledging the impact of the COVID-19 pandemic on our operations in the current period. It also reflects in part, proposed changes to the capitalisation approach for some activities and the increased gas cost to meet our unaccounted for gas (UAFG) obligations. Overall, total expenditure (including operating and capital expenditure) is expected to increase by $78 million, or 8.6%.

Future of Gas

South Australia is at the forefront of the energy transition and our network continues to play a key role in delivering sustainable energy choices.

Our Final Plan proposes a measured approach to the energy transition — furthering our low carbon ambition and adjusting to longer-term challenges as the energy sector transitions.

Our Final Plan for the South Australian distribution network acknowledges how the future role for our network is likely to change and balances the challenges of the energy transition and opportunity by including:

- additional depreciation of around $30 million to assist the network in its evolution towards a competitive future;
- the purchase of Renewable Gas Certificates of Origin from the proposed HyP Adelaide project, which is planned to deliver 20%

renewable hydrogen by volume to the metropolitan area; and

- Renewable gas readiness expenditure of around $7 million.

This measured approach reflects the current policy settings in South Australia and is consistent with the requirements of the National Gas Rules.

Demand and Price

While we consider our networks will continue to play a role in the future energy mix, we recognise we face a more competitive environment now and into the future. Demand per residential connection has declined by more than 16% over the first three years of the current AA period as our customers invest in energy efficiency and change the way they use energy.

As behaviour and technology continue to change, we need to fine-tune the way we calculate our tariffs to enable a smooth transition to net zero emissions. Consistent with stakeholder feedback and recent decisions by the Australian Energy Regulator, we are adjusting the structure of our tariffs in part but not proposing to flatten tariffs entirely. This approach recognises customer preferences to avoid large increases in bills and unfair impacts on higher usage customers.

In developing this Final Plan our objectives are to develop a plan that delivers for current and future customers, is underpinned by effective stakeholder engagement, and is capable of being accepted by our customers and stakeholders. The Final Plan will now form the basis of a review by the Australian Energy Regulator (AER), which will include a stakeholder consultation process. I strongly encourage our customers and stakeholders to participate in the AER's process to ensure we continue to provide the services that customers value into the future.

Craig de Laine

Chief Executive Officer

Final Plan

2026/27 – 2030/31

Australian Gas Networks

Delivering a sustainable energy future for our South Australian customers

Our customers and stakeholders value:

- Keeping prices stable
- Maintaining a high level of safety and reliability
- Continuing our strong track record of customer service
- Investing for a sustainable future

Stable prices

↓ 1.0%

(after inflation)

Our plan from July 2026:

Customer Focussed

34,000 new connections

>82% customer experience performance score

A Leading Employer

Target Zero Harm across our operations

>80% health and safety performance score

Operational Excellence

>98.5% public leak reports within 2 hours

Continued replacement of multi-user services

Sustainable Communities

Continue to deliver the Priority Services Program

Connect renewable gas projects to our network

11:24

1 Plan highlights

Our Final Plan outlines the activities and investments we propose to undertake for the 2026/27 to 2030/31 period and the resulting price change for our customers.

IN THIS CHAPTER:

- **An upfront price cut for the next period of 1% builds on price cuts of 7% and 21% delivered at the beginning of the prior and current AA periods.**
- **We have a strong track record of safety, reliability and customer service in the current period.**

Customers are at the centre of our plans. Our Final Plan has been informed by our customer and stakeholder engagement program, which commenced more than 12 months ago.

This chapter summarises how we have developed our Final Plan, our achievements for the current AA period and the key elements of our proposal for the next period, 2026/27 to 2030/31.

1.1 Developing this plan

We engaged extensively with a diverse range of customers and stakeholders to understand their values, needs and expectations of the services we provide.

We held a total of 23 dedicated customer workshops; 18 face-to-face in six key regions across the state, and 5 online. 135 customers participated across all three phases. We also engaged with a diverse set of customers, including dedicated workshops with the Culturally and Linguistically Diverse (CALD) community, and stakeholders.

We published a Draft Plan on 28 March 2025 and received feedback in four formal submissions, two email submissions and at customer workshops.

This Final Plan has been informed by the feedback we received across the 4 stages of our engagement program. In particular, we have sought to meet the challenge presented by our SARG to better explain:

- how we view our longer term future;
- how our proposals for the next AA period fit in with this longer term ambition; and
- how our proposals take account of, and provide appropriate flexibility, to deal with future challenges, particularly in relation to potential negative changes to local South Australian and national energy policy.

This feedback combined with further engagement activities are reflected in this Final Plan.

1.2 Our track record

Over the current period we have met the high expectations of our customers and stakeholders, including meeting key safety, reliability and customer service standards set for our business.

Our vision is to deliver infrastructure essential to a sustainable energy future. In delivering our vision we will be customer focussed – that is continuing to deliver quality services that our customers value. Our vision is also supported by being recognised as a leading employer, delivering operational excellence and contributing to sustainable communities. During the current period we have delivered on that vision, and we aim to continue our progress during the 2026/27 to 2030/31 period.

Our key achievements during the 2021/22 to 2025/26 period so far are summarised below.

Customer focussed

- Our customer satisfaction score for AGN SA has been consistently excellent, with a score of 8.5 in 2024.
- We will have connected over 37,000 customers, bringing our total customer base to around 490,000 by the end of this period.
- 87% of emergency calls have been answered within 30 seconds.
- Our South Australian Priority Services Program (PSP) was launched in July 2023 with around 140 registrations so far, a first of its kind.

A leading employer

- In the current period, the Total Recordable Injury Frequency Rate (TRIFR) has averaged 2.4, the lowest rate achieved in AGN's history. This is a very significant improvement from a score of more than 10 reported in our previous Final Plan for AGN South Australia.
- We offer our employees up to 2 days volunteer leave each year. In 2024, our employees volunteered over 400 hours to contribute to the communities we serve, which is our highest every contribution.
- We are recognised as an Inclusive Employer by the Diversity Council of Australia 2023-24.
- As at December 2024, our workforce is evenly balanced from a gender perspective.
- In 2024, we placed 12th in the GoodCompany's "Best Workplaces to Give Back" – up from 16th place in 2023.
- 100% of compliance training has been completed within the required timeframes.

Operational excellence

- Delivered an upfront price cut of 7% (after inflation) on 1 July 2021.
- Capex is projected to be 11% lower than the benchmark, reflecting the efficient delivery of our mains replacement program and our commitment to continuous improvement.
- We will have removed all the cast iron and unprotected steel and other identified highest risk low and medium pressure mains, representing a significant milestone in enhancing network safety and reliability.
- We will complete inline camera inspections and reinforcements on HDPE 575 and DN50 mains. This will extend the service life of these mains for an estimated additional ten years.
- We are forecast to outperform our opex allowance by 21% in this AA period, even with cost pressures evident towards the end of the period.

Sustainable communities

- In 2021 we connected Hydrogen Park South Australia (HyP SA) to the existing Adelaide metropolitan network, delivering Australia's first blend of up to 5% renewable hydrogen by volume to around 700 homes.
- In 2023 and 2024 we expanded HyP SA such that it now delivers a hydrogen blend up to 10% by volume to around 4,000 homes, businesses and schools. We are currently engaging with technical regulators on a pathway to increase to higher volume blends.
- At the end of 2024, AGIG achieved an approximate 40% scope 1 emissions reduction relative to 2005 levels, on a pathway to meeting the Federal Government Target of 43% reduction by 2030.
- Our overall Risk Management Strategy and ESG Governance ensure we can continue to deliver services without interruption, and strong cyber security is an integral part of this.
- In 2023, AGIG enhanced its cyber security risk management governance as part of our Critical Infrastructure Risk Management Program, which the Board is ultimately accountable for maintaining.
- Our Reflect Reconciliation Action Plan (RAP) was launched in September 2023.

1.3 What we will deliver

Our Final Plan for the 2026/27 to 2030/31 period builds on our strong performance over the current period. We acknowledge the energy sector is undergoing major transition and take a measured approach in this Final Plan - furthering our low carbon ambition and adjusting to longer-term challenges.

We are committed to meeting our obligations and customer expectations over the next AA period. The activities and expenditure we propose to undertake in the next five years are summarised below.

Customer focussed

- We will connect around 34,000 new residential, business and industrial customers by the end of the next AA period.

- We will augment our network at the northern and southern boundaries to safeguard service levels for both existing and new customers.
- We will systematically replace ageing meters to maintain accurate customer billing. Additionally, we will install digital meters at inaccessible sites and offer customers the opportunity to opt in for a digital meter, providing greater control and transparency over their bills.
- We will improve our website and digital platform and implement analytics and functionality to optimise our customers' digital experience.
- We propose $13 million in opex savings and productivity improvement to achieve price affordability for our customers.
- We have proposed a price path that provides an upfront price cut for customers, which has the ancillary benefit of minimising price volatility in the next 5-year period.
- We have amended our tariff structure in part towards flatter tariffs (to better align with emission reduction objectives) and we have adjusted the form of revenue control (to implement a control element to the weighted average price cap when there is material revenue variation from forecast) in a manner that maintains price stability for our customers.

A leading employer

- We will continue to target zero harm throughout our operations.
- In 2024 we launched our Diversity, Equity and Inclusion (DEI) Engagement Plan for the 2024 to 2026 period and achieved a key target under the United Nations Sustainable Development Goal (SDG) 8 – Decent Work and Economic Growth.
- We will continue to invest in our employee experience and the skills of our people.

Operational Excellence

- We will continue our current program to replace Multi-User Services (MUS) sites, following the completion of 457 of the highest risk (Priority 1) MUS sites in the current AA period.
- We will insource an expiring operating contract, that importantly will enable the continued consolidation and integration under the AGIG One IT Strategy, achieving economies of scale in IT procurement, support and operational planning, as well as better security positioning.
- We will focus on critical asset integrity and risk mitigation initiatives, including the dig-up and modifications to our high-pressure transmission mains to enable Inline Inspection (ILI), and implementing measures to minimise overpressure risks at District Regulating Station (DRS).
- We will maintain our very high reliability performance, where our customers experience one hour off-supply every 40 years, on average.
- We will continue to deliver high levels of compliance with our many regulatory obligations.

Sustainable communities

We currently plan on connecting our network to HyP Adelaide, a 60MW electrolyser due for completion during the next AA period. We continue to engage with the South Australian Government on this proposal.

- We will further reduce our emissions through targeted protected steel mains replacement, lowering unaccounted-for-gas (UAFG) on the network. We have already achieved a significant reduction in UAFG through the completion of the next stage of our low-pressure mains replacement program in the current period.
- We will continue to grow the Priority Services Program to help those customers experiencing vulnerability.

Overall, our Final Plan delivers steady prices with an upfront price decrease of 1.0% (after inflation). Importantly, in before inflation (or "real") terms, the prices our customers are forecast to pay for our gas transportation services at the end of the next AA period will be consistent with that at the end of the current AA period. Our proposed price path is shown in real and nominal terms in Table 14.2.

Purpose of this plan

Regulatory framework

The National Gas Law (NGL) and National Gas Rules (NGR) provide the framework for the regulation of certain gas pipelines in Australia. This framework is enacted in South Australia through the *National Gas (South Australia) Act 2008*.

In South Australia, the Australian Energy Regulator (AER) is responsible for regulation under the NGL and NGR framework, including the approval of AA proposals and revisions every five years.

In 2023, Energy Ministers agreed to change the national energy laws to include an emissions reduction objective into the NGR, including amendments to the new capital expenditure criteria.

The AA contains our proposed Reference Services and the terms and conditions under which a customer can gain access to the South Australian distribution network.

This includes:

- the services offered on the network;
- the price paid for those services; and
- the non-price terms under which access will be provided.

Our review objectives

Our aim is to develop a plan that:

- delivers for current and future customers;
- is underpinned by effective stakeholder engagement; and
- is capable of being accepted by our customers and stakeholders.

This Final Plan will be submitted to the AER by 1 July 2025.

The Final Plan outlines the activities and expenditure we propose to undertake in the next AA period (from 1 July 2026 to 30 June 2031). It includes feedback received to date from our customers and stakeholders.

The AER will also engage with stakeholders through its own process.

How to read this plan

First, we provide important context for our plan in response to stakeholder feedback. Then, the next five chapters of this document provide an overview of our plans, our business, our stakeholders, our track record and the engagement we have undertaken to develop a plan that reflects customer and stakeholder expectations.

Each chapter then steps through the regulatory building blocks that form our required revenue and prices. These are:

- Future of Gas – consistent with the requirements of the NGR, the depreciation schedule for the next AA period, taking into consideration the impact of the energy transition on our business over time, (Chapter 6);
- Pipeline and Reference services – the Reference Services we propose to offer in the next AA period, including consideration of the AER's Final Decision (published December 2024) on our Reference Service Proposal (Chapter 7);
- Operating expenditure – the expenditure we require to run our business day-to-day (Chapter 8);
- Capital expenditure – the investment in our assets required to deliver services to our customers (Chapter 9);
- Capital base – the total value of our investment in the South Australian network (Chapter 10);
- Financing costs – the cost of financing our capital base and meeting our tax obligations (Chapter 11);
- Incentive arrangements – additional rewards and penalties that we consider should be applied to strengthen our efficiency and performance, while promoting the long-term interests of our customers (Chapter 12); and
- Demand forecasts – the total amount of services we forecast our customers will demand over the period (Chapter 13).

In the last two chapters, we outline how we have calculated the total revenue required, the resulting prices for our services (Chapter 14), and the terms and conditions for access (Chapter 15).

Context of this plan

At AGN, our Vision is to deliver infrastructure essential to a sustainable energy future. Through our Net Zero Ambition, we are committed to supporting South Australia's goal of net zero emissions by 2050 while continuing to deliver reliable and affordable energy through our networks — now and into the future.

During stakeholder engagement for the coming five-year AA period, our customers reflected on the need to balance current and longer-term pressures in the Final Plan. They told us that affordability and maintaining the safe and reliable operation of the network remain key priorities; but they told us lowering emissions from the use of our network is also important.

Similarly, in response to our Draft Plan, the South Australian Reference Group (SARG) challenged us to better explain how our proposal takes account of the energy transition and potential impacts on the network over the next AA period and beyond. This includes potential changes to the National Gas Rules and the energy policy landscape in South Australia.

This Final Plan endeavours to reflect these stakeholder expectations — by explaining how we will meet the needs of current and future customers through stable prices and reliable services, and how we address future challenges.

In the following sections we explain our longer term (post-2030) ambition for the network, how our Final Plan for the next AA period fits into this longer-term ambition and also how it can meet unforeseen negative challenges that we may encounter in the next five years. The section begins with an overview of how natural gas is used in South Australia and the distribution network today, and how we see that evolving as the energy sector transitions. It then introduces our Net Zero Ambition before considering in more detail the relatively stable policy environment in South Australia. The section concludes by considering how our Final Plan balances our Net Zero Ambition with broader energy sector challenges.

This section introduces this broader context and serves as an introduction to more detailed components of our Final Plan including:

- *Chapter 6* and *Attachment 6.1: Future of Gas and Depreciation* which details our long run demand modelling, options for our future depreciation profiles, and how the two interact; and
- *Attachment 6.4: Energy Transition* which provides further detail on our Net Zero Ambition, potential pathway to achieve that ambition and the challenges we face.

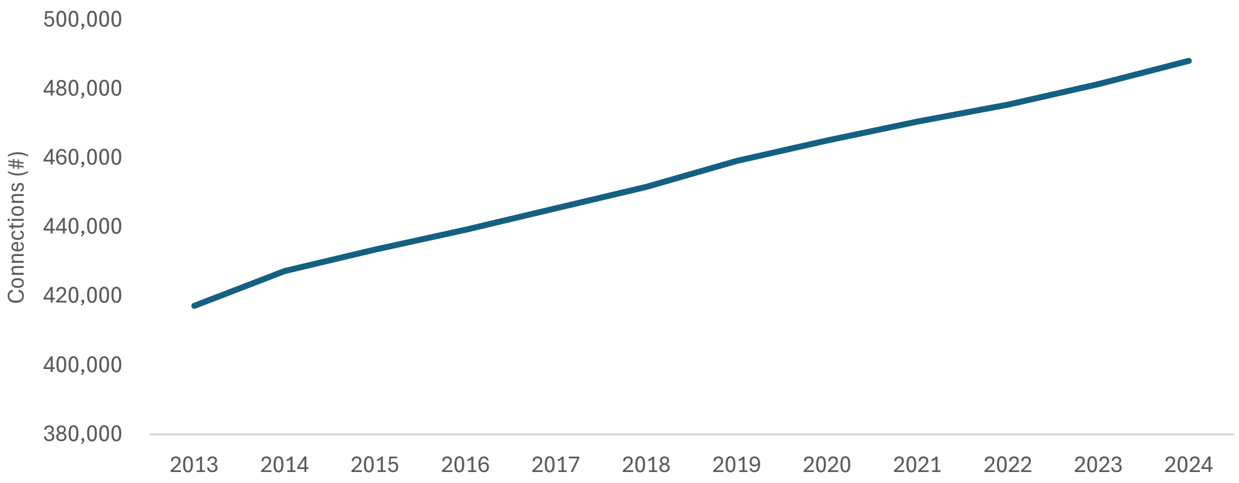
Natural gas use and our SA distribution network today

Natural gas currently supplies around 25% of South Australia's energy needs and is critical to the functioning of households, businesses and industry. About half of the gas supplied supports direct end use in homes and businesses, with the other half playing a key role in firming electricity supply.

Gas use in South Australia has shifted over the past 15 years from baseload generation to providing reliability, firming, and energy security. This continues a long history of evolution — from the transition from town gas to natural gas in the 1960s and '70s, to today's shift toward renewable and carbon-neutral gases that support emissions goals while maintaining energy choice and system resilience.

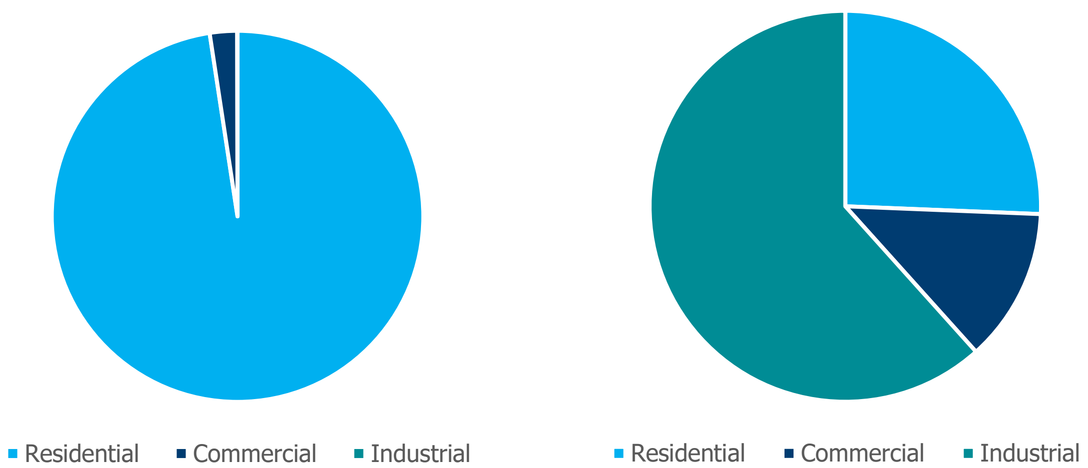
AGN safely and reliably delivers natural gas to around 490,000 residential and business customers, supporting the South Australian economy through 8,500 kilometres of network. Connection numbers have steadily increased, growing 17% since 2013 — equivalent to an average annual growth of 1% – 1.5%. In the most recent five-year Access Arrangement (AA) period we have seen demand per connection continue to decline, but the number of customer connections has continued to grow from around 465,000 to 485,000.

Figure 1.1: AGN SA Connection Growth 2013-2024



AGN SA customers are diverse in geography, scale and energy needs. Residential customers make up over 97% of connections but accounted for around 27% of total gas use in 2024. By comparison, commercial and industrial users — less than 3% of connections — used approximately 73% of total demand. This reflects the higher average gas consumption per site in the commercial and industrial sectors. Residential customers use gas for cooking, hot water, and heating, but have varying needs shaped by a combination of appliance choices, housing types, energy costs, and comfort expectations. Commercial customers include a diverse set of more than 40 different user types — from restaurants and dry cleaners, to medical services and greenhouses. Industrial customers account for the largest share of gas consumption comprising 27 different user-types — from food and beverage manufacturing, to chemicals and materials processing.

Figure 1.2 AGN SA Connections by customer type (LHS); AGN SA Total gas use by customer type (RHS)



At the close of this AA period, we expect to have effectively concluded our mains replacement program, which has seen the replacement of old low pressure cast iron mains with modern polyethene (PE) pipes. This was a multidecade, safety driven program which also has the benefit of improving reliability and making the network effectively compatible with 100% renewable hydrogen.

Natural and renewable gas, electrification and the SA distribution network in the future

South Australia leads the nation (if not the world) in the transition to renewable electricity. In 2023, 74% of the electricity generated in the state was from renewable sources, but renewable sources of energy more broadly accounted for only 17% of total energy consumption (including electricity and other direct sources of energy like fuel for vehicles and gas use in homes and businesses).

While the share of renewable electricity has increased, average gas demand per residential connection on our SA distribution network has declined, from 25GJ to 14GJ from 2002 to 2025, but as noted above, the number of connections continues to grow, adding over 120,000 connections in that time. Electrification is one reason for declining demand per connection, but other factors are as important — including improvements in gas appliance efficiency and the energy efficiency of homes and other buildings. On this basis we forecast further declines over the next AA period.

The declining demand in our forecasts aligns with both of AEMO's core scenarios in the Integrated System Plan (step change and progressive change) which see a reduction in household gas demand, but an increase in gas use for electricity generation. In Attachment 6.4, we map these scenarios against our network, to show how the network, even with reduced demand, continues to serve a diversity of customers — residential, commercial and industrial.

In planning for the future, the AEMO scenarios and our work foresees a change in the way the network is used, not a withdrawal from gas entirely.

Given the diversity of our customers, there are multiple plausible transition pathways for the SA network and our customers to achieve net zero, including biomethane, hydrogen, electrification, and the continued use of natural gas with offsets. Our scenario planning reflects this, with network futures shaped by local resources and demand. Throughout the transition, our infrastructure will support choice, security, and affordability for all customers.

In this Final Plan, we therefore need to acknowledge that customers, including those who remain on the network and new customers with different energy needs, need reliable infrastructure and pathways to net zero emissions.

Our net zero ambition

The science of climate change and its impacts on our natural and built environments are well recognised. We are committed to achieving net zero emissions from our operations and supporting our customers to do the same.

Our Net Zero Ambition is to:

- Achieve net zero emissions in our own operations; and
- Enable net zero for our customers.

We are targeting net zero scope 1 and 2 emissions across all our operations by 2050, with an interim aim to reduce our scope 1 and 2 emissions by 30% from 2020 levels by 2030.

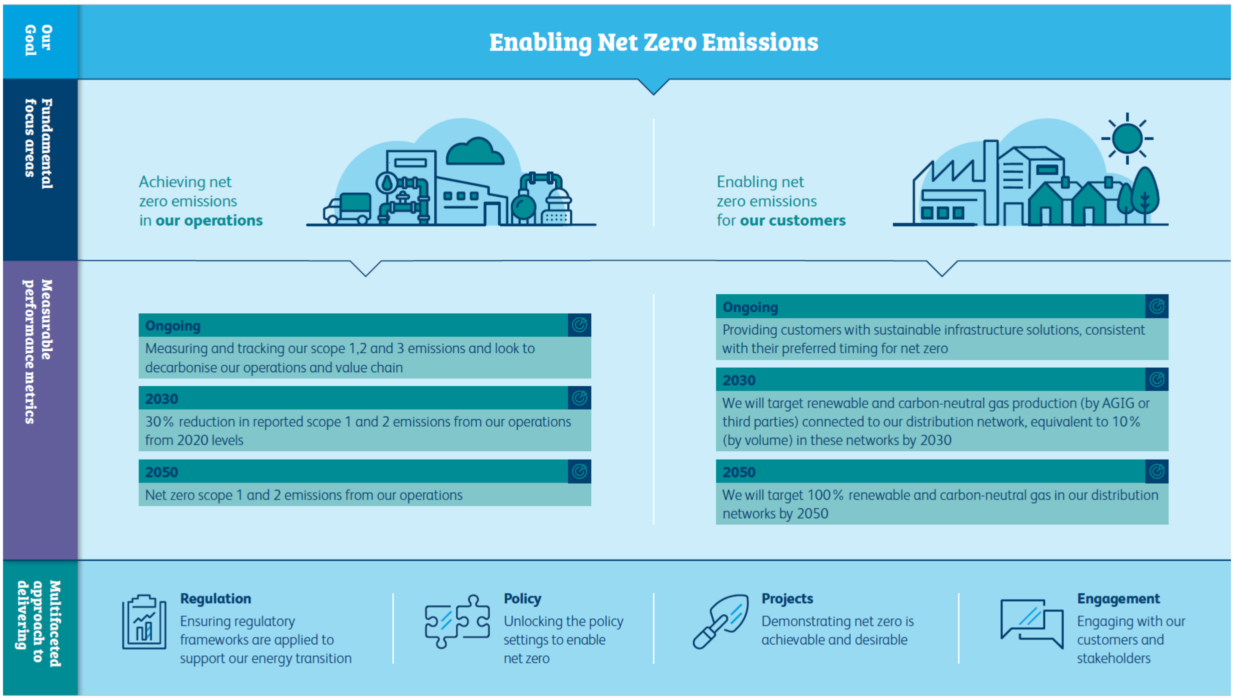
While the energy we deliver is not classified as a scope 1, 2, or 3 emissions for AGIG, our Net Zero Ambition emphasises going beyond our direct responsibilities to support our customers in their efforts to reduce emissions.

Today we are getting the network ready for renewable hydrogen and biomethane — the replacement of old pipes with polyethylene is now complete, and in the next AA period we'll undertake more renewable gas readiness activities.

Our 2030 target to have 10% blend of renewable and carbon-neutral gas (by volume) is progressing well as hydrogen and biomethane injection are enabled and expanded through various AGIG and third-party projects — hydrogen through HyP SA and the proposed HyP Adelaide project, and biomethane through the Delorean project.

Our 2050 target to transition to 100% renewable gases and carbon-neutral gas (i.e. natural gas with offsets) will be delivered through a mix of commercial-scale third-party renewable and carbon neutral gas supply, backed by a mature certification and regulatory framework.

Figure 1.3 Enabling Net Zero Emissions



Taking account of customer choices and public policy

Our Final Plan for the South Australian distribution network acknowledges the energy sector is going through a period of significant change. Public policy and consumer choice may lead to more electrification in the short term, and over the longer term will bring about fundamental changes to the whole energy sector.

In South Australia a measured approach that balances these challenges and future opportunities is possible because of several factors.

- **Energy policy is technology neutral and stable in South Australia.** Electrification and renewable gases are supported by a state government that has clearly opposed outright bans on gas appliances for homes and businesses.
- **Gas has a clear and long-term role in the energy transition.** Both of the most likely demand forecasts in AEMO's Integrated System Plan see continued, albeit reduced, gas demand for homes and small businesses. Our network will need to be affordable, reliable and safe to address the requirements of these customers in the long term.
- **Renewable and carbon-neutral gases provide options to reduce emissions today and achieve net-zero emissions in the future.** Our SA network has residential, commercial and industrial customers many of whom have no viable pathways for electrification. Renewable gases in the network provide a means of reducing emissions for customers that remain on the network.
- **We have a track record in navigating declining average consumption.** For over two decades, we have managed declining consumption, while securing relatively stable prices for our customers in South Australia.

A measured approach to the energy transition

Our Final Plan proposes a measured approach to the energy transition by including:

- **Additional depreciation** of around $30 million to assist the network in its evolution towards a competitive future and maintain balance of risk sharing in the regulatory framework.
- **Renewable gas readiness expenditure** of around $7 million.

We currently plan on connecting our network to HyP Adelaide, a 60MW electrolyser due for completion during the next AA period. This project would deliver up to 20% renewable gas by volume to the metropolitan area. We have included $8.7 million per year from 2028/29 in our opex forecast, as part of a potential jurisdictional scheme in South Australia, which would result in the network purchasing Renewable Gas Guarantee of Origin (RGGO) Certificates from HyP Adelaide.

Beyond these headline measures, our Final Plan addresses the context introduced above with adjustments across several building blocks — including depreciation, operating and capital expenditure, and demand.

Our Future of Gas and Depreciation modelling attempts to provide us with the ability to last until the competitive long-term future. It focuses on the tools we can use within the regulatory framework and builds on the work we undertook in Victoria. Based on the information we have available about technology, government policy and consumer demand, our SA network will need to respond to changing customer needs but will still be needed across a diverse customer base well into the future.

The National Gas Rules require that in presenting the Final Plan (formally called Access Arrangement Information) we use forecasts and estimates that: are arrived at on a reasonable basis; and which must represent the best forecast or estimate possible in the circumstances. The forecasts and estimates used (for demand, depreciation, and operating and capital expenditure) are aligned with current policy settings in South Australia and within the bounds of AEMO's most likely scenarios. They are also consistent with recent AER decisions.

A plan for the next five years, with opportunities to change

As well as having an eye on the longer-term future, we must also have a focus on the next five years. This requires investment and expenditure to meet:

- Customer expectations for continued reliability and affordability;
- Technical regulatory obligations to maintain the safe operation of the network for the public and our employees;
- Economic regulatory obligations to ensure prudent expenditure that serves the long-term interests of customers; and
- Business needs as we insource an expiring operating contract that will ultimately deliver efficiencies for customers in the subsequent AA period.

We will achieve this by:

- Delivering a Final Plan that keeps network prices stable; and
- Proposing a capital and operating expenditure forecast targeted at meeting our safety and reliability obligations as prudently and efficiently as possible.

While informed by forecasts stretching into the longer term, our Final Plan is for the SA gas distribution network over the next five years. If policy were to change in the next five years, the plan itself has some flexibility to adjust to changing conditions and the National Gas Rules allow for variations.

Firstly, the plan itself has flexibility to respond to changing conditions. If demand for new connections is lower our net capex will in turn reduce as growth capex won't be required. The same logic also applies if a new connection charge is introduced with the effect of reducing demand (as reflected in a current rule request before the AEMC). To the extent we are funded for additional capex within the AA period, it is only for a period of five years, and it would be offset by the lower than forecast demand.

If more material policy changes occur, the National Gas Rules provide several pathways for changes. Before the AER makes a final decision, we can propose adjustments to the AER. This recently occurred for our Victorian networks where we submitted amendments to our depreciation, capital expenditure, operating expenditure and demand forecasts, which were considered as the AER made its final decision.

Material changes during the next AA period, can be addressed through the variation process in the National Gas Rules.

Next steps

After submitting our Final Plan, the AER will provide an opportunity for customers and stakeholders to provide feedback before making its Draft and Final Decisions.

2 Our business

We deliver gas safely and reliably to more than 485,000 South Australian homes and businesses every year.

IN THIS CHAPTER:

- **We are one of Australia's largest gas infrastructure businesses.**
- **Our vision and values drive what we do and the way we do it.**

Australian Gas Networks (AGN) is part of the Australia Gas Infrastructure Group (AGIG).

2.1 About AGIG

AGIG serves over two million customers across every mainland state and the Northern Territory. Our assets include around 36,000 km of distribution networks, 4,300 km of transmission pipelines and 60 petajoules of storage capacity.

2.2 Our vision

At AGIG, our vision is to deliver infrastructure that is essential to a sustainable energy future. It is made up of four strategic pillars:

- *Customer focussed* – this means ensuring public safety and the provision of high levels of reliability and excellent customer service.
- *A leading employer* – this means ensuring the health and safety of our employees and contractors, and having an engaged and skilled workforce through leading employment practices.
- *Operational excellence* – this means getting the work done within benchmark by continually looking for ways to lower the cost of our services while delivering continuous improvement and the very high levels of reliability that our customers value.
- *Sustainable communities* – this means a commitment to long-term positive impacts on the environment and that our operations contribute to the wellbeing and resilience of the communities we serve.

The activities and investments in this Final Plan are designed to achieve these strategic pillars, and our Vision more broadly. The chapters that follow will discuss our plans in the context of these objectives alongside the requirements of the NGL and NGR.

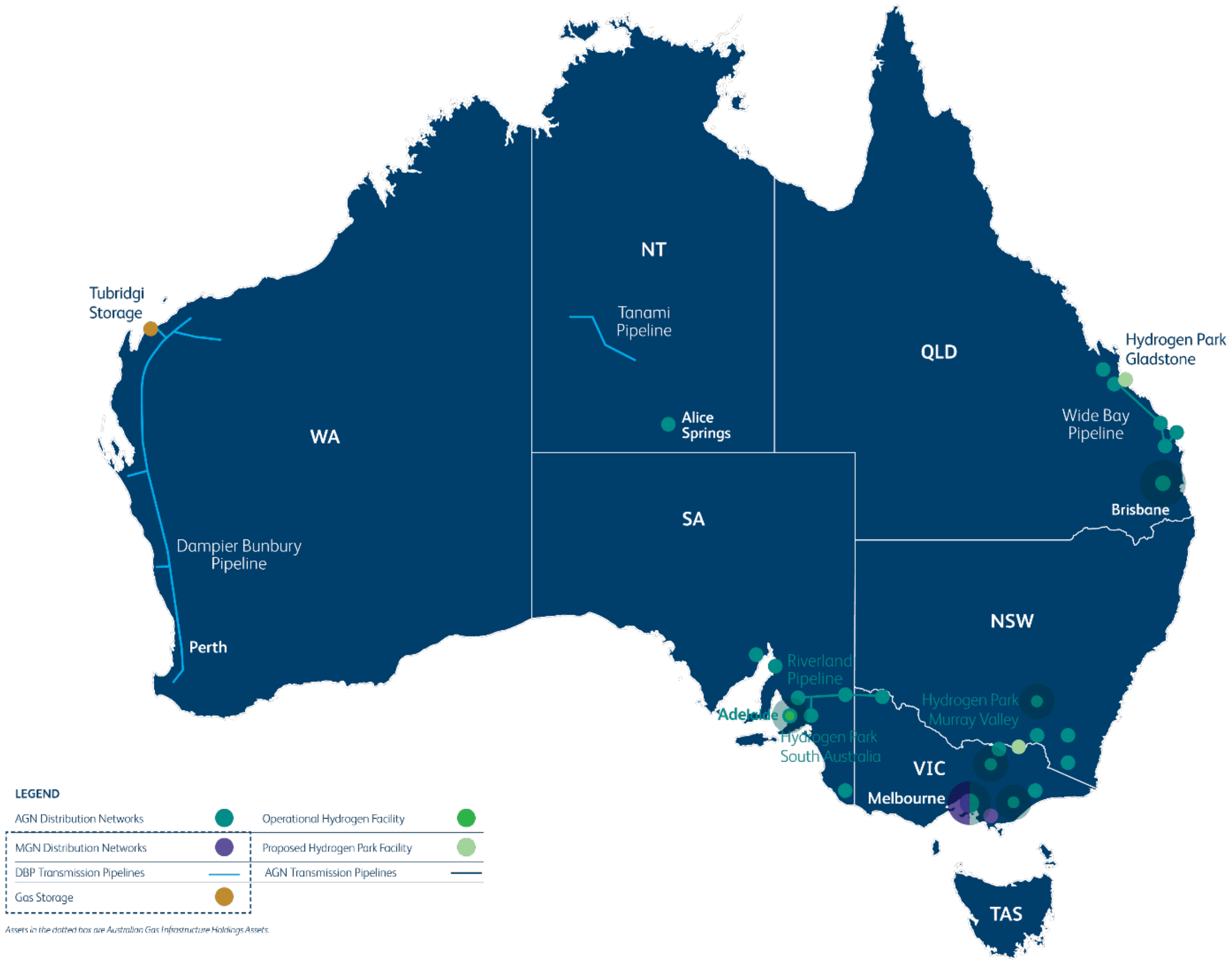
We also publicly report under our Vision, most recently in our 2024 Environmental, Social and Governance Report.

2.3 Our values

To achieve our vision, we embrace four values in everything we do:

- We build trust;
- We are accountable;
- We care; and
- We are one team.

Figure 2.1: AGIG's operations across Australia



2.4 Delivering for customers first

A central element of AGIG's vision is to be customer focussed. We know that if we do not deliver for our customers on safety, reliability, customer service, price and sustainability they will choose other energy solutions.

Furthering our commitment to put customers at the centre of our business, we are proud to be a founding member of the Energy Charter – giving extra visibility and accountability to this commitment.

This commitment reflects our ongoing practice of engaging with customers and stakeholders, including publication of a Draft Plan prior to formal lodgement of our Final Plans with the AER. In developing this Final Plan, we have engaged with our customers through a number of activities.

This engagement process has enabled customers and other stakeholders to inform and shape our proposals. The outcomes of this process are explained throughout this document, while the stakeholder engagement program is detailed in Chapter 5.

Our Role in the Gas Supply Chain

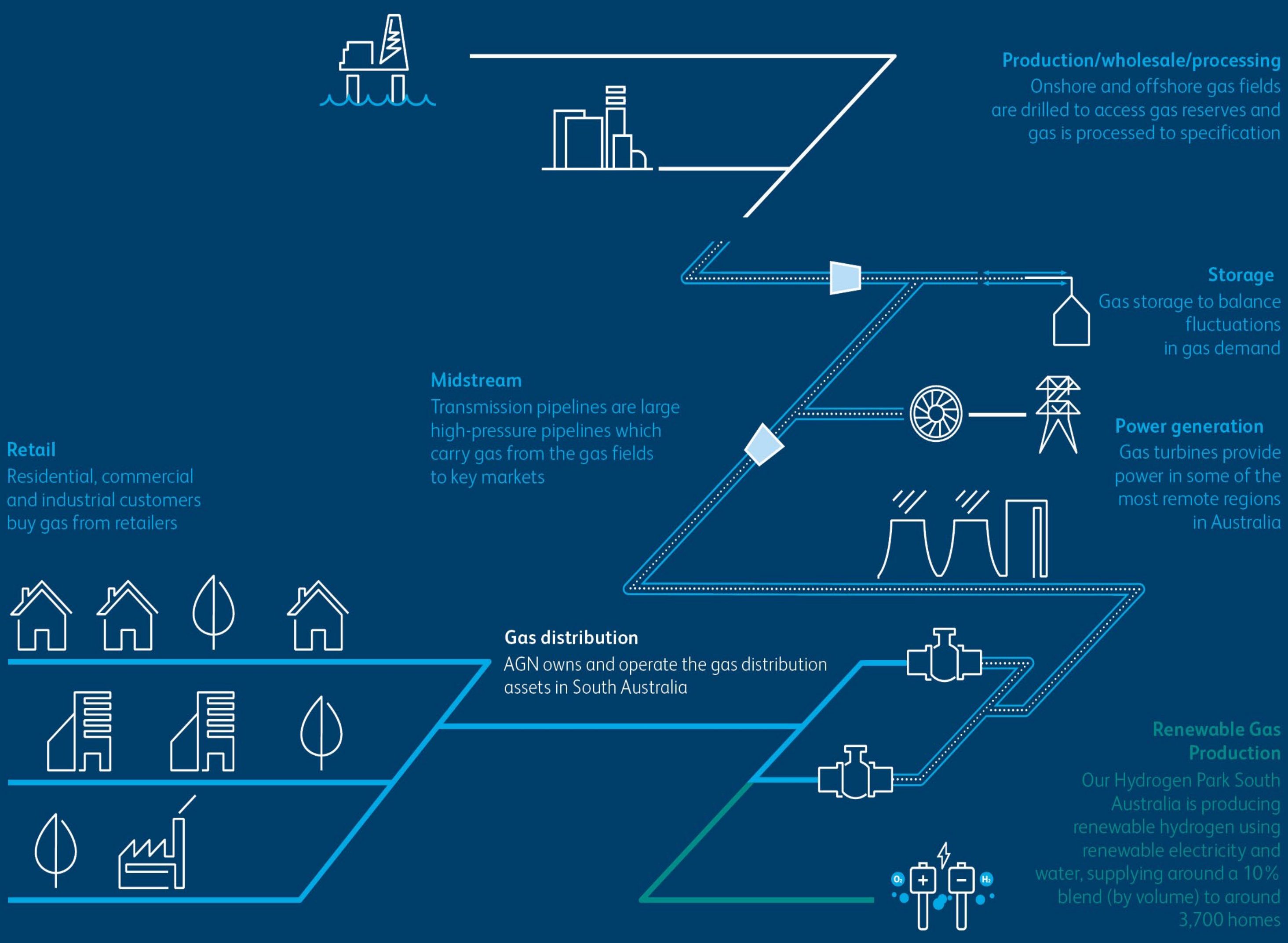
We own and operate the gas distribution infrastructure that delivers gas across South Australia.

We don't own gas, we transport it. We service the needs of Producers, major energy users and residential and business users by transporting gas from those who produce it to those who use it.

Our customers choose their gas retailer, who purchase the gas on the customers' behalf. The gas is transported through transmission pipelines and our distribution networks to customers' premises. Retailers pay network charges to the transmission and distribution network businesses and recover these costs from customers through their retail gas bills.

Our customers might interact with us on the following occasions:

- to obtain a new gas connection
- if they experience an outage that is either planned or unplanned
- to report a gas leak
- if they are experiencing an issue with their meter or when their meter is being read
- upgrades or maintenance are occurring in their street or community
- they have a general enquiry or complaint about their gas supply or service.



Our Vision

To deliver infrastructure essential to a sustainable energy future

Our Strategic Pillars

Customer Focussed

- Public Safety
- Customer Experience
- Cost Efficient

A Leading Employer

- Health and Safety
- Employee Experience
- Skills Development

Operational Excellence

- Profitable Growth
- Benchmark Performance
- Reliability

Sustainable Communities

- Enabling Net Zero
- Environmentally Focussed
- Socially Responsible

Our Values

We build **Trust**

We are **Accountable**

We **Care**

We are **One Team**

2.5 Zero Harm

Maintaining the safety of our workforce and the public is always the central focus of all our activities. When developing our Final Plan and the work programs that underpin it, our aim is to do everything we can to meet the obligations of our safety case and asset management strategies.

We are continually striving to achieve Zero Harm and have comprehensive health and safety policies, procedures and training that support the delivery of this ambition. We have made good progress in the current AA period, where injury rates are the lowest they have ever been.

Our safety focus was also recognised by the Australian Pipelines and Gas Association, where we received the 2024 Safety Excellence award in recognition of our underground asset location work.

Our Zero Harm Principles (shown in Figure 2.2) highlight areas of risk in our operations where we have non-negotiable rules for our staff and contractors to follow. These are essential to keep our workforce and the public safe. They also help us create a strong safety culture where every employee is personally committed to managing health and safety.

Figure 2.2: Our Zero Harm Principles

2.6 The gas supply chain

AGIG owns and operates gas infrastructure, including transmission pipelines, distribution networks and gas storage facilities across Australia. Our assets play an important role in the safe and reliable supply of gas to customers at various parts of the gas supply chain. Our gas transmission assets also provide a key role in electricity generation in Western Australia. Key components of the gas supply chain include upstream production and processing, transmission, distribution, storage and downstream consumption.

Our customers purchase gas from retailers, which is delivered directly to them by our South Australian distribution network.

2.7 Our role in South Australia

Natural gas plays a pivotal role in South Australia, providing a reliable source of energy for homes, businesses and power generation. Gas represents almost 40% of the total energy consumption in the state.

Figure 2.3 shows the location and key features of our South Australian distribution network. The network is more than 8,100 km long, serving residential, commercial and industrial business customers in Adelaide (from Two Wells to Aldinga) and regional centres in the Upper North, Barossa, Riverland and south-east of the state inclusive of Mount Gambier.

AGIG is also at the forefront of the emerging hydrogen industry in Australia through our investment in Hydrogen Park South Australia (HyP SA). HyP SA is a key part of our vision to deliver net zero, by developing and implementing a pathway to zero emissions for our South Australian distribution network.

Figure 2.3: SA gas network

3 Our track record

In the 2021 to 2026 period, we have continued to deliver the strong safety, reliability and service standards expected by our customers.

IN THIS CHAPTER:

- **We are close to concluding our low pressure mains replacement program with the replacement of 704km of low pressure mains over the period, improving safety, reducing greenhouse gas emissions and delivering infrastructure ready for renewable and carbon neutral gases in the future.**
- **We have connected and expanded Hydrogen Park South Australia, which now delivers a 10% renewable hydrogen blend to more than 4,000 customers on our SA distribution network.**

During the current AA period our focus has been on safety, customer service, minimising costs and completing our mains replacement program.

Our activities have been guided by our vision, to deliver infrastructure for a sustainable energy future. Our activities in the current period contribute to the four pillars of our vision: customer focussed, a leading employer, operational excellence and sustainable communities.

3.1 Customer focussed

Customer focussed means ensuring public safety and the provision of high levels of reliability and customer service in a cost efficient way.

Under this pillar our targets have included responding and repairing leaks within set timeframes, customer satisfaction in delivering distribution services and our mains replacement program.

In the current period to date, we have delivered against these targets by:

- Strong public safety performance – responding to 99% of publicly reported leaks within 2 hours;
- Very high reliability – our customers experience one hour off supply every 40 years, on average;
- 91% of emergency calls were answered within 10 seconds in 2024; and
- Customer satisfaction scores have been consistently high, with a score of 8.7/10 in 2024.

3.2 A leading employer

Being *a leading employer* means ensuring the health and safety of our employees and contractors, and having an engaged and skilled workforce.

In this pillar our targets have included safety and employee engagement performance.

In the current period to date, we have delivered against these targets by:

- Achieving very significant improvements in our Total Recordable Injury Frequency Rate (TRIFR), which has averaged 5.4 in the current period. This is a substantial improvement from a score of more than 10 reported in our last Final Plan for AGN South Australia. Injury rates are currently the lowest they have been in our history;

- We continue with our health and safety initiatives, including annual zero harm workshops, a HSE culture model and reporting and recognition awards for safety performance; and
- 100% of compliance training has been completed within the required timeframes.

3.3 Operational excellence

Operational excellence means getting the work done within benchmark levels by continually looking for ways to improve cost of service through efficiency, quality and continuous improvement.

In the current period to date, we have delivered against these targets by way of the following:

- Delivering a price cut of 7% to our customers on 1 July 2021;
- Completing our low-pressure mains replacement program by the end of current AA period. This is the conclusion of a multi-decade program replacing more than 3,000km of pipelines. This safety driven program has the added benefit of making the network ready for 100% renewable gases;
- Responding to 99% of public leak reports within 2 hours;
- Capex is expected to be 14% below allowance, reflecting our efficient delivery of the mains replacement program and focus on continuous improvement; and
- Opex is expected to be 21% below our allowance, reflecting lower unaccounted for gas (UAFG) following our low pressure mains replacement program and general operational efficiency ahead of emerging cost pressures at the end of the period.

3.4 Sustainable communities

Sustainable communities means ensuring we are environmentally and socially responsible in the way we provide services.

Under this pillar our targets have included taking the first steps to develop options for the long-term future of the South Australian distribution network.

In the current period to date, we have delivered against these targets by:

- Capturing ESG information from 2024 as part of our procurement processes for major projects;
- Delivering our Priority Services Program in 2023, which has supported around 140 SA customers experiencing vulnerability;
- Completing our low-pressure mains replacement program, which has driven UAFG to record low levels; and
- Connecting and expanding HyP SA, which now delivers a blend of up to 10% renewable hydrogen to more than 4,000 customers on our SA distribution network.

4 What we will deliver

This Final Plan supports our Vision to deliver infrastructure for a sustainable energy future in the 2026/27 to 2030/31 period.

IN THIS CHAPTER:

- **We will deliver stable prices into the next AA period for customers recognising the current cost of living pressures being experienced by the community.**
- **We will connect around 34,000 customers to the network in the next AA period.**
- **We will adjust to future challenges for the network with additional depreciation of around $30 million.**

Our Final Plan sets out how we will continue to provide affordable, safe, reliable and sustainable gas distribution services today and for the future in South Australia.

Our activities for the next AA period will be guided by our Vision, to deliver infrastructure for a sustainable energy future. Our activities will contribute to the four pillars of our vision: customer focussed, a leading employer, operational excellence and sustainable communities.

4.1 Customer focussed

Customer focussed means ensuring public safety and the provision of high levels of reliability and customer service.

In the next AA period, we will deliver on this pillar by:

- Responding to public leak reports within 2 hours more than 95% of the time;
- Repairing leaks within the timeframes set by our Leak Management Plan 100% of the time;
- Achieving customer experience scores at or above 81%;
- Connecting around 34,000 new residential, business and industrial customers;
- Proceeding with the medium risk Multi-user Services (MUS) renewal following the completion of highest risk MUS in the current AA period;
- Ensuring accurate billing through systematically renewing ageing meters and introducing digital meters in hard-to access locations, while also giving customers the option to switch to digital meters for better bill management;
- Insource an expiring operating contract, that will importantly enable the continued consolidation and

integration under the AGIG One IT Strategy, achieving economies of scale in IT procurement, support and operational planning; and

- Enhancing digital customer services by upgrading our website with online tools and analytics to offer bill saving estimates and cost-effective online repair solutions.

4.2 A leading employer

Being *a leading employer* means ensuring the health and safety of our employees and contractors and having an engaged and skilled workforce.

In the next AA period, we will deliver on this pillar by:

- Continuing to target zero harm and reinforcing our HSE culture;
- Switching our focus from lagging indicators to leading indicators of employee safety; and
- Continuing our health and safety initiatives, including our various wellbeing initiatives.

4.3 Operational excellence

Operational excellence means getting the work done within benchmark levels by continually looking for ways to improve cost of service, pursue growth and maintain very high levels of reliability.

In the next AA period, we will deliver on this pillar by:

- Delivering an upfront price cut of 1.0% (after inflation) on 1 July 2026, which builds on our price cuts delivered in prior AA periods of 7% and 21%;
- Continuing to target our long-standing reliability of the network with limited disruption to our customers;
- Connecting around 34,000 new customers and 255 km of new mains length into the network; and
- Incorporating a productivity adjustment and other savings into our operating expenditure forecast, altogether valued at $13 million.

4.4 Sustainable communities

Sustainable communities means ensuring we are environmentally and socially responsible in the way we provide services.

In the next AA period, we will deliver on this pillar by:

- Continuing to support customers experiencing vulnerability through our Priority Services Program;
- Enabling renewable gas opportunities such as HyP Adelaide (see Box 4.1) to bring renewable gases into the network;
- Including additional depreciation of around $30 million to assist the network in its evolution towards a competitive future and maintain balance of risk sharing in regulatory framework; and
- Replacing protected steel sections of the network.

About Hydrogen Park Adelaide

Hydrogen Park South Australia (HyP SA), located in the Tonsley Innovation District, was successfully delivered in the current AA period, demonstrating our ability to safely deliver renewable hydrogen to around 4,000 customers through the existing gas distribution system.

We are working on the next step in decarbonising South Australian gas supply, which includes the potential for Hydrogen Park Adelaide (HyP Adelaide).

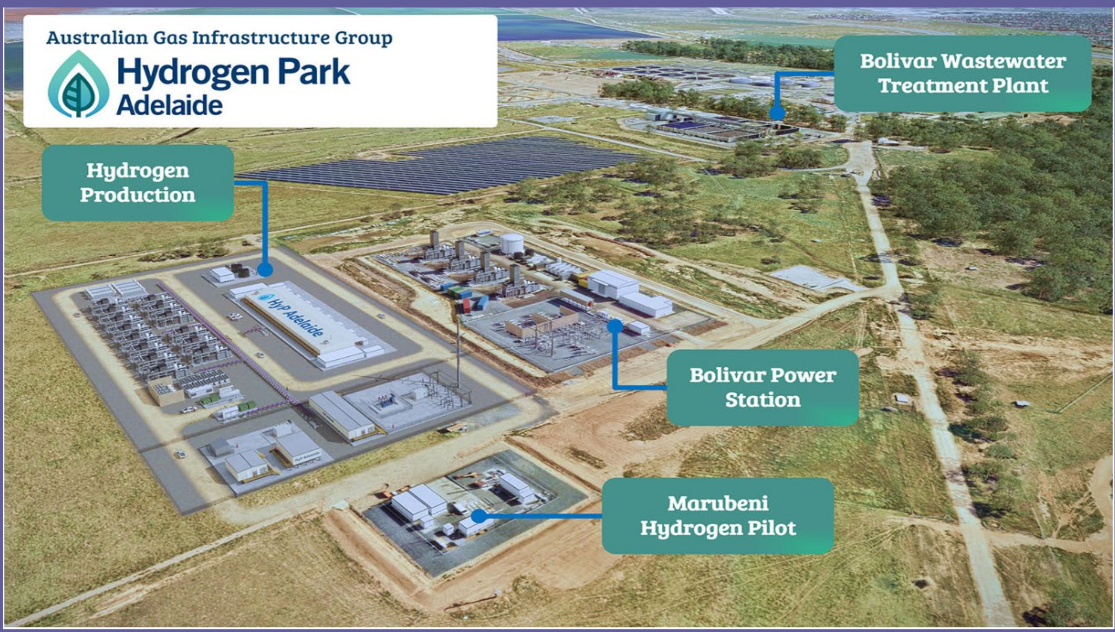
HyP Adelaide is a proposed 60 MW renewable hydrogen production facility located at SA Water's Bolivar wastewater treatment plant, that will aim to produce up to 900 TJ per year of renewable hydrogen. HyP Adelaide is proposed to be Australian Gas Infrastructure Group's next key milestone, building on the capability and knowledge developed in delivering HyP SA and Hydrogen Park Murray Valley.

HyP Adelaide intends to deliver hydrogen to the Gepps Cross city gate via a new pipeline. The gas will then be blended at up to 20% by volume into Adelaide's distribution networks, supplying over 485,000 customers.

HyP Adelaide would assist with decarbonisation of gas supply in Adelaide and enable large industrial customers to offset their gas usage by acquiring renewable gas certificates generated by reference to renewable hydrogen produced at the facility. Renewable hydrogen could also potentially be supplied to the Bolivar Power Station adjacent to the site, blended into its gas supply at up to 25% by energy. The renewable hydrogen would assist by providing a lower carbon option to help firm South Australia's electricity grid.

In addition, we are exploring other opportunities to supply oxygen and waste heat generated by the facility to industrial customers.

We are liaising with the South Australian Government on policy support to help deliver the project. The impact of the policy being explored has been estimated and included in our operating expenditure forecast (see chapter 8). Importantly, network prices remain stable for our customers through the next AA period.




Australian
DEBORAH
KERRY
NEW GAS CONNECTION

5 Customer and stakeholder engagement

Our Final Plan incorporates what our customers and stakeholders have told us is most important to them throughout the extensive engagement program that we have undertaken. This Final Plan underpins our commitment to put customers at the heart of everything we do.

IN THIS CHAPTER:

- **Engaging with our customers and stakeholders to understand how they wanted to be involved in the development of our plans.**
- **Holding iterative workshops with key customer groups, including residential, business, culturally and linguistically diverse (CALD) customers, to understand their needs and preferences.**
- **Designing and delivering bespoke engagement activities around key issues of importance for different stakeholder groups.**
- **Our partnership with OrbViz to design and deliver an interactive digital engagement tool to engage on the Draft Plan to promote breadth and depth of engagement.**

We have listened to and learned from our customers and stakeholders as we have refined this Final Plan to ensure it captures what is important to South Australians.

We have collaborated with our stakeholders to provide transparent information in-line with our commitment that there are 'no surprises' in our proposals.

Our engagement does not end with the submission of our Final Plan to the AER. We will continue to engage on our plans to deliver on what matters most to our customers and stakeholders.

This chapter outlines how our engagement activities to date have informed and shaped our proposals.

5.1 Overview

Our objective is to develop a Final Plan which delivers for current and future customers, is underpinned by effective stakeholder engagement and is accepted by our customers and stakeholders.

Throughout the development of our Plans, we adopted a five stage approach to our engagement program which is illustrated in Figure 5.1. We have used this framework to report the outcomes against our engagement activities.

In the development of our Draft Plan, we had completed Phases 1 and 2 of our engagement program. Since publishing our Draft Plan, we have also completed Phases 3 and 4 of the engagement program.

This chapter describes our engagement with key stakeholders on the development of our engagement approach, principles, methodology and timeline before engaging on what we would propose for our business in the next AA period.

It also documents and describes the following engagement activities that we have undertaken, and how we have integrated the feedback and outcomes into our Draft and Final Plans:

- Meetings of the South Australian Reference Group (SARG);
- Meetings of the Retailer Reference Group (RRG);
- Three phases of customer workshops with over 150 AGN returning customers from metropolitan and regional South Australia;
- In-depth workshops with culturally and linguistically diverse (CALD) customers in Adelaide, in partnership with Multicultural Communities SA;
- Several "deep dive" workshops into key topics of interest as highlighted by members of our reference groups; and
- One-on-one meetings with individual stakeholders and presentations at their workshops/meetings.

Ongoing, thoughtful and targeted engagement direct with customers across the state and our two stakeholder reference groups, the South Australian Reference Group (SARG) and Retailer Reference Group (RRG), through a series of meetings and workshops, has been critical to the success of this engagement program.

Membership of the SARG reflects the diversity of our customer base, with organisations representing residential and business customers, major gas users, customers facing vulnerability, multicultural communities, the building industry and property developers.

Prior to re-engaging with the SARG at the beginning of this regulatory review period, we considered it prudent to revisit and update the Terms of Reference to ensure that the group was able to reach the best possible outcomes for our stakeholders and customers. We also extended the representation of members to make sure that we were hearing the views of a broad a cross section of South Australians as possible.

The RRG comprises representatives from gas retailers who operate in national markets which we serve, including South Australia.

This chapter also summarises the outcomes of our customer workshops; what we learnt about customer expectations, how we adapted the workshops based on participant feedback, what is important to customers and how we can continue expanding on these foundations as we progress into the next stages of our engagement program.

This chapter demonstrates our dedication to building trust with our stakeholders and customers, that we will go above and beyond to ensure they understand the information we are giving them, and that they can have a say on every topic they have told us is important to them.

It also demonstrates our commitment to our 'no surprises' approach in relation to the proposals we publish in our Final Plan.

Figure 5.1: Our five-stage approach to engagement

Stages 1 to 4 of the Engagement Program are complete

Stage 1
Strategy and research

May – Aug 2024

Purpose
Engaging with stakeholders to better understand customer needs and to consult on our proposed engagement approach.

IAP2 Spectrum
CONSULT/INVOLVE

Engagement Activities
- Meet with key stakeholders
- Publish and consult on a Draft Engagement Plan
- Expand our SA reference group membership
- Agree reference group schedule and role
- Engage with the Retailer Reference Group
- Establish partnership opportunities with customers and stakeholders (e.g ethnic communities)

Key Deliverables
This Stage 1 Final Engagement Report

A report summarising and responding to feedback and including a Final Engagement Plan.

Stage 2
Developing our Draft Plan

Aug 2024 – Feb 2025

Purpose
Running a series of engagement activities designed to inform the development of our Draft Plan.

IAP2 Spectrum
INVOLVE/ COLLABORATE

Engagement Activities
- Series of SA reference group meetings
- Iterative customer workshops across South Australia with key customer segments
- Series of Retailer Reference Group meetings
- Briefings/meetings with key stakeholders (e.g. AER Consumer Challenge Panel)

Key Deliverables
Stage 2 Engagement Findings

Summary tables/report of all feedback from Stage 2 to inform the Draft Plan.

Insight Reports from the Customer Workshops.

Stage 3
Consultation on our Draft Plan

Mar – Apr 2025

Purpose
Focusing on public consultation on our Draft Plan.

IAP2 Spectrum
CONSULT/INVOLVE

Engagement Activities
- Publish and distribute Draft Plan for consultation
- Meetings/ briefings with key stakeholders (e.g. AER Consumer Challenge Panel)
- Customer workshops to consult on Draft Plan
- Combined deep dive workshops for SA Reference Group and Retailer Reference Group meetings

Key Deliverables
Draft Plan

Summary tables/report of all feedback on key areas/issues for further engagement in Stage 4.

Stage 4
Refinement and engagement

Apr – Jul 2025

Purpose
Finalising our plan and incorporating feedback received during consultation on the draft.

IAP2 Spectrum
INFORM/INVOLVE/ CONSULT

Engagement Activities
- Undertake an further engagement as required
- Meetings/briefings with key stakeholders (e.g. AER Consumer Challenge Panel
- Combined deep dive workshops for SA Reference Group meetings and Retailer Reference Group meetings

Key Deliverables
Final Plans to the AER

Submission of Final Plan with supporting customer and stakeholder engagement reports.

Stage 5
Post-Lodgement Engagement

2nd half of 2025

Purpose
Fit for purpose engagement activities designed to address specific feedback from the AER.

Some post-lodgement activities may include separate engagement by networks to address the feedback from the AER on our individual submissions.

5.2 Our engagement approach

In May 2024, we invited the following key stakeholders to collaboratively design and seek input into the development of AGN's engagement strategy, ensuring that participants are aligned on the key objectives for and approach to stakeholder engagement for the Access Arrangement:

- Multicultural Communities Council of SA
- Council of the Ageing SA
- South Australian Federation of Residents and Ratepayers Association Inc
- St Vincent de Paul Society
- Energy Users Association of Australian
- South Australian Council of Social Service
- Energy Consumers Australia
- Ai Group

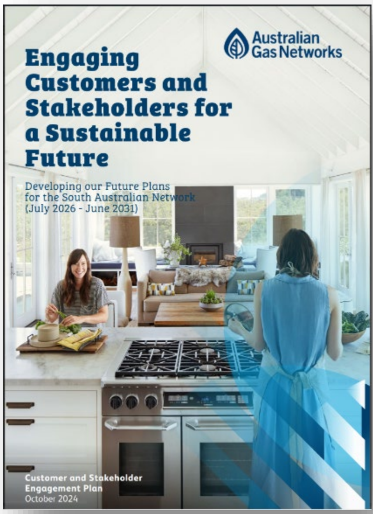
In July 2024 we published our Draft Engagement Plan with an eight-week consultation period. We distributed the Draft Engagement Plan widely and invited key stakeholder groups to provide feedback.

This was an important step in our five-stage engagement approach, as it ensured that we were engaging with relevant stakeholders and customers and giving them the opportunity to provide input into our proposed engagement activities.

To achieve this, we sought feedback on:

- our proposed customer and stakeholder engagement program;
- our proposed engagement principles;
- our proposed engagement topics;
- our proposed engagement activities; and
- our identification of customers and stakeholders.

A summary of feedback we received on our draft Stakeholder Engagement Plan is detailed in Table 5.1. The Final Engagement Plan was published in October 2024 and can be found on our online engagement portal, Gas Matters: (gasmatters.agig.com.au).



5.3 Our customers and stakeholders

We have identified several stakeholder groups with an interest in how we plan, manage and operate our gas distribution network (illustrated in Figure 5.2).

In the early stages of engagement, we consulted with key stakeholders and sought feedback on who should be involved, to ensure that the voices of all relevant stakeholders are heard and considered.

Stakeholders across all of our engagement activities represent a cross-section of our customers, energy retailers, government agencies and other businesses that rely on the delivery of our services.

5.4 Our engagement principles

In collaboration with stakeholders, we adopted a series of engagement principles as shown in Figure 5.3. These principles guide how we engage with our customers and stakeholders.

Figure 5.2: Our customers and stakeholder groups

Table 5.1: Summary of customer and stakeholder feedback on our Engagement Plan

Customer and stakeholder feedback	Our response
Our engagement program	
Stakeholders requested detail on: • the engagement narrative and the reasoning behind why we engage. • how the Engagement Plan interacts with the AER's Better Resets Handbook.	Further detail on the Engagement Plan narrative and reference to the AER's Better Reset Handbook was included in the Final Engagement Plan.
Our engagement principles	
• Stakeholders expressed support for our engagement principles. • One stakeholder suggested we make it clear that under the engagement principle 'clear, accurate and timely communication' the information we provide is also understandable.	We incorporated the word 'understandable' into the "Clear, Accurate and Timely Communication."
Our customers and stakeholders	
• Stakeholders suggested we explicitly mention First Nations people, renters and people experiencing vulnerable circumstances as customers in the Engagement Plan.	We updated the 'residential customers and community' section to explicitly include First Nations people, renters and people experiencing vulnerable circumstances. Indigenous Australians: We strongly encourage members from local Indigenous groups to participate in any other engagement activities that are of interest to them, such as the customer workshops. If any specific issues affecting local indigenous groups arise as we prepare our submission, we will reach out to discuss these.
Our engagement activities	
• Stakeholders requested details on the digital opportunities for engagement with customers and stakeholders. • Stakeholders suggested expanding engagement activities to include an additional forum to discuss key regulatory issues at a more in-depth level.	We included more detail on digital opportunities and on additional engagement activities to discuss key regulatory issues.

Figure 5.3: Engagement principles

Our Engagement Principles

Genuine and Committed

We listen and respond to the needs of our customers and stakeholders, driving a culture of delivering value for our customers

Engagement is led from the top

Stakeholder engagement is embedded in our business planning

We look to continually improve

Transparent

We clearly identify and explain the role of customers and stakeholders in the engagement process, and consult with customers and stakeholders on information and feedback processes

Publication and consultation of our proposed engagement approach

Online public reporting

We publish and consult on our reports

We report how we used stakeholder insights to inform plan

Clear, Accurate and Timely Communication

We provide information that is clear and understandable, accurate, relevant and timely

Accessible and Inclusive

We involve customers and stakeholders on an ongoing basis in a meaningful way, to ensure that our plans deliver for our customers

Stakeholder meetings

Ensuring engagement is accessible to all stakeholders, regardless of age or cultural, linguistic or socioeconomic background

Measurable

We measure the success, or otherwise, of our engagement activities

Seek stakeholder feedback at all key stages of our engagement

Report on feedback

Identify ways to improve our approach

Integrated

We will be responsive by integrating customer and stakeholder feedback into all aspects of this work

Clear evidence that we have listened and responded to customer and stakeholder feedback in our plans

5.5 Key topics for engagement

Our engagement program covers a broad range of often complex topics. In developing the list of topics, we asked our stakeholders and customers what was most important to them. We have been guided by our customers and stakeholders on where to focus our engagement activities.

A key part of our engagement program is our customers' and stakeholders' keen interest in discussions around the future of gas. Our South Australian stakeholders were keen to learn more about our plans in South Australia for decarbonisation of gas and the future of gas more broadly, including within the national context.

In particular, stakeholders highlighted their interest in:

- how decisions we make today will impact customers in the future;
- what renewable gas could mean for customers in the energy transition (e.g. in terms of appliances, transition costs); and
- the potential role gas will play in a low carbon future.

5.6 Engagement activities and feedback

5.6.1 Customer engagement

Engaging directly with customers has been critical to ensure that we align our plans and proposals with customers' needs and expectations. We pride ourselves on putting customers at the heart of everything we do, and believe that every decision we make should benefit current and future gas customers.

<u>Customer workshop methodology</u>

Our customer workshops were run in three phases with the same group of customers, allowing iterative engagement as we developed and refined our plans.

We have completed three phases of workshops with customers across South Australia – in August/September 2024, October/November 2024, and March/April 2025. Feedback obtained from the 135 recurring customers who attended across a total 23 workshops has been used to shape our plans and proposals.

Repeat engagement with the same group of customers enables us to:

- build customer knowledge over time to allow customers to make informed decisions;
- test and validate our ideas in response to customer feedback as we develop proposals; and
- prioritise and explore issues in more detail in response to customer feedback.

We were pleased to be able to hold most of our workshops with customers face-to-face, to allow opportunities for organic discussions, which in turn further contributed to the development of our plan.

Participants were recruited through a specialist third party provider, selected to ensure the group was representative of a broad cross section of the community.

We also partnered with Multicultural Communities Council of SA (MCCSA) in hosting dedicated workshops with CALD customers in metropolitan Adelaide.

Customer workshops were facilitated by a third party (KPMG) to independently capture and document customer feedback.

We used a range of tools to ensure that workshops were engaging and interesting, including presentations from subject matter experts, interactive polling/surveying tools and the opportunity for customers to ask questions throughout the 90-minute workshops.

During the workshops that were held online via MS Teams, the chat function was constantly monitored so participants felt like they could type their question/feedback without interrupting the presentation. Participants were encouraged to turn their microphones and cameras on, and use the 'raise hand' function to alert the facilitator that they had a question to ask or comment to make.

During Phase 1, KPMG facilitated the use of the visual online collaboration tool 'Mural' to ensure that interactive activities were as engaging for online participants as they were in the face-to-face workshops. During Phase 3, KPMG facilitated a 'word cloud' activity to see what customers remembered about renewable gas.

<u>Phase 1 Customer Workshops:</u>

181 customers attended Phase 1 of our customer workshops, representing metropolitan, regional, residential and small business customers.

Phase 1 workshops were designed to align to our engagement principles and objectives, including listening to customer views on a range of topics, providing relevant information and committing to integrating customer feedback into our Plan.

To facilitate genuine conversation where everyone had the opportunity to have their say, the Phase 1 workshops were designed and delivered based on the following four engagement objectives:

- Build engagement: ensure participants felt welcomed, valued and were eager to return to future workshops;
- Educate: provide a sound understanding of our business, role in the gas network, regulatory oversight and demonstrate the importance of good engagement to our decision-making;
- Explore: genuinely engage with, listen to and understand what is important to participants, what they value, their preferences and what their interest areas are; and
- Prepare: understand which topics participants are interested in focusing on.

During each 90-minute workshop, AGN subject matter experts were in attendance to present and respond to questions directly from customers. We conducted interactive activities to keep the workshops interesting.

We asked customers a series of questions relating to reliability, public safety, customer service, affordability, the future of the gas network and innovation.

We invited stakeholders to provide feedback on the most important aspects of our service and issues we should be considering in our future planning. This enabled us to focus on these topics in subsequent engagement activities in Phase 2.

During Phase 1, customers identified the following key topics as issues of importance for consideration in the development of our plans:

- Price and affordability;
- Customer service and customer experience;
- Reliability of supply;
- Public safety;
- Future of gas; and
- Regulatory building blocks.

See Table 5.2 for a detailed list of these topics for engagement.

Table 5.2: Key topics for engagement

Key topics
Price and affordability of gas bills
• Price paths • Intergenerational equity
Customer service and experience
• Services for customers in vulnerable circumstances
Reliability of supply
Public safety
Future of gas
• Renewable gas opportunities • Government policy impacts • Future Energy scenarios • Customer transition/impacts of renewable gas blending • Demand impacts • Long term planning (beyond five-year plan)
Regulatory building blocks
• Pipeline services • Setting our capital base • Depreciation • Demand forecasting • Our capital and operation expenditure proposals over the next period
Terms and conditions

In Phase 1, customers told us that:

- Price and affordability were their top priority:

  "Affordability means having a stable and reasonable gas price that fits our budget."

  "Energy is an essential service and needs to be cost effective."

- They are highly satisfied with the reliability of their gas supply:

  "Gas reliability is important to me, home and business for washing, cooking and mechanical repairs."

- They expect efficient resolution to an issue and prefer to talk to someone directly:

  "Great interaction would include multiple options for contact – email/phone/chat on website. And timely response and action."

- Renewable energy is important to them, but affordability is a key consideration:

  "Clean energy is important as long as it's reliable and affordable."

- They are interested in the future of gas and have a strong desire to explore it further during the engagement program:

  "What are the plans to use biogas and where?"

  "Is it true that Victoria is removing/abolishing [gas] in new houses?"

  "What does the future of natural gas look like in South Australia?"

<u>Phase 2 Customer Workshops:</u>

Of the 181 customers that attended our Phase 1 workshops, 153 returned for Phase 2, representing an 85% return rate. See Table 5.3 for details.

In Phase 2 workshops we looked to further explore issues of importance and gain customer input into the development of our plans.

We designed these workshops to extend and build on the foundational knowledge customers had gained in Phase 1, equipping customers with enough information to enable them to genuinely engage and provide feedback on topics aligned to their interests.

The objectives of our Phase 2 workshops were to:

- Maintain engagement: continue to ensure that participants felt welcome, valued and were eager to return to the final phase of engagement.
- Test and align: build on the knowledge of customers' priority areas by starting to test potential investments and decisions that align with customer expectations and priorities. Commit to seeking input and feedback from customers to ensure shared value is created through the decision-making process.
- Foster informed decision-making: based on knowing what is important to customers, provide more detailed information on key priorities and interest areas, and address questions to ensure customers can provide informed input and feedback during the workshops.
- Validate: confirm key feedback and insights with participants in a way that reassures participants that they have been heard and listened to.

Phase 2 workshops were generally 90 minutes in duration and included opportunities for open discussion with AGN subject matter experts.

Participants were asked to provide feedback and ask questions at the end of each topic, as well as a 2-minute paper at the end of the workshop asking participants:

- Have we covered all the issues and topics that are important to you?
- What else would you like to know in future sessions?

The key insights obtained from the Phase 2 workshops remained very similar to those obtained from Phase 1. Summarised in KPMG's Report:

- Customers were satisfied with our proposal to maintain stable prices and customer service levels (including our Priority Services Program for supporting vulnerable customers):

"What factors are being taken into account on prices being stable in the next five years?"

- Customers strongly support our approach to maintaining gas safety and reliability:

"Knowing AGN is staying on top of maintenance is reassuring."

"I feel highly confident that the reliability will be maintained through this approach."

- Customers are interested in learning more about our plans to grow our gas distribution network:

"Will new infrastructure be able to use 100% renewable [gas] and will old meters need to be upgraded?"

"What are the challenges for regional development of new communities like the large housing developments at Gifford Hill (near Murray Bridge)?"

- Customers want to better understand the network's proposed shift to a renewable energy future and the personal impacts of the transition:

"How will hydrogen be delivered alongside natural gas?"

During Phase 2 workshops we presented customers with information about our early price forecasts for the 2026-31 Access Arrangement period. In line with customer sentiment from Phase 1, we informed customers that we were proposing stable prices based on their feedback that steady and stable pricing was the most important factor.

Table 5.3: Phase 1 & 2 Workshop Attendance

Location	Customer Segment	Phase 1 Workshop Attendance	Phase 2 Workshop Attendance	Phase 3 Workshop Attendance
Adelaide metro	Residential	30	30	29
Adelaide south	Business	23	19	16
Adelaide north	Residential	23	26	18
Port Pirie & Whyalla (online)	Residential and business	19	13	15
Barossa, Gawler & surrounds	Residential and business	16	12	12
Mt Gambier	Residential and business	20	18	25
CALD	CALD customers	25	20	20
Additional online workshop	Residential	25	15	-
Total		**181**	**153**	**135**

We presented customers with an infographic detailing how we intend to spend every dollar of the opex and capex over the 5-year period.

<u>Phase 3 Customer Workshops</u>

During Phase 3, 135 customers returned to hear from us about our Draft Plan, give their feedback and ask questions. At these workshops we built more on the information we had already learned from our customers in the previous two phases, and focussed on the key topics that we knew were most important to them:

- Price and affordability
- Public safety
- Network reliability
- The future of gas
- Maintaining and growing our network
- Customer experience and services
- Depreciation

The key outcome from these workshops was that our customers were well informed about our Draft Plan, and that their feedback would enable us to refine our proposals before finalising our Final Plan.

Through these workshops we learnt that:

- Customers strongly support our Draft Plans across key priority areas, being price & affordability, maintaining & growing the network and public safety & reliability:

"The Draft Plan looks really promising and appears feedback is being implemented."

- Customers were given the opportunity to learn more about our renewable gas plans, and continued to indicate that they're interested to know more:

  59% of customers indicated they would like to learn more about renewable gas and future development opportunities like HyP Adelaide.

- *Most* customers understand enough about depreciation and support our approach to consult further if the depreciation figure equates to more than $40 per customer per year:

  "As long as the overall bill doesn't change (significantly) I don't feel the need to know if the depreciation component of my bill increases."

Noting that price and affordability had been consistently raised as the top priority for customers, we sought feedback from participants on two key price-related proposals during Phase 3 workshops:

1. Price structure – looking at flattening prices and what impact this has on bills, and
2. Charge for service abolishments.

Price structure

We asked customers whether they supported our approach to charging based on a declining block tariff structure or whether they would prefer us investigate the option for flat pricing. The responses we received from customers showed that the majority preferred our declining block tariff structure opposed to a flat tariff structure. We noted that a flat structure *could* be a step towards meeting national emissions reduction targets, but participants seemed to prefer choosing the option that would have the least impact on their household budgets.

"I like option 2 [flatter declining block tariff] in that it will not encourage excessive gas use but am concerned the cost increase will fall on those who can least afford it."

Service abolishments

We asked customers for their opinion on our policy for permanent disconnections of gas services. We explained to customers that we currently only charge for the cost of removing the meter, not the costs associated with digging up the infrastructure and completely disconnecting the service. Some customers found it surprising that the remainder of the customer base therefore pays for the cost to do this work. However, once we explained our reasons for this approach (the key being safety purposes), customers understood and some expressed concern that if we changed our policy and started charging more for a service abolishment, some customers would choose to avoid the fee and opt to leave an unused service connected to our network. 49% of customers preferred us to maintain our current approach, and 25% of customers suggested that applicants should pay *towards* the overall cost, with the remainder distributed across the customer base.

"It would depend on the reason for abolishment. Perhaps different prices for different reasons, e.g. development of a property for units or for safety reasons."

<u>Summary of workshops</u>

Full KPMG reports on the Phase 1, 2 and 3 workshops are available on our online engagement portal, Gas Matters (gasmatters.agig.com.au).

A summary of customer feedback and how we responded is shown in Table 5.4.

We set ourselves a target to achieve 80% satisfaction with the way in which we engaged with our customers during these workshops. The results of this feedback are shown in Table 5.5, confirming we have exceeded that target. We asked customers at the end of each workshop to rate the workshop as a whole, so that we could learn from their feedback and make the next interaction more positive (see Table 5.6).

5.6.2 Stakeholders, meetings and forums

At the commencement of this engagement program, we re-established our South Australian Reference Group (SARG) and Retailer Reference Group (RRG). As these two groups had different objectives and views, we initially held the meetings separately to ensure we could focus on their different priorities appropriately. However, at the beginning of 2025 we combined the two groups to ensure full transparency and sharing of ideas between different stakeholders.

In 2024, the SARG met four times and the RRG met three times. In 2025, the combined group met six times.

<u>South Australian Reference Group (SARG)</u>

The SARG is made up of industry representatives and stakeholder advocates who represent a wide range of South Australian gas end-users, including customers in vulnerable circumstances, culturally and linguistically diverse customers, businesses of varying sizes and industries, social service organisations and property developers:

- South Australian Federation of Residents and Ratepayers Association Inc
- St Vincent de Paul Society
- Energy Users Association of Australia
- SA Business Chamber
- Ai Group
- Urban Development Industry Association SA
- Multicultural Communities Council of SA
- South Australian Council of Social Services
- SA Financial Counsellors Association
- Energy Consumers Australia
- Australian Energy Council
- Renewable Gas Alliance
- Master Plumbers Association
- Property Council of Australia (SA)

The role of the SARG is to:

- provide input and feedback to inform the development of our plans, ensuring they are capable of acceptance by customers and stakeholders upon submission to the Australian Energy Regulator;
- inform and shape our engagement activities to ensure we deliver best practice, fit for purpose engagement;
- advocate in the interests of constituents to ensure our plans deliver value for all customers; and
- challenge our businesses to deliver the best possible outcomes for current and future customers.

The SARG has had input into the design of all our engagement activities. Some members attended and observed our Phase 1 and 2 customer workshops, and we presented members with key insights from customer workshops at our meetings.

The SARG met 10 times between August 2024 and June 2025 in the development of our Draft Plan, and as we refined our proposals in the development of this Final Plan. A number of representatives also attended several online 'deep dive' workshops on some of our proposals that they requested more information on.

SARG members have consistently showed interest in understanding our future plans, and what this would mean for customers in the context of price. They were also focussed on ensuring that our proposals are cost efficient while delivering for current and future customers. Given this interest in these topics, we provided early price modelling to members at our meeting in October 2024. This early presentation of our prices is consistent with our commitment to our 'no surprises' approach to engagement.

Retailer Reference Group (RRG)

The RRG is a mechanism used to formally engage with gas retailers, who play a major role in customer experiences with our gas networks.

Five of the six gas retailers that operate in South Australia are represented on our RRG, including:

- AGL
- Alinta
- Energy Australia
- Origin Energy
- Red Energy
- Momentum (not in SA)

Through the RRG, retailers were interested in discussing some specific elements of our proposals, including reference services, terms and conditions, prices, Heating Value of hydrogen blend gas and any new program that might impact their operations (i.e. Priority Service Program).

The RRG met nine times between May 2024 and June 2025, including face-to-face and online meetings. A number of representatives also attended several online 'deep dive' workshops on some of our proposals that they requested more information on.

RRG members have provided feedback and insights into how our preliminary proposals may impact their business and their customers.

A summary of key topics and information presented to the SARG and RRG is listed in Table 5.7.

SARG Review Panel

In March 2025, we supported the establishment of the 'SARG Review Panel' as guided by the best practice engagement objectives outlined in the AER's Better Resets Handbook.

Under the Terms of Reference, which was developed in consultation with SARG members, the SARG Review Panel's role is to provide independent and constructive feedback and challenge based on their expertise and insight during the development of AGN SA's 2026-31 regulatory proposal which include a review of:

- AGN's engagement program and associated activities, and
- AGN's regulatory proposal (Draft and Final Plans).

The members of this Panel were to conduct these reviews on behalf of the SARG collective, not on behalf of their individual memberships.

Three SARG members nominated for a role on this Panel, which met six times (with AGN attendance) between 2 April and 26 May 2025. The SARG Review Panel submitted their report on our Draft Plan, and we committed to working collaboratively with them on the matters they highlighted the most concern with; our Future of Gas narrative and depreciation. We accepted the feedback from the SARG Review Panel, including their suggestion to delve deeper into the narrative around where we see our business in 2050, and how we plan to get there. As a result of the Panel's feedback, we have included an attachment detailing our strategy for achieving our net zero by 2050 ambition (Attachment 6.4 Energy Transition), as well as more detailed information on our depreciation approach and the way we model depreciation (see chapter 6 and Attachment 6.1). We have also added the 'Context of our Plan' section to address the Panel's request for more narrative.

Consumer Challenge Panel

The AER's Consumer Challenge Panel (CCP) was announced in November 2024. According to the AER's website, the objective of the CCP is to:

- advise the AER on whether the long-term interests of consumers are being appropriately considered in regulatory proposals and the AER's decision making
- provide an assessment of networks' consumer engagement, including the extent to which proposals reflect consumer preferences.

Since its formation, the CCP has observed the majority of our SARG and RRG meetings and deep dives. They also observed our online Phase 3 customer workshop with customers from Port Pirie and Whyalla, and we were able to facilitate their online access to observe our face-to-face workshop with metropolitan Adelaide customers. One member also attended our HyP SA tour in December 2024.

5.7 Developing our Final Plan

All feedback from SARG and RRG meetings, together with feedback from customer workshops was captured and used to shape our Draft Plan.

Our extensive customer and stakeholder engagement program that followed the Draft Plan has proven our commitment to learning what factors are important to all end-users, and ensuring that our Plans align to achieve them.

Through the refinement of our Draft Plan to Final Plan, our intentions have been clear – to ensure that we have been completely transparent to allow stakeholders and customers to feel satisfied that our plans are in the best interests of current and future customers.

Orbviz: an innovative way to engage with our customers and stakeholders on our Plans

In strengthening our program of engagement activities and to promote breadth and depth of engagement (a key principle under the AER's *Better Resets Handbook*), we partnered with Orbviz to design a digital and interactive version of the Draft Plan.

The tool presented the Draft Plan information in an engaging and interactive way, allowing customers and stakeholders to focus on the aspects of the Draft Plan that interested them, and to give them the opportunity to provide feedback.

Orbviz did not replace the Draft Plan documents but rather complemented it – providing a snapshot summary of our proposals, with detailed explanation and information in the Draft Plan itself.

We collaborated with key stakeholders to design the platform to ensure that it meets the needs of different customer and stakeholder groups, and we introduced it to customers during Phase 3 workshops as a way for them to be able to refer back to the information they had learnt from us and delve deeper into the data in their own time, should they choose to do so.

We will be presenting the data from within this Final Plan in Orbviz, and will use it as a way to engage with customers and stakeholder as we enter the next phase of engagement following the draft decision from the AER.

Table 5.4: Customer feedback on topics presented

Theme	Engagement activity	Key insights and results
	Phase 1 customer workshops	
Price and affordability	Customers were given an overview on our pricing model, and were introduced to our Priority Services Program. This followed discussion and questions around what affordability means to customers, and what a great interaction with us would involve.	• The majority of customers across all eight workshops ranked price and affordability as the number one priority. • Customers equate affordability with steady and stable prices. • Affordability means not having to make lifestyle trade-offs, such as being able to keep warm over winter.
	Phase 2 customer workshops	
	We presented to customers a break down on how residential bills are constructed, and showed how we intend to spend every dollar in the context of operating and capital expenditure. Customers were presented with an early forecast average residential distribution charge of $628 from 1 July 2026, subject to variables and customer preferences. We presented to customers our capital and operating expenditure proposals.	• Customers were comfortable that we were not proposing increases to pricing, but were keen to understand our proposal in more detail. • Customers expressed a high level of support for our proposed pricing approach to maintaining current safety and reliability levels. • Customers were satisfied with our proposal to continue our Priority Services Program which supports customers in vulnerable circumstances.
	Phase 3 customer workshops	
	We presented customers with an overview of the key proposals in our Draft Plan, including maintaining stable prices over the 5-year period and providing customers with a 0.9% price cut in year one. We asked customers their preference for our tariff structure, and whether they thought it was appropriate for us to consider charging a fee to abolish a customer's gas service.	• The majority of customers indicated that they supported AGN's declining block tariff structure, with 23% of customers indicating they were happy with the current approach and 49% of customers showing their preference for our proposal to slightly flatten the tariffs. 28% of customers would like AGN to consider a flatter price structure. • Customers were generally unaware that AGN did not charge a fee for abolishing a gas service. Given the safety reasons associated with this, only 13% of customers thought an applicant should pay the full cost of a service abolishment. 13% of customers thought a fee of around $500 was appropriate, 25% of customers suggested a fee of between $100-250 and 49% of customers were satisfied that the current approach is the most reasonable.

Table 5.4: Customer feedback on topics presented (continued)

<table>
<tr><th>Theme</th><th>Engagement activity</th><th>Key insights and results</th></tr>
<tr><td rowspan="7">Safety and reliability</td><td colspan="2">Phase 1 customer workshops</td></tr>
<tr><td>We explained what reliability and safety means to us, and asked questions relation to their views on their importance:
• Why is gas reliability important for you or your business?
• How satisfied are you with the current reliability of your gas supply? Why and how could it be better?</td><td>• Customers place a great deal of importance on uninterrupted supply of gas to their homes and businesses.
• Reliability of supply was ranked as customers second highest priority.
• Customers are satisfied with the current levels of gas reliability.
• Many customers have never experienced a disruption to their gas supply.</td></tr>
<tr><td colspan="2">Phase 2 customer workshops</td></tr>
<tr><td>We presented our proposal to maintain current levels of reliability and safety over the next five-year period, which is forecast to cost 35c in every dollar of a customer’s bill.
Customers were asked:
• “Are you happy with our proposed approach to maintaining gas safety? Why or why not?”
• “Are you happy with our proposed approach to maintaining gas reliability? Why or why not?”</td><td>• 97% of customers stated they were satisfied with our approach to maintaining service reliability.
• Customers have a high degree of confidence in our public safety and reliability track record and expect this to continue over the next five-year period.
• Across the eight workshops, 11 customers expressed the need for more information on our approach to maintaining gas reliability, specifically around:
  ◦ The reliability of gas once more hydrogen is integrated, and
  ◦ Whether or not AGN will be replacing pipelines in SA based on the age of the infrastructure</td></tr>
<tr><td colspan="2">Phase 3 customer workshops</td></tr>
<tr><td>We showed customers the main areas that we proposed to invest in to ensure we are sustaining our safety and reliability track record:
• Medium risk multi-user service renewal,
• Replacement of old steel pipes reducing unaccounted for gas in the network, and
• Ongoing pipe integrity dig ups

We then asked customers if we had appropriately understood and applied what is important to them in relation to their expectation that we maintain high levels of public safety and gas distribution reliability.</td><td>• 100% of customers were satisfied with our proposals aligning to our commitment to maintain public safety and reliability.</td></tr>
</table>

Table 5.4: Customer feedback on topics presented (continued)

Theme	Engagement activity	Key insights and results
	Phase 1 customer workshops	
Customer experience	Customers were asked what they believed a great interaction with us looked like.	• Customers expect efficient resolution to an issue and prefer to talk to someone directly. • Customer experience was not rated a high priority for further discussion (compared to the other topics), but customers were clear that they expect good communication and simple service that is resolution-focused. • Customers often prefer interacting with real people, and having the option for online chat and SMS.
	Phase 2 customer workshops	
	We presented to customers our proposed budget breakdown across key customer service areas, including our Priority Services Program which supports our customers experiencing vulnerability. We discussed our Customer Service Centre and other customer service areas such as public safety, network growth and network operations.	• Customers were satisfied with our proposal to continue our Priority Services Program which supports customers in vulnerable circumstances. • Some customers asked for more information on what else the 20c allocated spend to "Customer Service" would entail and after receiving more information was comfortable with proposal.
	Phase 3 customer workshops	
	We shared with customers how we proposed to spend $218 million to maintain the high standard of service that customers value and expect: • Priority Services Program for customers experiencing vulnerability • Ongoing enhancements to customer relationship management system • Continued maintenance for local onshore call centres • Investment into smart digital meters	• 98% of customers were satisfied with our proposals aligning to our commitment to delivering high levels of customer service.

Table 5.4: Customer feedback on topics presented (continued)

Theme	Engagement activity	Key insights and results
	Phase 1 customer workshops	

Renewable energy and the future of gas	We explained to customers about our renewable energy initiatives, followed by a discussion and questions in relation to how important the supply of renewable energy was to customers.
	Customers were asked whether the supply of renewable energy was important to them.
	Customers were also asked what they would like to know more about in terms of renewable gas.
		• Customers stated that our commitment to supplying cleaner energy was important, but affordability for customers is a key consideration.
		• Customers asked:
		  • "Will the price of gas be affordable?"
		  • "Would there be an opt in for biogas or green energy usage and would there be a significant cost to the end user?"
		  • "What is the overall environmental impact of switching gas from natural to renewable when looking at the climate crisis on the whole?"
		• Customers expressed curiosity and interested in the shift from natural gas to renewable gas.
		• Customers wanted to know more about our renewable gas initiatives, cost of renewable gas and appliance compatibility.

	Phase 2 customer workshops	
	We focussed on sharing information and educating customers on the future of gas, to allow them the opportunity to genuinely engage on options. We also shared in-depth information on regulation and competition in the market and how this impacts our business in terms of depreciation. We presented a placeholder figure on customer bills.	• Customer feedback centred on seeking more information about our role in transitioning to a new energy future, as well as the direct personal impact the shift to renewable energy will have. • Customers noted they were unaware of our hydrogen project until attending these workshops. • Customers wanted to know more about the cost of renewable gas, and whether there would be incentive for customers using hydrogen as they are contributing to a positive climate change initiative. • Some customers advised the placeholder for depreciation was minimal, others wanted to understand in more detail the impacts.
	Phase 3 customer workshops	
	We asked customers to participate in an activity to see what they remembered from previous workshops about renewable gas. As customers had told us throughout Phase 1 and 2 that they are interested in learning more about renewable gas, we took the time to share information with them on our proposed HyP Adelaide project. We also shared significant detail on our net zero emissions goals.	• Customers continue to be interested in our plans and want to be kept informed as projects progress. • Customers were eager to know more about how renewable gas blends to their home would impact them and whether they will need new pipes and new appliances.

Table 5.5: Customer response to engagement metrics

Engagement metrics	AGN target (%)	Phase 1 result (%)	Phase 2 result (%)	Phase 3 result (%)
The workshop information provided was clear, relevant and accurate	+80%	**96%**	**98%**	**93%**
I felt genuinely listened to and heard	+80%	**93%**	**95%**	**92%**
There was an opportunity to have your say	+80%	**95%**	**95%**	**93%**
The workshop content was delivered in an accessible way	+80%	**93%**	**97%**	**92%**
The workshop activities were engaging and educational	+80%	**97%**	**89%**	**92%**
The workshop venue and time was appropriate	+80%	**97%**	**95%**	**93%**
The delivery of the overall workshop was of high standard	+80%	**100%**	**97%**	**93%**

Table 5.6: Tailoring workshops based on customer feedback

Phase 1 feedback	How we tailored for Phase 2
Reduce paper/printing: Some participants commented that there was too much use of paper throughout the workshop, requesting digital options to provide feedback and engage in activities.	In Phase 2, we introduced QR codes that enabled participants to share their feedback and participate in workshop activities through digital worksheets. This improved the user experience for participants as there was a significant uptake in participants utilising the QR codes.
Question time: Some participants said they really enjoyed the open question time for discussion in Phase 1, requesting that there was more of this throughout the workshop.	In Phase 2, we ensured there were additional opportunities for open question time with AGN subject matter experts and the executive team.
Logistics: Some comments from participants expressed dissatisfaction on the location of the Adelaide North venue, noting they would prefer a venue that was more accessible.	The location of the Adelaide North workshop was changed in Phase 2 to enhance accessibility and inclusivity for participants, in line with the identified engagement objectives.

We maintained flexibility throughout the phases of the workshops and were committed to making real-time updates to the facilitation of our workshops in accordance with participant feedback. For example, slight visual changes were made to 'The Future of gas in the energy transition' content based on feedback from the first three workshops of Phase 2 to ensure maximum understanding and engagement from customers.

In Phase 3, we determined it was necessary to make changes to the information we were presenting after customers in our Mt Gambier workshop advised the graphs showing potential price paths was difficult to understand. Given that customer preference has little influence over price paths (the AER makes the final decision), we removed the graphs entirely to avoid confusion in future workshops and focussed more on tariff structures.

Our customer and stakeholder process
2024 - 2025

Australian Gas Networks

Key

SARG
South Australian Reference Group.

RRG
Retailer Reference Group

2024

Stage 1
Strategy and Research

May - August
We engaged with our SARG members to better understand customer needs and to consult on our proposed engagement approach.

July
We published our Draft Engagement Plan for consultation. We asked stakeholders including our SARG, RRG, Government agencies and customers if our proposed engagement plan was appropriate for our customers and stakeholders.

Stage 2
Developing our Draft Plan

8 August 2024
SARG and RRG meetings

August – September
We held the first phase of our workshops with over 180 customers across South Australia.

Customers at a workshop in Adelaide's South

13 September
SARG and RRG meetings

October
We published our Final Engagement Plan, taking into account feedback and input from stakeholders.

October – November
We held the second phase of our workshops with over 150 customers across South Australia.

22 October
SARG meeting

November
Appointment of CCP

2 December
SARG meeting (including site visit to HyP SA)

6 December
RRG meeting

SARG members touring HyP SA

2025

Stage 3
Consultation on our Draft Plan

27 February
Combined SARG and RRG meeting

SARG & RRG members participating in an online meeting

28 March
We published our Draft Plan and commenced the consultation process with stakeholders and customers.

31 March
We launched Orbviz – a digital, interactive web platform that allows customers and stakeholders to engage in our Draft Plan in a way they never have been able to before.

Stage 4
Refinement and Engagement

March
We supported the establishment of the 'SARG Review Panel' to provide independent feedback and challenge on our engagement activities and our regulatory proposals.

March – April
We held the third phase of our workshops with over 150 customers across South Australia.

April
We surveyed our Major Users to understand their future gas needs for our demand forecasting.

April – May
We held a series of meetings with SARG and RRG members to dive deeper into the key topics they identified that they wanted more information on from our Draft Plan, including the Future of Gas, depreciation, tariff structures, capex and opex.

April – May
We met with the SARG Review Panel to work collaboratively on our Future of Gas narrative and our approach to depreciation, the two main topics that were highlighted in their submission into our Draft Plan.

May
RRG Deep Dive to discuss draft General Terms and Conditions

5 & 18 June
Combined SARG and RRG meeting to address final queries from stakeholders and discuss changes from Draft Plan to Final Plan

5.9 Stage 3: Consultation on our Draft Plan

The release of our Draft Plan meant we entered Stage 3 of our five-stage approach (March – May 2025), and we began consulting widely with customers and stakeholders on our proposals.

A series of consultation questions were included within the Draft Plan document, on our online portal Gas Matters (gasmatters.agig.com.au), and on Orbviz (see below).

To support stage 3 engagement we:

- published our Draft Plan online for a four week period for public consultation;
- continued to engage with customers in the third phase of our workshops;
- continued holding meetings with the SARG and RRG; and
- offered briefings and one on one meetings with stakeholders.

These activities supported engaging on the details of our plans, including in the context of our broader business plans.

We received four formal submissions from stakeholders on our Draft Plan:

- Energy and Water Ombudsman SA
- South Australian Federation of Residential Ratepayers Association
- SARG Review Panel
- South Australian Council of Social Services

AGL and Energy Australia also provided comments on our Plan.

5.10 Summary Feedback and Our Response

We have undertaken a range of engagement activities to support the development of our Draft Plan, and refinement of our Final Plan.

All customer and stakeholder feedback and how we have responded in this Draft Plan is shown in Table 5.4.

5.11 Next steps

Once we have submitted our Final Plan to the AER, we will publish it online, provide access to our stakeholders and customers and advertise via social media.

Once we receive the Draft Decision from the AER, we will consider any required post-lodgement engagement and consultation.

We will offer meetings and briefings with our broad range of stakeholders on our Final Plan, to ensure we address any unanswered questions they may have.

We will encourage stakeholders and customers to interact with the Orbviz platform.

A range of engagement activities which will support our Final Plan will likely include a further phase of customer workshops and continued SARG and RRG meetings.

Customer feedback:

Phase 1

- ✓ "Clear and well spoken, excellent engagement. I felt heard verbally and with the post it notes. Great engagement."
- ✓ "Well organised and run workshop. The hosts and speakers were very informative. The post-it notes were a great idea for sharing thoughts and questions. Very engaging workshop."
- ✓ "I learnt about AGN and why they want to improve. I valued various viewpoints that were present. Having reps at the table was very useful."
- ✓ "Very informative and clear information given. Great staff from AGN."

Phase 2:

- ✓ "The workshop ran very smoothly and was very informative."
- ✓ "The knowledge of the presenters and their delivery was able to be understood. Not too much jargon."
- ✓ "Level of information was in depth and very informative. I valued the foresight in using renewables and hydrogen in particular."
- ✓ "Staff were very interested in getting feedback. Loved their enthusiasm, it made me feel like providing more feedback."
- ✓ "The information and slides were informative and clear. The presenters were clear and concise and having multiple presenters helped break up the session."

Phase 3:

- ✓ "[I enjoyed..] the discussions about how our views have been accounted for in the Draft Plan."
- ✓ "Very much enjoyed participating, and keeping abreast of developing technology and the thorough ways it was comprehensively explained in laymen terms."
- ✓ "I enjoyed the process of all the different stages from beginning to end."
- ✓ "[I enjoyed..] the opportunity to participate in the decision making."

What could be improved for next time?

- ✓ "Recap information beforehand."
- ✓ "Some slides could be simplified for ease of viewing."

Table 5.7: Summary of SARG and RRG meetings

Meeting	Key discussions
Engagement strategy co-design workshop (May 2024)	KPMG facilitated a workshop with key stakeholders and AGN representatives collaboratively design and seek input into the development of AGN's strategy, ensuring that participants are aligned on the key objectives for and approach to stakeholder engagement for the AA.
RRG Meeting #1 and Feedback session Key Stakeholders and Feedback session (May 2024)	• Draft Reference Service Proposal • Form of Revenue Control • Tariff Structure • Stakeholder feedback
SARG Meeting #1 (August 2024)	• Business overview • Future business plans • Role of the SARG • Draft engagement plan for consultation
RRG Meeting #2 (August 2024)	• Access Arrangement overview • Draft Reference Service Proposal • Forms of revenue control • Tariff structure
SARG Meeting #2 (September 2024)	• Stakeholder engagement update • Regulatory building blocks • Capex forecasting • Accelerated depreciation
RRG Meeting #3 (September 2024)	• Overview of what we have delivered and future plans • Draft engagement plan
SARG Meeting #3 (October 2024)	• Stakeholder engagement update • Orbviz presentation • Indication of preliminary early modelling • Preliminary work on depreciation
RRG Meeting #4 (October 2024)	• Stakeholder engagement update • Orbviz presentation • Indication of preliminary early modelling • Preliminary work on depreciation • Capex, opex and demand forecasting
Deep Dive Workshop (November 2024)	• Gas policy in South Australia • AGIG's low carbon vision • Future of gas plans
SARG Meeting #4 (December 2024)	• Tour of Hydrogen Park South Australia (Tonsley) • Stakeholder engagement update • Reference service proposal • Demand history and forecasting • Independent review into the SARG • Prices for the next AA period and preliminary modelling • AER's release of its Final Decision on our Reference Service Proposal
RRG Meeting #5 (December 2024)	• Heating values briefing • Reference Service Proposal update • Demand forecasting • Stakeholder engagement update

Table 5.7: Summary of SARG and RRG meetings (continued)

Meeting	Key discussions
SARG/RRG Online Workshop (February 2025)	• Orbviz demo • Sub-committee into review of SARG

SARG/RRG Meeting #1 (February 2025)	• Overview of the Draft Plan:
	  ◦ Plan highlights
	  ◦ Opex
	  ◦ Capex
	  ◦ Demand
	  ◦ Future of Gas
	  ◦ Tariffs
	  ◦ Network access

SARG/RRG Meeting #2 (April 2025)	• Draft Plan overview • Discussion around feedback received in submission received from SARG Review Panel
SARG/RRG Meeting #3 (May 2025)	• Presentation from the Office of Hydrogen Power SA regarding the future of hydrogen in South Australia • Addressing feedback from SARG around AGN's vision to 2050
SARG/RRG Meeting #4 Online Deep Dive (May 2025)	• Recap and discussion about tariffs, focussing on the feedback received in SARG Review Panel's submission
SARG/RRG Meeting #5 Online Deep Dive (May 2025)	• Recap and discussion about capex and opex, focussing on the feedback received in SARG Review Panel's submission

SARG/RRG Meeting #6 (June 2025)	• Final Plan overview and context:
	  ◦ Future of Gas narrative
	  ◦ Depreciation
	  ◦ Opex

SARG/RRG Meeting #7 (June 2025)	• Request of SARG/RRG members to spend time on the topics that didn't get discussed at the previous meeting due to time constraints:
	  ◦ Demand
	  ◦ Capex

<table>
<tr><th colspan="2">Future of Gas</th></tr>
<tr><th>What we heard</th><th>Support</th></tr>
<tr><td><u>Customers</u>

Customers share a continued interest in the Future of Gas in South Australia.
72% of customers noted that they understood the context of regulatory depreciation, and 24% stated they would be interested in learning more.
Customers are generally supportive of AGN's proposal to re-consult if our dollar figure for depreciation equates to a greater amount than proposed during Phase 2 workshops.
</td><td></td></tr>
<tr><td><u>SARG Review Panel</u>

SARG noted that the Draft Plan lacks a clear, strategic and detailed pathway to 2050; the 'missing chapter' needs to outline assumptions, risks, timelines, and implications.
SARG members shared concern that minimal depreciation will have a negative impact in future AA periods.
SARG want more information, clearer justification and open discussion using different terminology.
</td><td></td></tr>
<tr><td><u>Stakeholder submissions</u>

Stakeholders are supportive of AGN as a market leader however, some also share concern that we are too optimistic about the future and warn about stranded asset risk due to potential fast-paced electrification.
</td><td></td></tr>
<tr><th colspan="2">Our response</th></tr>
<tr><td colspan="2">
We have had discussions with the SARG Review Panel on how to address their feedback
We have provided more information on where we see AGN in 2050, and what our strategy is to achieve this
We note that this is a topic that our customers are eager to discuss in more detail and learn more about are projects progress.
</td></tr>
<tr><th colspan="2">Final Plan outcome</th></tr>
<tr><td colspan="2">
The Final Plan includes:

The Context of our Plan,
more detail in our Future of Gas and Depreciation chapter and detailed attachment on modelling and our approach, and
a detailed attachment on the future evolution of the energy market and our strategies for ensuring we can supply renewable gas.

We have built a model that we use to inform our depreciation position in the Final Plan.
Our modelling supports a minimum of $70 million in additional depreciation to begin to manage future risk.
However, having regard to the AER's most recent approach towards flat prices we have proposed an amount of $30 million of additional depreciation in the Final Plan.
</td></tr>
</table>

Capital Expenditure

What we heard	Support
<u>Customers</u> • 95% of customers agreed that our Draft Plan met their expectations and reflected what was important in relation to maintaining and growing our network. • Customers remain interested in learning more about our plans to grow our network.	
<u>SARG Review Panel</u> • SARG members shared a concern that $156m for new connections will create risk of stranded assets, noting falling demand and policy uncertainty. • SARG wants more clarity on how capex aligns with long-term consumer preferences and transition risks.	
<u>Stakeholder submissions</u> • Stakeholders would like greater detail on capex (e.g., meter replacements and fleet transition), and raise questions about risk management of hydrogen-related capex. • Stakeholders raised concern about potential cost overruns associated with IT upgrades, and want assurance of prudent delivery given industry-wide issues with IT implementations. • Stakeholders share support for AGN's mains replacement program that is nearly complete. • Stakeholders are mainly supportive in principle about our hydrogen projects, but want more clarity on costs, technical feasibility, sourcing, and customer impact. • One stakeholder expressed strong opposition towards hydrogen for residential use.	

Our response

- We invited SARG and RRG members to a Deep Dive on capex to address their questions and concerns about meter replacement, fleet, hydrogen readiness, IT and growth capex.

Final Plan outcome

- $155m for new connections capex which is marginally below the Draft Plan forecast (
- We are forecasting residential and commercial connections over the next AA will decline relative to the current period benchmark by 15% (34k forecast vs 40k benchmark)
- If forecast growth does not materialise, the growth capex won't be spent/rolled into the RAB. Only capex incurred is rolled into the RAB, no CESS benefit.
- We've assessed each of the four possible extension projects and have only proposed one (Concordia)
- If required we could reopen the AA to adjust forecasts in response to new policies or evolving market conditions
- We believe that connection charges are more appropriately addressed at the jurisdictional level (AEMC rule change requests) rather than through an AA proposal process

Pricing and tariff structure

What we heard	Support
Customers • Customers view gas affordability as their number one priority and express their satisfaction for our proposal to maintain stable pricing. • Customers shared concern about flattening tariff structures due to negative bill impacts for larger use customers including families and businesses. Some supported environmental benefits of flatter tariffs, noting that any change should still not compromise affordability. Customers generally supported the price cap approach (as opposed to a revenue cap) in the interests of stable pricing. • Regarding a charge for the new abolishment reference service, 49% of customers noted their preference was to continue to offer it free of charge while 38% of customers felt that customers requesting it should contribute to the cost.	
SARG Review Panel • SARG supports maintaining price stability and affordability, consistent with customer feedback. • SARG notes limited understanding among customers on tariff structures, and that we should improve communication and frame changes within broader policy context.	
Stakeholder submissions • Most submissions supported our pricing proposal for stable prices and only moderate changes to the tariff structure to align with consistent feedback from customers that affordability is their number one priority. • Some stakeholders think the price reduction should be more significant, whilst others share concern that it may lead to future price shocks. • One stakeholder noted that our tariff structure should be flat or inclining. This might encourage customers to reduce their gas usage, but as noted by customers at our workshops, customers from bigger families who rely on gas for cooking and heating their homes could be the most disadvantaged from a change in tariff structure. • On our Draft Plan hybrid price mechanism proposal (price cap with a 10% threshold for revenue variations to be passed to customers), one stakeholder noted it was a second best option to maintaining a pure price cap. • Regarding abolishments, stakeholders shared support for partial cost recovery in pricing but caution against affordability and safety risks from high charges.	

Our response

- Our Final Plan demonstrates that it is not reasonable to entirely flatten tariffs (even over two+ periods) because of the extent of bill increases for higher usage customers.
  - It is not reasonable to expect customers to forgo an essential service or buy new appliances, especially since our data suggests that many larger use customers are among those in 'financially stretched' areas.
  - It is not feasible to compensate those negatively affected; there is no such scheme in place, and this would be an inefficient approach which places additional costs on the network.

Final Plan outcome

- In our Final Plan, prices will remain steady from 1 July 2026 with a decrease of 1.0% (after inflation).
- Consistent with emission reduction objectives of the NGO, we have proposed changes to residential and non-residential tariffs with reasonable bill impacts. We have also proposed that a threshold level of 10% revenue variation be applied to our price cap approach. Our abolishment charge is proposed to be 20% of the cost ($250), consistent with the AER-approved approach.

<table>
<tr><th colspan="2">Operating Expenditure</th></tr>
<tr><th>What we heard</th><th>Support</th></tr>
<tr><td><u>Customers</u>
• Customers indicated that the continued safety and reliability of the network was important to them.
• 98% of customers indicated that AGN has ‘understood and applied what is important to me’ in relation to service proposals..</td><td></td></tr>
<tr><td><u>SARG Review Panel</u>
• SARG members encouraged cost savings where possible in our opex proposal (including regarding insurance and other cost increases).
• SARG members requested clearer explanation of opex step changes and purchasing Renewable Gas Certificates.</td><td></td></tr>
<tr><td><u>Stakeholder submissions</u>
• Stakeholders shared strong support for continuation of the PSP and recommend expanding the program where possible.
• Stakeholders supported the productivity growth factor proposed but wanted more information on the reasons for the growth rate assumed
• Stakeholders wanted more information about our UAFG assumptions.
• Stakeholders requested more detailed (but plain-English) information on step changes</td><td></td></tr>
<tr><th colspan="2">Our response</th></tr>
<tr><td colspan="2">• We invited SARG and RRG members to a Deep Dive to provide more detail about:
    ○ our proposed step changes in our Final Plan, including how they meet the prudency and efficiency tests of the Gas Rules (NGR 91),
• We also provided more information about our opex proposal generally including cost drivers, UAFG forecasts and our productivity growth assumption (based on our initial Victorian network (AGN) proposal).</td></tr>
<tr><th colspan="2">Final Plan outcome</th></tr>
<tr><td colspan="2">• In our Final Plan, we have adjusted our proposed step changes and have provided more information on all proposed step changes and other aspects of our proposal, in line with stakeholder feedback.
• Our final opex proposal seeks to maintain the safety and reliability our customers need and value, while also achieving emission reductions for a sustainable future.
• We propose opex savings and productivity improvements valued at $13 million to achieve price efficiency for customers.</td></tr>
</table>

<table>
<tr><th colspan="2">Demand</th></tr>
<tr><td>What we heard</td><td>Support</td></tr>
<tr><td><u>SARG Review Panel</u>
SARG members would like AGN to test the demand forecasts against multiple policy and technology scenarios, such as:
South Australia adopting a Victorian-style gas substitution roadmap.
Hydrogen and biomethane not becoming commercially viable within the forecast period.</td><td></td></tr>
<tr><td><u>Stakeholder submissions</u>
Stakeholders believe demand forecasts and assumptions should be more explicitly linked to investment decisions and risk mitigation strategies (e.g. accelerated depreciation).
Stakeholders would like AGN to explain how demand projections interact with long-life capex and pricing over time, especially post-2031.
Stakeholders note and acknowledge decline in demand.</td><td></td></tr>
<tr><td colspan="2">Our response</td></tr>
<tr><td colspan="2">We invited SARG and RRG members to a Deep Dive on demand forecasting to address their questions and concerns</td></tr>
<tr><td colspan="2">Final Plan outcome</td></tr>
<tr><td colspan="2">Core Energy is forecasting demand in between AEMO's step change and progressive scenarios
If connections don't materialise, the capex will not be incurred – this is the main link between the demand and capex forecasts
If there's a policy change, we would respond by reopening the Access Arrangement, adjusting demand down, and potentially increasing depreciation as risks would change
Hydrogen and biomethane not becoming commercially viable within the forecast period would not impact the demand forecast in the next period but would in subsequent periods</td></tr>
</table>

Table 5.8: Summary of customer and stakeholder feedback support

Summary of customer and stakeholder feedback	Cust	Stkh.	Retail
Services / Terms and Conditions			
• Stakeholders support our proposal to align our services and terms and conditions	N/A		N/A
Future of Gas			
General • Stakeholders are supportive of AGN as a market leader, however share concern that we are too optimistic about the future and warn about stranded asset risk due to potential fast-paced electrification. • Stakeholders note that the Draft Plan lacks a clear, strategic and detailed pathway to 2050; the 'missing chapter' needs to outline assumptions, risks, timelines, and implications. • Customers share a continued interest in the Future of Gas in South Australia.			N/A
Depreciation • Stakeholders want more information, clearer justification and open discussion using different terminology. • Stakeholders share concern that minimal depreciation will have a negative impact in future AA periods. • 72% of customers noted that they understood the context of regulatory depreciation, and 24% stated they would be interested in learning more. • Customers are generally supportive of AGN's proposal to re-consult if our dollar figure for depreciation equates to a greater amount than proposed during Phase 2 workshops.			N/A
Capital Expenditure			
General • Stakeholders would like greater detail on capex (e.g., meter replacements and fleet transition), and raise questions about risk management of hydrogen-related capex. • 95% of customers agreed that our Draft Plan met their expectations and reflected what was important in relation to maintaining and growing our network.			N/A
Growth capex • Stakeholders share concern that $156m for new connections will create risk of stranded assets, noting falling demand and policy uncertainty. • Stakeholders want more clarity on how capex aligns with long-term consumer preferences and transition risks. • Customers remain interested in learning more about our plans to grow our network.			N/A
IT • Stakeholders identified concern about cost overruns and seek assurance of prudent delivery given industry-wide issues with IT implementations. • Retailers noted that a website upgrade should be fairly proportioned to AGN SA customers (i.e. SA customers should not subsidise a website that covers AGN Vic, MGN and DBP).	N/A		
Mains replacement • Stakeholders share support for AGN's mains replacement program that is nearly complete.	N/A		N/A

Table 5.8: Summary of customer and stakeholder feedback support (continued)

Hydrogen readiness • Stakeholders are supportive in principle, but want more clarity on costs, technical feasibility, sourcing, and customer impact. • One stakeholder opposed hydrogen for residential use. • Retailers support innovation like HyP Adelaide but are concerned about heating value variability in hydrogen blends.	N/A		
Operating Expenditure			
Renewable Gas Certificates • Stakeholders request clearer explanation of step changes; especially capitalisation changes and renewable certificate placeholder.	N/A		
Opex increase • Stakeholders sought cost savings where possible. • Stakeholders need clearer explanation of step changes. • Retailers noted the $26 million allocated for hydrogen blending operations, but referenced the AER's disallowance of similar funding for Jemena.	N/A		
Priority Services Program • Stakeholders share strong support for continuation and expansion of PSP and recommend to broaden eligibility criteria.	N/A		
Capital Base			
• Stakeholders are generally supportive but request greater transparency around risk management	N/A		
Demand			

• Stakeholders believe demand forecasts and assumptions should be more explicitly linked to investment decisions and risk mitigation strategies (e.g. accelerated depreciation).
• Stakeholders would like AGN to test the demand forecasts against multiple policy and technology scenarios, such as:
  ○ South Australia adopting a Victorian-style gas substitution roadmap.
  ○ Hydrogen and biomethane not becoming commercially viable within the forecast period.
• Stakeholders would like AGN to explain how demand projections interact with long-life capex and pricing over time, especially post-2031.
	N/A		

Pricing			
Price proposal • Stakeholders support maintaining price stability and affordability, consistent with customer feedback. • Customers view gas affordability as their number one priority and express their satisfaction for our proposal to maintain stable pricing.			
Tariff structure • Customers and stakeholders supported our proposal to flatten tariffs slightly to ensure no unreasonable customer bill impacts • Stakeholders noted limited understanding among customers on tariff structures, although our engagement workshop outcomes demonstrated strong understanding from those participating. • One stakeholder noted that flat or inclining tariffs should be implemented but also advocated for a compensation scheme to support those negatively affected.			

Table 5.8: Summary of customer and stakeholder feedback support (continued)

Abolishment charges • Some stakeholders shared support for partial cost recovery but caution against affordability and safety risks from high charges. • Retailers noted concern about rising abolishment costs leading to customers permanently exiting the gas network, potentially leaving retailers without revenue but with ongoing network obligations. • 49% of customers noted their preference was to maintain AGN's current approach to offering abolishments free of charge. 38% of customers noted that a customer choosing to abolish their gas service should contribute towards the cost.			

Key:

Supportive of proposals
Somewhat supportive of proposals
Unsupportive of proposals
More information required


Safety
UniSafe

6 Future of gas and depreciation

This chapter outlines our depreciation proposal and how it forms a part of our strategy to adapt to substantial future change in the energy sector.

IN THIS CHAPTER:

- **We explain the steps we are taking to prepare for a more competitive future environment.**
- **We explain our framework for maintaining the balance of risk between networks and customers and what it means for our pricing.**
- **We outline our modelling of depreciation profiles and how this translates into a proposal for depreciation in this Access Arrangement.**

Depreciation is one part of a framework aimed at keeping the balance of risk between customers and networks stable as the energy sector changes and new risks and competitive forces emerge. We explain why our approach to depreciation has changed, and how we determine the quantum of change via modelling in this chapter.

Our Draft Plan set out our views on the potential scale and scope of future changes in the energy sector. In response to feedback on the Draft Plan, we have developed our explanation of the future challenges and opportunities for networks in this Final Plan.

In this chapter, we explain how we have taken into account the changes forecast in long-run demand for our services as the energy sector transitions in formulating our depreciation proposal. In our earlier context chapter, we outlined how we see the future of the supply side developing and how we have taken that into account, in particular, the future supply of renewable gases

We believe that renewable energy is the key factor not because it is renewable per se, but because it allows households to gain sovereignty over their own energy in a way which has not been possible before. This in turn, will likely release competitive pressures of a new and different form than have prevailed in the past in the energy sector, even for a fuel of choice.

Although the shape of this competitive future is almost impossible to predict with any degree of accuracy at this early stage, all energy networks, gas or electricity, need to adapt towards having sufficient flexibility and optionality to remain sustainable if and when this future arrives, and to do so within the constraints of the regulatory framework operating today.

We consider that the best way to do this is to have a conceptual focus on maintaining stability in the balance of risk between networks and customers. One key element in doing that is thinking carefully about our approach to depreciation.

In this chapter we start by refreshing the picture from the Draft Plan on potential future competition, with some examples. We then cover what we mean by maintaining the balance of risk between networks and customers and explain how depreciation sits within this approach.

Before we begin, we note that in this chapter and in our Final Plan we refer to “additional depreciation”, with our reference point being the amount of depreciation which would have been included if there was no change in approach from the previous Access Arrangement period.

In the past, we and other stakeholders have referred to "accelerated depreciation". As we discuss in Attachment 6.1, we believe this term will become less and less helpful as changes to depreciation become a business-as-usual part of Access Arrangement proposals, and changes will not always involve "accelerating". Depreciation is the return of the RAB through time. The RAB has a finite value and consequently, depreciation must decelerate at a point in the future. This has been an issue of debate between us and some stakeholders, in particular our South Australian Reference Group Review Panel (SARG Review Panel). We agree, however, that customers need to know how depreciation has changed compared to the status quo and the reasons for the changes. We seek to address those changes in this chapter.

6.1 Regulatory framework

NGR 89(1) provides that a depreciation schedule should be developed for an access arrangement period and makes it clear that this depreciation schedule can, and is expected to, change through time as energy market conditions change, so that pricing promotes efficient markets.

We believe that giving effect to the requirements of Section 89(1) requires us to consider the balance of risk between networks and customers through time as the energy market changes and the amount of risk being faced by networks and customers also changes.

6.2 Customer and stakeholder engagement

Depreciation is a challenging topic for customer engagement, not because depreciation itself is challenging (most people understand how a variable home loan works, and the regulatory building block model is, in principle, simple) but because understanding the forces that necessitate changes in a depreciation schedule is challenging. Rather than focussing on explaining a technical model, or asking people whether they support particular dollar amounts of changes in depreciation, we focussed on:

- Explaining the broad forces we believe will drive the energy sector going forward, and the implications for networks and consumers.
- How we have tried to make our arguments in support of changing depreciation transparent and how models can help to allow the AER to do its job in assessing our proposals.

Within this context, we did present a range of additional depreciation amounts, at differing stages of the consultation process as the modelling matured. In the Draft Plan, the change ranged from $10 to $80 per bill and in consultation with customers we asked whether they were satisfied with letting the AER rule on amounts of additional depreciation up to $40 per household per annum, or whether they would like to see the full model results once these were available. Customers largely trusted the AER to do its work, given what we had told them to date.

We had far more detailed discussion with the SARG on our views regarding our future, including both the demand side pressures that give rise to a need to consider depreciation and the supply side strategies which allow us to make credible claims about the viability of renewable gases (see below). The SARG suggested that the Draft Plan lacked detail on these points.

The discussion in this chapter, which formalises our approach to balancing risk between customers and networks has been presented to the SARG and has benefited from interaction with the Review Panel on the detail. It also benefited substantially from earlier discussions with customers and feedback through our engagement program.

Table 6.1 provides a summary of the feedback from customers and stakeholders on the topic of the future of gas and our approach to depreciation, and how we have responded to this feedback in developing our final position in this plan.

Table 6.1: Customer and stakeholder engagement on the Future of Gas

Topic	Customer and Stakeholder Feedback	Our Response
Future of Gas	**Stage 1 and 2 Engagement: Developing our Plans**	
	• Customers want to better understand the network's proposed shift to renewable gas as well as more information on the personal impact that the shift would have	• Customers had the opportunity to learn more about these plans in sessions, and we have published more as part of this Final Plan.
	Stage 3 Engagement: Draft Plan Consultation • **Does the concept of depreciation make sense to you?** • **Are you comfortable with the modelling approach we are taking to depreciation?** • **We are yet to finalise the amount of additional depreciation, but propose to come back and consult with you if the amount is greater than $40 per year. Do you support this approach?**	
	Customer feedback • Some customers expressed a desire to discuss depreciation in more detail. • Some customers were familiar with a different form of depreciation (that used by accountants for tax purposes). • Customers wanted more detail on the final number for depreciation.	• We delved deeper into how depreciation works and the nature of modelling in Phase 3. We also provided information to customers as to where they could read more about our modelling, including a model manual. This detail is in our Final Plan. • We explained and made clear what "regulatory" vs other forms of depreciation were, and how they work • In workshops, we said we would come back to customers if the final number was larger than $40 per bill, which most customers accepted.
	SA Reference Group feedback • There could be a degree of optimism in assumptions underpinning the energy transition and AGN needs to consider the impacts of currently proposed rule changes on depreciation.	• We have outlined our reasoning in detail in the Final Plan, including where we consider we have been optimistic. We have also directly discussed the current rule change proposals. We have also considered the impacts of broader policy changes, like connection bans.
	• Depreciation decisions must be openly explained and supported by modelling of customer impacts over time.	• Our Final Plan contains a detailed description of our modelling, which includes a focus on customer prices and their stability. We also provide the model and a manual. In discussions with customers, we explained how models are used to provide transparency to reasoning.
	• We need clarity on the impacts if accelerated depreciation is not applied during this period, in particular the future price consequences of waiting.	• We have explicitly modelled the consequences on consumer prices of waiting.
	• AGN should not avoid the term "accelerated depreciation".	• We have outlined our reasons for choice of language in this Final Plan and discussed it with the SARG. We support the need for transparency and openness that underpins the differing views on terminology.
	• We need to see the "missing chapter" on the future of gas that wasn't in the Draft Plan. • What is the role for sharing the cost of transition between networks and customers and how do options like new connection charges feed into this?	• We commonly do not provide all our background materials with a Draft Plan, as many are still being developed. We have provided two chapters detailing the background to the future of gas; this one focusing on the demand side and its consequences for depreciation and Chapter 1 providing detail on supply side strategies for renewable gas. Both have detailed appendices with more information. Our work on depreciation includes a wide range of simulation and analysis of different future states.
	• AGN should consider using depreciation as a tool to manage intergenerational equity and avoid future price shocks.	• We have developed a three-part "stable risk balance framework" which includes risk sharing, aspects such as connections charges and shown how depreciation fits into this.
	Stage 4 Engagement: Refining our Plans	
	• The SARG Review Panel requested that they be invited to provide advice on how we respond to their feedback.	• Various business units from AGN (Regulation, Economics and Strategy) met with members of the SARG Review Panel to ensure our response met their expectations.
	Final Plan Outcome	
	• Our Final Plan notes that our modelling approach supports a minimum of $70 million in additional depreciation to meet future risk but notes that AER practice would deliver $30 million. • The Final Plan has addressed the SA Reference Group's concerns about the "missing chapter" and provides supporting appendices which cover the demand side, inform depreciation (and how we keep long run prices as stable as we can), and outline our supply-side strategies to support the delivery of renewable gas. • Our approach to modelling to support depreciation includes consideration of a wide range of future market outcomes, including policy responses not yet deployed in South Australia. It includes consideration of customer price outcomes, rather than solely focussing on networks, and shows the impacts of waiting until the next AA. • We outline how depreciation sits within a framework aimed at maintaining a stable risk balance between networks and customers as the energy sector changes and risks change. This framework has benefited substantially from discussions with stakeholders, particularly the SARG Review Panel, and we thank members for their time to develop our thinking.	

6.3 Preparing for a changing energy sector

As we outlined in our Draft Plan, and as we discussed with customers, we consider it likely that energy networks will face new and different competitive forces in the future. Customers will likely pursue new opportunities to exploit sovereignty over their own energy needs that ownership of their renewable electricity and storage will provide them. New players will enter the market to meet this emerging demand. This competition will be very different from the type of network-on-network competition gas, as a fuel of choice, has faced in the past and will be entirely unfamiliar to electricity networks.

One early example of what the future may hold comes from expert advice supporting our depreciation model (See Attachment 6.3). In the past, resistive electric tank hot water systems have been poor competition for instantaneous gas systems because they are relatively inefficient and therefore costly to run on grid electricity.

However, a resistive tank electric hot water system which is powered by rooftop solar is a very different product to a resistive hot water system powered by the electricity grid, because the electricity to power it (provided some restrictions on its use are accepted by the customer) is essentially free most of the time. The source of competition here is not the appliance itself, but rather the fact that the customer is powering the appliance with their own power. This is a new form of competition for both gas and electricity networks.

A second example comes from the AER's recent State of the Market Report (p257, here). The AER cites research suggesting that a house which is well-insulated (as per emerging new home energy efficiency standards) and has rooftop solar can reduce its reliance on network supplied electricity to almost zero.

This is a new form of competition which comes about as designers and builders design homes which allow homeowners to leverage their ability to produce and store their own power into lower energy bills.

These two examples of new types of competition are probably only the tip of the iceberg in terms of new types and new sources of competition for energy networks. Facing new types of competition like this, as consumers work out how to make best use of their emerging energy sovereignty, is a risk all energy networks will need to face over coming decades, and one to which regulation will need to respond. As we outline below, we consider depreciation to be one useful tool to help to do this, provided it is wrapped within a framework which considers appropriate sharing of risk. First, however, we briefly address an important supply-side issue, renewable gas.

6.3.1 Renewable gas and the supply side

Renewable gas is a key part of our future and Attachment 6.4 sets out in detail our low carbon ambition and how we see our networks, and the energy sector transitioning. Renewable gas is however a gateway rather than an all-in-one solution to future risk. That is, if renewable gas as a substitute for natural gas does not become viable, then our future ability to transport gas in the longer term is likely to be limited. If the renewable gas sector does develop further and we continue to transport this new fuel in the future, although we will continue to be part of the future energy mix, we will still face all of the competitive pressures (existing and emerging) which result from customers having other choices for energy. Our approach to depreciation explained in this chapter seeks to address this risk of future competition and ensure the long terms interests of both networks and customers are met.

Further detail on our strategy towards the development of renewable gas, which gives us confidence that it will develop to a suitable price point, and that there will be enough of it to meet customer requirements is contained in the 'Context of this plan" chapter and Attachment 6.4. The relatively small opex and capex required to support renewable gas initiatives in the next five-year period are detailed in Chapters 8 and 9 respectively.

Here we address the consistency between depreciation and renewable gas. In particular, some stakeholders have suggested that spending on renewable gas and increasing depreciation are inconsistent.[1]

This might be correct if the future was a binary choice between 'success in renewable gas' meaning our business would carry on exactly as it has over the past few decades and 'failure in renewable

[1] *The Brotherhood of St Laurence made this suggestion in a submission to our Victorian AA process in 2022 (see here, p17) and more recently, the JEC has made a similar suggestion in a submission to Jemena's NSW AA process (see here, p20)*

gas' meaning decline in our network to no future at all. However, we do not consider the future to be as binary as that. Renewable gas will likely also provide a gateway to future opportunities, and our future is likely to involve new and different forms of competition, such as the examples noted above.

In this context, renewable gas spending and depreciation are complementary, because renewable gas spending helps ensure we remain as a viable alternative to other energy sources and shifting the recovery of fixed costs from the future to the present means lower future prices and improves our ability to continue to compete in the future. Indeed, if we invested in preparing our networks for renewable gas without considering depreciation, we might find we open a gateway to nowhere if we price ourselves out of future markets. Conversely, if we focus on depreciation and ignore renewable gas opportunities, we may find we have limited fuels to transport at the low prices we can achieve. Neither option is in the longer-term interest of consumers.

None of this means, of course, that we have licence to ask customers to bear any amount of renewable gas spending and any amount of depreciation; we need to test both to make sure they will deliver future benefits. And we do so in our modelling approach. However, the notion of inconsistency is, equally, based upon an overly simplistic view of the potential future pathways the energy sector might take.

6.3.2 Maintaining the risk balance as demand changes

For roughly the first 20 years of gas network regulation, the possibility that energy networks faced a future where competition might influence prices was not a consideration in regulatory decision making. Regulators used very long asset lives for asset classes, and made decisions on the assumption that networks themselves would continue as monopoly businesses with very long lives. This led to lower prices for customers compared to a situation where the possibility of future competition had been considered. The potential for competition is a new risk, which has entered the regulatory debate over the past five years. There are a number of ways these risks that arise from new competition as the energy sector transforms can be addressed:

- Keep the level of risk borne by customers constant with investors bearing all of the new risk.
- Keep the level of risk borne by networks constant with customers bearing all of the new risk.
- Sharing the new risk between customers and networks.

In our view, the first two options are untenable. Requiring networks to bear all of the new risk means higher prices if the risk is explicitly compensated for through the regulatory process. If it is not, higher prices may occur anyway as networks seek to avoid or manage the risk by changing the balance of opex and capex spending to put less capital at risk. Even if networks could not alter the opex and capex balance, the fact that prices remain low is not necessarily a benefit; if prices are low due to a risk not being reflected then this leads to consumption which is above efficient levels, storing up problems for later.

Requiring customers to bear all of the risk leads to more customers leaving the network, raising prices for those who remain. This makes the second option equally untenable.

Very few competitive markets would allocate all of a new risk to either customers or firms. Consideration should not be given to absolute levels of risk, but rather the balance of risk between customers and networks. Maintaining balance, in the face of new risk, could be achieved by:

- Networks either facing falling demand or perceiving falls in future seeking new sources of demand to make up that shortfall. Given the nature of the new risk, said new demand sources should be sustainable in a potentially future competitive marketplace.[2]
- Customers of currently regulated services (whether the customers themselves are current or new), bearing the balance of asset risk which cannot be reasonably recovered elsewhere, so long as doing so is reasonably practicable.
- New customers entering and existing customers leaving the network doing so without imposing net costs on other customers.

The first two of these points cover risk between networks and

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[2] Networks would also need to consider how sustainable their existing services might be in potentially competitive new markets. Prices and cost structures would certainly change, but it is not clear that demand for currently regulated services would fall to zero in a competitive marketplace.

customers as a group and the latter deals with risk between customers. We describe this in significantly more detail in Attachment 6.1, but what it means in practice is that, if the RAB of a network is currently $1 billion, but the network could sustain a business with a value of $500 million into a competitive future beyond the mid-2040s, then prices of currently regulated services cover $500 million in business value, leaving $500 million for future markets. Further, where possible, new connection charges and the payment of full disconnection costs could avoid socialising these costs and imposing an externality on other customers.

The place where modelling plays a key role is in the second point above in considering whether regulatory prices are "reasonably practicable"; and determining whether imposing regulatory prices on customers of currently regulated services will cause those customers to prematurely leave the network. This is not a question of fairness or of equitable sharing of costs but is a simple matter of practicality; regulatory prices which are unsustainable can play no useful role for networks or customers.

We note that the ECA has a rule change pending before the AEMC (here) which suggests mandating connection charges, and another (here) dealing with additional depreciation. We discuss the interaction between these proposed rule change approach and our framework in Attachment 6.1 and will engage with the AEMC rule change process as it unfolds.

6.4 Modelling and model results

In this section, we discuss the modelling which has underpinned our depreciation approach, and which reflects the balancing of risk approach outlined above.

The basic modelling "engine", the consumer choice model, is very similar to that which we used for our Victorian AA proposal. In particular, it still tests explicitly whether a given price increase brought about by depreciation can be sustained, or whether customers will leave the network, causing a price spiral. It also still considers price stability for customers who remain on the network.

However, there have been some tweaks to improve model operation and, importantly, we change the way we use the model, reflecting the three elements of maintaining the balance of risk outlined above. We discuss this key model framework issue below, before continuing with the model results.

6.4.1 Model framework

Our modelling framework is informed directly by the three components of the risk-balancing framework outlined above. In particular, we:

- Take the perspective of a business operating circa 2050 looking forward to a then competitive energy sector and who values the lines of business then viable using standard business valuation perspectives. For the purposes of the modelling, this value (see Attachment 6.1 for details) has been calculated to be $1 billion.[3]
- Look at our current RAB and the capex and opex needed to support the business out to 2050 and see, with no change in depreciation, whether the RAB gets down to $1 billion by 2050.
- If not, test different depreciation profiles out to 2050 using our customer choice model, to ascertain whether depreciation schedules which allow the network to reach a value of $1 billion in 2050 are "reasonably practicable" in the sense that they do not create a high risk of customers abandoning the network before that date.

We also look to the impacts of the above process if we assume that new connection costs are not included in the RAB, and whether this can allow less depreciation and thus fewer price impacts for customers now.

We describe the results of our modelling approach and process in considerable detail in Attachment 6.1, which also includes a manual to allow others to use our model, change our assumptions and test our results; something we promised customers we would do.

6.4.2 Model results

Our headline results are presented in Table 6.2. The first column shows the different policy settings and price bundles used. These are summarised in Attachment 6.1. The first policy case has no policy setting unfavourable to gas, the second has new connection costs not entering the RAB, the

[3] The approach does not turn on the exact date chosen; 2050 is simply far enough away to provide time for new competitive forces to start to manifest. To arrive at the value of RAB in 2050 for the purposes of the modelling, we assume a decline in demand for services which are currently regulated, and an increase in their costs reflective of different operations for a competitive business, and add on revenues from future business in distributed generation. Details are in Attachment 6.1.

third has a ban on new connections, and the fourth adds a hot water appliance subsidy to Case 2. The fuel and appliance price bundles range from more (Bundle 1) to less (Bundle 3) favourable to gas.

The second column, in green shows the amount of additional depreciation required to reach (on average across 1,000 price simulations) a RAB value of $1 billion in 2050. Amongst these simulations, not all allow the network to reach 2050, as sometimes, the amount of depreciation leads to all customers departing the network before then. This is shown in the third column. So, for Price Bundle 2 in Policy Case 2, $77 million in additional depreciation is needed to reach a RAB of $1 billion in 2050 (on average) and 23 percent of cases do not reach this RAB value.

The fourth column shows the proportion of cases which do not reach 2050 if no additional depreciation is applied beyond what would be applied following our current methodology, and the remaining columns give the same proportion where $140 or $270 million of additional depreciation is applied. These are provided to provide comparison points against the amounts of depreciation in column 2 in respect of the degree to which more depreciation is "reasonably practicable" by virtue of creating fewer cases where price paths cause future customers to leave the network because future prices remain too high. Further detail in this respect if shown in Attachment 6.1.

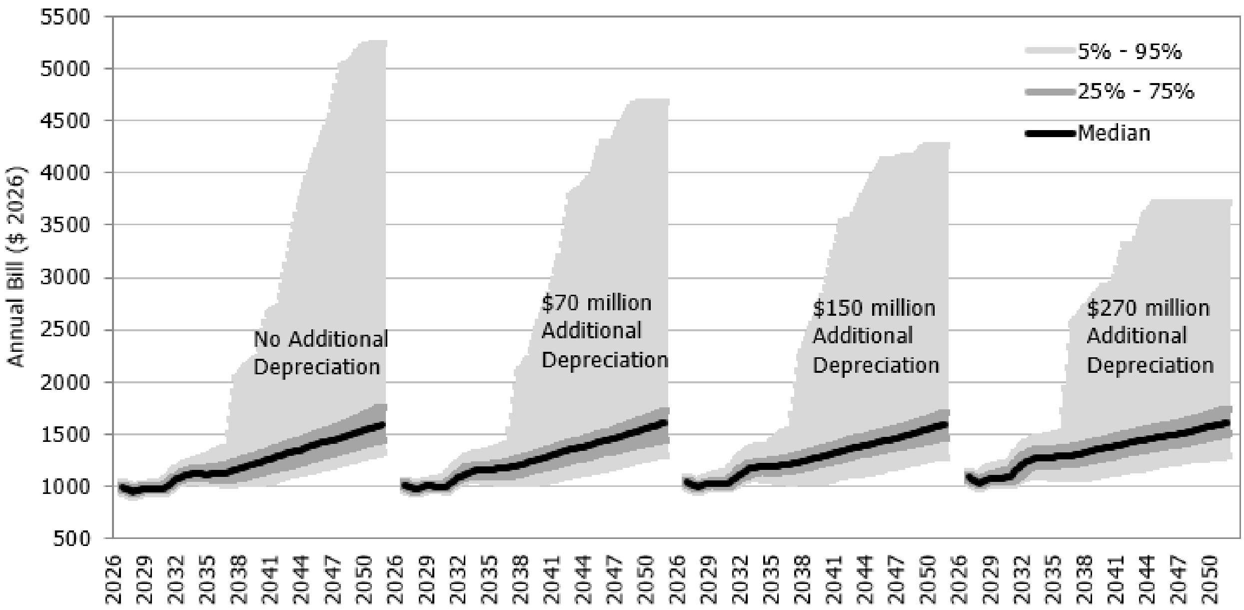
Our view at this stage is that $70 million is an appropriate amount of additional depreciation to apply. If it is combined with 'no new connections' capital expenditure entering the RAB, it is enough to keep stranding risk steady prior to 2050, or to improve it where appliance and fuel price bundles are unfavourable to gas and when new connections are minimal. It is not enough in a worst-case world, for example, where the South Australian Government begins to significantly subsidise hot water systems (which it is not yet doing). Nor is it enough if relative prices and policy settings remain relatively favourable (more customers join the network pre-2050, meaning more depreciation is required to reach $1 billion in 2050), but we do not consider that depreciation should be based on more favourable scenarios in any event.

Although $70 million of additional depreciation still leaves considerable risk on the table for our network, we believe, at this early stage, that this minimal approach is appropriate. Attachment 6.1 provides detail on the consequences to risk for larger amounts of additional depreciation than shown in Table 6.2.

Table 6.2: Headline model results - additional depreciation and pre-2050 risk (sim=simulation)

	Amount of additional depreciation to get to $1billion by 2050	Proportion of sims stopping short of 2050	Proportion of sims stopping short of 2050 with no additional depreciation	Proportion of sims stopping short of 2050 with $150 mil additional depreciation	Proportion of sims stopping short of 2050 with $270 mil additional depreciation
Policy Case 1					
Price Bundle 1	879	1%	0%	0%	0%
Price Bundle 2	150	26%	26%	26%	24%
Price Bundle 3	132	37%	43%	36%	30%
Policy Case 2					
Price Bundle 1	272	0%	0%	0%	0%
Price Bundle 2	77	23%	23%	23%	22%
Price Bundle 3	67	39%	41%	34%	29%
Policy Case 3					
Price Bundle 1	285	0%	0%	0%	0%
Price Bundle 2	77	38%	41%	36%	35%
Price Bundle 3	72	54%	61%	49%	41%
Policy Case 4					
Price Bundle 1	356	13%	12%	12%	12%
Price Bundle 2	127	35%	42%	34%	29%
Price Bundle 3	121	36%	41%	35%	29%

Figure 6.1: Long run price consequences of additional depreciation



A key additional concern with depreciation is what it might do to prices in the long term. To examine this, we look at the first policy case, where there are no policy settings which are particularly adverse to gas, and we show the results for Price Bundle 2 in Figure 6.1 for illustrative purposes. Further detail is provided in Attachment 6.1.

The median price does fall slightly through time with higher amounts of additional depreciation during the next AA. However, the key benefit comes in terms of risk; what customers are essentially "buying" with more depreciation during the next period is not lower expected prices per se (or at least, not much lower expected prices) but rather a form of insurance against adverse price outcomes in instances where the market is particularly unfavourable to gas and more customers leave; shown by the upper end of the light grey shaded area in Figure 6-1.

The value of this insurance can be quite high; $70 million in additional depreciation is roughly 2.5 percent of residential bills, but it reduces the worst outcomes for customers by 2050 by more than 10 percent. For this reason, we consider it contributes to the welfare of consumers who stay on the network (for example, vulnerable residential customers or hard to electrify industrial customers) and are affected by the actions of those who leave.

6.4.3 Applying model results in the PTRM

In our AGN Victoria Access Arrangement proposal, we applied the additional depreciation amount from our modelling to the "mains and services" asset class, as this was the longest-lived asset class and therefore the asset class with the greatest future exposure. In South Australia mains and services are separated into two distinct categories "Mains" and "Inlets" (in South Australia services are referred to as inlets). In this Final Plan we have applied the additional depreciation to the "Inlets" asset class exclusively.

As we note in Attachment 6.1, where an existing customer leaves the network before the cost of the pipe and meter needed to serve just their demand has been recovered, the extra cost of their original connection will be socialised over remaining customers. This represents an externality one customer imposes on another. Requiring a departing customer to pay the balance of the connection cost from a connection potentially made decades prior may be theoretically correct but is administratively complex. Instead, by applying the additional depreciation to the Inlets asset class, we make sure the externality declines through time, which we consider is a practical compromise.

6.4.4 Final choice for additional depreciation

Despite the minimum appropriate amount of additional depreciation being $70 million, as per our modelling results outlined above, we are mindful of the AER's "base real price limit" approach, which it uses as a "guardrail" in its most recent decision for Jemena (see Attachment 4, available here). In that decision, the "guardrail" was a 0.5 percent real price increase.

Whilst we agree that price stability over the long term is an important consideration, we don't necessarily think that an arbitrary restriction in respect of short-term price increases, which does not appear to have any link to the long run forces depreciation is intended to address, is the best approach.

We consider it is more appropriate to use a model to test the price rises associated with additional depreciation and their impacts on consumers, rather than making assumptions on what consumers will or will not bear and focussing only on consumers during the next AA period. We note that the AER also apparently has a long run model (see Attachment 4 of the Jemena decision, p19, available here) which may be able to do this, but no details about the model have been made public that we are aware of. For this reason, we have developed and use our own model for this purpose.

However, we have had regard to the AER's approach in its most recent Jemena final decision and for the purposes of this Final Plan, we propose an additional depreciation amount which does not increase real prices today, of $30 million (in dollars of 2025/26).

We intend to continue to engage with stakeholders on this issue and if the AER's views on appropriate real price changes from the last AA to this next one change, we would implement a depreciation profile in line with our model, rather than the $30 million in additional depreciation.

6.5 Summary

Our modelling approach is grounded in a framework which attempts to share the balance of the new risk which has emerged concerning the potential for future competition to emerge in the energy sector.

Starting from a position looking forward to a business value in a future competitive world post 2050 of $1 billion, our modelling suggests that $70 million in depreciation would be a conservative position for additional depreciation during the forthcoming AA period to provide a reasonable likelihood that additional depreciation is "practicable" in the sense that it does not contribute to too high a risk that customers will depart the network prematurely because of the additional depreciation.

However, given the AER's focus on close to flat real prices from the previous to the current AA, we have proposed $30 million, in additional depreciation. Should the AER change its view on flat pricing, we would revert to the conclusions of our modelling to determine depreciation.

7 Pipeline and reference services

Our pipeline and references services for the next AA period are generally consistent with those currently provided by the South Australian distribution network.

IN THIS CHAPTER:

- **We intend to maintain the same reference and non-reference services in the next AA period, but with the addition of the abolishment service as a reference service.**
- **Our haulage reference services will continue to be complemented by a range of ancillary reference services.**

We offer a range of pipeline services to meet our customers' needs.

In the current AA period, we have offered various haulage and ancillary services.

Our haulage services and main services ancillary to providing a haulage service, such as connections and special meter reads, are classified as reference services, specifically haulage reference services (HRS) and ancillary reference services (ARS).

Reference services are determined based on 'reference service factors' (RSF) including the actual and forecast demand for the service and demand substitutability.

These services, which have accounted for more than 99% of the revenue earned in the current AA period (Figure 7.1), are the basis of the reference tariffs approved by the AER.

We plan to offer the same suite of reference services in the next AA with the addition of the abolishment service being classified as a reference service.

The AER's Final Decision on our Reference Service Proposal has approved our proposed reference and non-reference services (Tables 7.1 and 7.2).

Our RSP submitted to the AER in June 2024 incorporated the feedback we received from stakeholders on our suite of proposed services, and classification of those services.

The following sections provide further detail on our proposed reference and non-reference services and the RSP process. Details of the price and other terms and conditions that will apply to the reference services are provided in Chapters 14 and 15 respectively of this Final Plan.

Reference service factors

The reference service factors in the NGR require consideration to be given to:

- actual and forecast demand for the service and the number of prospective users of the service;
- the extent to which the service is substitutable with another reference service;
- the feasibility of allocating costs to the service;
- the usefulness of specifying a service as a reference service in supporting negotiations and dispute resolution for other services; and
- the likely regulatory cost.

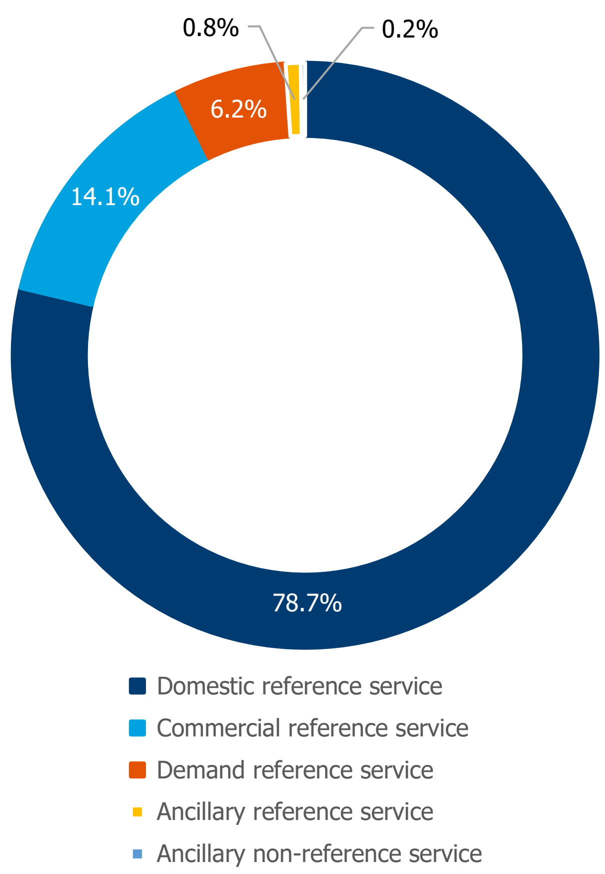
Table 7.1: Proposed reference services for the South Australian distribution network 2026/27 – 2030/31

Service	Description
Haulage reference services	
Domestic Haulage Service	A haulage reference service that comprises the delivery of gas through an existing domestic Delivery Point (DP).
Demand Haulage Service	A haulage reference service that comprises the delivery of gas through an existing demand DP. A DP is a demand DP at a given time if: (a) that DP is not a domestic DP at that time; and (b) the quantity of gas delivered through that DP during the then most recent metering year was equal to or greater than 10TJ in total.
Commercial Haulage Service	A haulage reference service that comprises the delivery of gas through a Commercial DP. A DP is a Commercial DP at a given time if that DP is not a Demand DP or a Domestic DP at that time.
Ancillary reference services	
Special Meter Read	A meter reading for a DP and provision of the associated meter reading data that is in addition to the scheduled meter readings that form part of the haulage reference services.
Disconnection	The use of locks or plugs at the metering installation of a domestic or commercial DP to prevent the withdrawal of gas at the DP.
Reconnection	Action to restore the ability to withdraw gas at a DP, following an earlier disconnection (that is, the removal of any locks or plugs used to isolate supply, performance of a safety check and, where necessary, the lighting of appliances).
Meter and Gas Installation Test	On-site testing to check the measurement accuracy of a metering installation and the soundness of the gas installation downstream of the metering installation.
Meter Removal	Removal of a meter at a metering installation to prevent the withdrawal of natural gas at the DP.
Meter Reinstallation	Reinstallation of a meter at a metering installation, performance of a safety check and the lighting of appliances where necessary.
Service Abolishment	Cut and cap of the service within the street and removal of all above ground assets (meter etc.) This service generally applies to small scale abolishment services, which covers most residential property requests. AGN will ultimately determine which cessation of supply service is applicable to each Delivery Point.

Table 7.2: Proposed non-reference services for the South Australian distribution network 2026/27 – 2030/31

Service	Description
Ancillary non-reference services	
Meter Alter Position / Removal	When a customer is requesting the relocation of an existing gas meter to a new position, or the removal of a second meter on the premises.
Out of Hours Special Meter Reading	Request for an appointment to read a meter (Special Meter Reads will be charged in accordance with location as either metropolitan or non-metropolitan).
Same Day Premium Service	Request for a service on the day of request in addition to the charge for the requested service.
Relocate/Remove Service Pipe	Relocate the service or "Inlet" pipework.
Downgrade Meter Size	A retailer request for a customer's meter to be downgraded.
Pressure Change	A customer request for a change in gas pressure and may involve a regulator.
Other Negotiated Service	A network service that is different from the Reference Services on terms and conditions.

Figure 7.1 SA distribution network revenue share 2021-24



7.1 Regulatory framework

In accordance with the National Gas Rules (NGR), we are required to include a list of all pipeline services we can reasonably offer in a Reference Service Proposal (RSP) at the start of the AA process (NGR 47A).

In our RSP, we are required to specify which services are reference services (NGR 47A(1)(c)), with regard to the reference service factors (NGR 47A(15)) listed above.

On June 2024, we provided our RSP to the AER for the next AA period. This proposal provided for a consistent set of reference and non-reference services. It also included the abolishment service being classified for the first time as a reference service.

The AER consulted on this proposal with stakeholders and in November 2024, approved our proposal for service offerings in the next AA period (Final Decision).

Our proposal to offer reference and non-reference services in this Final Plan must be consistent with the AER's RSP decision, unless there has been a material change in circumstances (NGR 48(1)(b)).

7.2 Customer and stakeholder engagement

Our proposed services reflect the feedback we received from our customers and stakeholders (Table 7.3).

We shared our proposed list of services in our Draft Reference Service Proposal, which we published for comment on 22 May 2024. Our stakeholder engagement demonstrated broad support for the continuation of our service offerings at this stage.

One focused aspect of our engagement concerned the abolishment service, which involves permanent disconnection with cutting and capping of the service at the main (for small scale connections). We now classify this type of service as a reference service for our distribution networks in Victoria. The abolishment service is currently offered free of charge in SA for public safety reasons, to reduce the risk of network assets being left idle.

Our Draft RSP noted how the policy landscape concerning new gas connections in SA is different to that in Victoria. It also noted how the current rates of abolishment in SA remain stable at a relatively low level and currently reflect abolishments for 'knock down rebuilds' where the gas service is removed and then reinstalled for a new home.

Some stakeholders indicated the importance of the abolishment service being classified as a separate service, in the interests of transparency and for any possible future rise in demand.

Our Final RSP included the classification of the abolishment services as a reference service.

We engaged further on the pricing approach for the abolishment service at our Draft Plan stage. We proposed partial cost recovery and socialisation of remaining costs for consistency with the AER's decisions to date (for distribution networks in Victoria and for Jemena's network in New South Wales).

Customer and stakeholder feedback was mixed regarding the pricing approach.

Around half of the customers we surveyed (in our Phase 3 customer workshops) indicated support for an abolishment charge of some magnitude.

Some stakeholders preferred that no charge be applied to abolishments for consistency with connections being offered free of charge in SA.

Another stakeholder (Energy and Water Ombudsman SA) indicated that the partial cost recovery approach was prudent on safety grounds but that it might not be sustainable if abolishment numbers increase dramatically.

Since then, the Australian Energy Market Commission (AEMC) has published a rule change request regarding the introduction of an abolishment charge which would apply in SA (and all jurisdictions except Western Australia), for consultation from 12 June 2025.[1]

As discussed further below, our Final Plan adopts partial cost recovery as the basis for the proposed abolishment charge ($250), pending outcomes regarding the AEMC rule change and any accompanying policy change regarding a charge.

7.3 Pipeline services

Tables 7.1 and 7.2 set out the reference and non-reference services we propose to offer in the next AA period. The classification of the services as either reference or non-reference services is broadly consistent with the classification that applies in the current AA period. It is also consistent with our June 2024 RSP, which the AER approved in November 2024.

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[1] See: https://www.aemc.gov.au/rule-changes/establishing-regulatory-framework-gas-disconnections-and-permanent-abolishment

Table 7.3: Customer and stakeholder engagement on pipeline and reference services

Topic	Customer and Stakeholder Feedback	Our Response
Pipeline and Reference Services	**Stage 1 & 2 Engagement: Developing our Plans**	

	• We received five submissions on our Draft RSP. We also shared our proposed reference and non-reference services in our customer workshops and with our stakeholder reference groups.
	• Our stakeholder engagement demonstrated broad support for the continuation of our service offerings, and stakeholders also indicated a preference for the abolishment service (small scale) to be identified as a reference service in the next AA period.
		• In our Draft RSP, we asked our stakeholders whether they:
		  ◦ supported the proposed reference services
		  ◦ preferred any classification changes for specific services from reference to non-reference, or non-reference to reference
		  ◦ had any suggestions for improving the descriptions of our services, and
		  ◦ required any additional services.
		• We proposed that the abolishment service be a reference service in our Final RSP, which we submitted to the AER in June 2024.

	Stage 3 Engagement: Draft Plan Consultation • **Do you think the pipeline and reference services we have proposed are appropriate, or do you think there has been a material change in circumstances that were approved by the AER in November 2024?** • **Do you think the abolishment reference service should be charged at partial cost recovery or full cost recovery?**	
	• We did not receive any further feedback on our proposed services at this stage, apart from on the pricing approach for abolishments. • Some stakeholders indicated a preference for a continuation of the abolishment service being offered free of charge to align with connections. • The Energy and Water Ombudsman SA indicated support for partial cost recovery on safety grounds but also considered that full cost recovery was more sustainable if abolishments were to increase dramatically. • Customer feedback in workshops indicated that they were evenly split about favouring a charge (as opposed to no charge).	• Our Draft Plan reflected the decision by the AER on our RSP (dated November 2024). • Regarding pricing for the abolishment service, we remained open to feedback but acknowledged that the likely approach would be based upon the AER's preferred approach for partial cost recovery and a charge amounting to 20% of the full cost (which is $250 based on our estimated service cost). • However, we also stated that this pricing approach (with partial cost recovery) was not sustainable if there was policy intervention to disincentivise gas connections in SA.
	Stage 4 Engagement: Refining our Plans	
	• No further feedback was provided on our proposed services and the pricing approach for the abolishment service at this stage.	• We note the current AEMC rule change request (with consultation commencing 12 June 2025) for a full charge to apply to abolishments, without any partial cost socialisation. • Notwithstanding the outcome of this rule change request, we have maintained consistency with the AER's position to date regarding the abolishment charge.
	Final Plan Outcome	
	• Our Final Plan includes the reference and non-reference services approved by the AER in our final RSP, noting there have been no changes to our proposed service offerings since. • We have proposed an abolishment service charge of $250 (representing 20% of the full estimated cost of the service in SA), for consistency with the AER's past decisions on this approach.	

7.3.1 Reference services

In the next AA period, we propose to offer three haulage services (Domestic, Commercial and Demand Haulage) and seven ancillary services for connection, disconnection and meter-related services (Table 7.1).

These services make up more than 99% of our revenues in the current AA period (Figure 7.1).

Consistent with the reference services factors, these services:

- are the most sought after services by our customers;
- are not generally substitutable with other reference services;
- have largely predictable costs that can either be attributed to individual users or reasonably allocated across users of a particular service; and
- can aid prospective users in access negotiations and dispute resolution for other pipeline services, thereby minimising regulatory costs for all parties.

Some ancillary services such as the meter gas and installation test or meter reinstallation have been specifically requested by retailers or other stakeholders to be reference services in previous periods.

In the next AA period, we are proposing that the abolishment service is an ancillary reference service for the first time on our South Australian network. The proposed classification of the abolishment service as a reference service in our Final RSP reflects:

- consistency with the current AAs applying to our Victorian distribution networks;
- how the abolishment service can be considered to meet the reference service factors under NGR 47(A)15 in that there is currently moderate demand for the service and because it is not substitutable with any other service, and
- that we can allocate costs for this service for residential properties and other small scale abolishments, because they are relatively standard in scope.

Consistent with our Draft Plan, we propose that the abolishment service charge is determined in a manner consistent with the AER-approved approach for the Victorian distribution networks and the Jemena Gas Network: based on partial cost recovery. The cost of the service to customers ($250) is proposed to represent 20% of the total cost of the service ($1,250), with the remaining costs socialised across other customers.

Since our Draft Plan, the AEMC has published a rule change request for a full charge to apply to abolishments as part of a consistent regulatory framework (in all jurisdictions except Western Australia). The AEMC's consultation on this rule change commenced from 12 June 2025 and will continue beyond the submission of this Final Plan.

To be clear, we do not consider that the partial cost charging approach is sustainable, particularly an environment of policy intervention to promote permanent disconnection from the gas network. In such a situation, full cost recovery from the customer, as opposed to socialisation across remaining gas customers, is appropriate and consistent with the requirements of the NGR.

We also acknowledge that ultimately, our plans may need to align with the outcome from the AEMC rule change request pending the timing of that decision.

7.3.2 Non-reference services

In the next AA period, we propose to offer certain non-reference ancillary services (Table 7.2). These services have been classified as non-reference services because they do not meet one or more of the reference service factors, particularly those relating to substitutability, consistency of demand (especially considering demand for these services is often low), and the ability to allocate costs efficiently (since the cost of providing the service varies markedly depending on the specific customer requirements).

7.4 Summary

We propose to maintain the current set of reference and non-reference services in the next AA period, but with the addition of the abolishment service as a reference service.

Our customers support this approach, which is also consistent with our Reference Services Proposal approved by the AER in November 2024.

We also propose that the new abolishment reference service be offered on a partial cost recovery basis (with a charge of $250) for consistency with the AER's preferred approach to date. However, we acknowledge that this approach will need to be consistent with the outcome of the existing AEMC rule change request regarding abolishment charging.

8 Operating Expenditure

We will continue to maintain an efficient operating program for our customers as we seek to prudently address key market challenges.

IN THIS CHAPTER:

- **Our opex forecasts have been developed using the base-step-trend methodology approved by the AER.**
- **Opex in the next AA period for our haulage services is forecast to be 1% lower than the current AA period benchmark, excluding our proposed change to capitalisation.**
- **Our opex forecast ensures we continue to provide the safe, efficient, reliable and high-quality service our customers value while also delivering a more sustainable energy future.**

The operating expenditure (opex) we incur supports the safe, efficient and reliable delivery of gas to homes and businesses every day. It ensures we can meet the service expectations of our customers.

Consistent with our approach across our regulated gas networks, we have developed our opex forecast for the next AA period by adopting the AER's preferred base-step-trend methodology. This means that for most opex items we look at the total costs we are incurring now and project those costs forward.

However, for some items, we develop specific forecasts having regard to the individual factors that drive those costs and where the base-step-trend is not the best approach to forecast future costs. Examples of these items are our unaccounted for gas (UAFG) and debt raising costs. Our Ancillary Reference Services (ARS) are also forecast separately based on full cost recovery for these services. Finally, we consider any new operating costs that we will incur over the AA period.

On an aggregate basis, our opex (excluding ARS) is forecast to be $464 million over the next AA period (see Table 8.1), or $479 million including ARS.

Some of the proposed increase in opex can be attributed to the increased costs associated with UAFG, which reflects the higher gas prices that we expect to pay.

Our controllable opex is forecast to be $373 million. This excludes those items of opex which are not within our control for efficiency (that is, category specific costs not rolled over from the current period like UAFG and debt raising costs, and the change in capitalisation policy and purchase of renewable gas certificates for the proposed Hyp Adelaide facility). Our forecast is around 3% lower than our allowance of

$382 million for the current AA period ($2025/26), and 17% higher than our forecast actual performance of $316 million with the impact of COVID-19 impacting expenditure.

In most cost categories, we have experienced an increase in costs from midway through the current period which flows through to the next AA period. Apart from the COVID-19 pandemic ending, there are a range of reasons. This includes additional patrols to protect from third party damage on the network, increasing costs of repairs and maintenance to meet new traffic management legislation, and higher costs of spoil management and dumping. Meeting Security of Critical Infrastructure (SOCI) cybersecurity obligations is another contributing factor to higher costs.

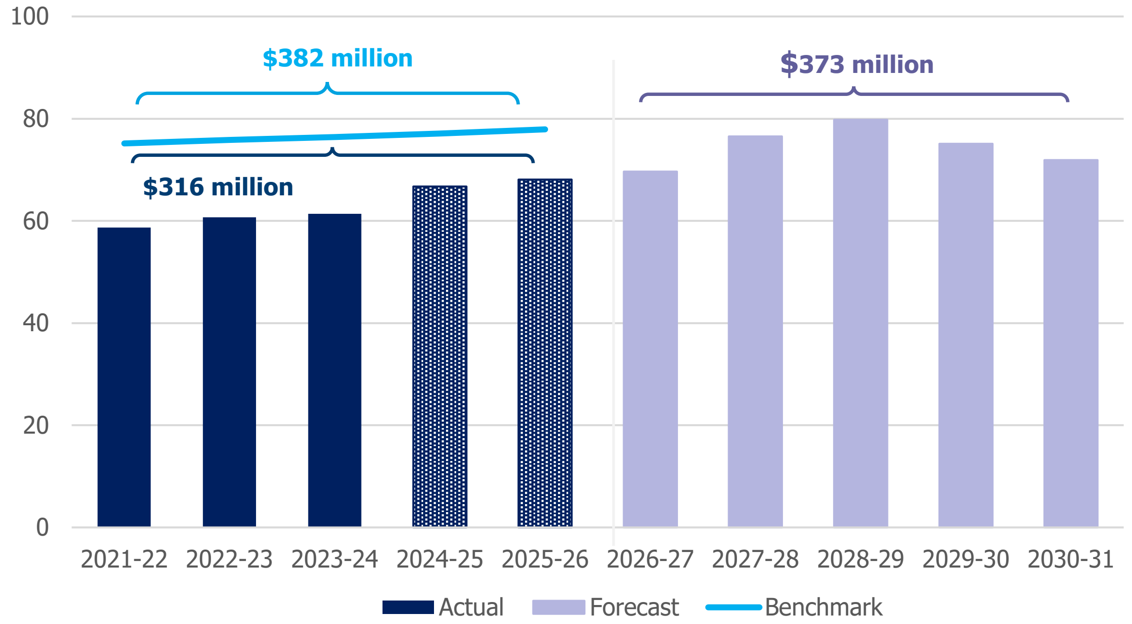
From 2026/27, we have proposed step changes integrated into our controllable opex forecasts including the abolishment of redundant services for safety reasons, non-recurrent IT costs for the transition from our existing service provider, and an uplift in our cybersecurity and other IT applications (section 8.5.1).

Table 8.1 Total forecast opex ($million, 2025/26)

	Current AA period	Next AA period	Drivers for change
Controllable opex (ex. UAFG, debt raising, renewable gas certificate purchases and the change in capitalisation policy)	315.5	373.0	✓ Cost pressures late in the current AA, key step changes and IT non-recurrent transition costs, plus the 'trend' component of our opex forecasts (real cost escalation and customer growth less productivity)
Change in capitalisation	-	32.0	✓ We are proposing to reduce the level of overheads that are capitalised into our asset base
Purchase of Renewable Gas Guarantee of Origin (RGGO) certificates		26.0	✓ We have included expenditure to purchase RGGO certificates as part of a jurisdictional scheme opportunity for the proposed Hyp Adelaide hydrogen production facility
UAFG	19.6	27.9	✓ Reflects the increase in the cost of gas, and continuing trends in the volume of UAFG
Debt raising costs	9.5	5.1	✓ Reflects the AER's benchmark of 8.1 basis points of notional forecast debt, which is lower than forecast costs
Total opex ex ARS	**344.6**	**464.1**	

Note: Totals may not add due to rounding

Figure 8.1: Controllable Opex (excluding UAFG, debt raising costs, ARS, renewable gas certificate purchases and changes to capitalisation of overheads (million, $2025/26)



8.1 Regulatory framework

In keeping with the NGR, our opex forecast must reflect the expenditure that would be incurred by a prudent gas network business, acting efficiently, in accordance with good industry practice to achieve the lowest sustainable cost of providing Reference Services to our customers.

Our forecasts and estimates must also be arrived at on a reasonable basis and represent the best forecast or estimate possible in the circumstances.

8.2 Customer and stakeholder engagement

Our customer and stakeholder engagement concerning our opex proposal is summarised in Table 8.2.

Customers told us their top priorities are price affordability, reliability of supply and maintaining public safety. In response, we have sought various savings in our forecasts to ensure efficiency, while maintaining prudent service levels. Customers were supportive of continuing with the Priority Services Program to assist customers in vulnerable circumstances. Stakeholders indicated that this program should also be expanded where possible. In response to our Draft Plan, some stakeholders requested more information about certain aspects such as step changes, which we provided in reference group meetings and as part of our Final Plan.

Stakeholders were keen to understand the proposed HyP Adelaide project and associated regulated expenditure. We held a deep dive meeting on this issue with interested stakeholders during the Draft Plan consultation.

We also discussed our opex forecasts and all our proposed step changes at this stage, which helped us to refine our forecasts and position our Final Plan. reasons ($4.6 million), non-recurrent IT costs for the transition from our existing service provider ($18.6 million), and an uplift in our cybersecurity ($1.2 million) and other IT applications ($4.1 million) (section 8.5.1). Although an increase in opex is expected to flow into the next AA period (as shown in Figure 8.1), the opex incentive mechanism under which we operate, coupled with our internal and external controls, will continue to ensure that the opex we incur is both prudent and efficient. Our revenue in the next AA period is expected to be $9 million lower than it otherwise would be due to a negative carryover amount from the incentive scheme. This will predominantly offset any increase in the base year (as discussed in Chapter 13).

We have also identified a number of other costs that we have decided to absorb into our proposed cost base, which together with forecast productivity growth, represents around $13 million in savings over the next period (see Section 8.6). T

The following sections provide further detail on the standard our forecasts must meet under the regulatory framework, the forecasting method we have used and our forecasts for the next AA period. All numbers quoted are expressed in 2025/26 dollars, unless otherwise stated.

Table 8.2: Customer and stakeholder engagement on our operating expenditure forecasts

Topic	Customer and Stakeholder Feedback	Our Response
Operating expenditure	**Stage 1 & 2 Engagement: Developing our Plans**	
	• Customers expect a high level of public safety and reliability for the network. • Customers are satisfied with current customer service levels concerning safety and reliability, with price affordability otherwise most important to them. • Stakeholders also sought consideration of cost savings in our forecasts.	• We consulted on a small insurance step change including its materiality and responded to feedback at a SARG meeting to remove it from our proposed cost base. • We considered other opportunities to achieve savings in our opex forecasts, without compromising the safety and reliability that our customers need and value.
	Stage 3 Engagement: Draft Plan Consultation • **Do you have any feedback on the operating activities we have proposed as part of our forecast for the next AA period?** • **Do you support our approach to forecasting opex? Is there sufficient information to understand our proposals and the basis of costs included in our forecasts?**	
	• One stakeholder supported the change in capitalisation policy and our approach to forecasting UAFG and opex; another supported our IT and renewable gas (hydrogen) initiatives. • The SARG Panel requested more justification for the planned purchase of renewable gas certificates for Hyp Adelaide and other step changes. • The Panel also wanted more information about the UAFG forecasts and assurance that we will seek the most competitive price for UAFG. • Various stakeholders commended the Priority Services Program (PSP) and the Panel suggested further steps to broaden the reach of the program, and to monitor and enhance it. • On trend factors, the Panel supported the productivity growth factor but requested more information on why 0.4% has been assumed.	• We adjusted our proposed step changes following our Draft Plan and have provided more information on all proposed step changes in Section 8.5.1. • Our assumed price for UAFG is based on current market prices and in our Final Plan we have provided additional information on our UAFG strategy and quantity forecasts in Attachment 8.4. • We will continue and expand upon our Priority Services Program into the next AA period, as indicated on the next page. • An explanation of the productivity growth assumption in our Final Plan is provided in Section 8.5.2.
	Stage 4 Engagement: Refining our Plans	

	• In the SARG meeting of 5 June 2025, stakeholders acknowledged the additional step changes, including those addressing cybersecurity risks, aligned with targeted security profiles.
	• Stakeholders also acknowledged that the proposed step change related to Hyp Adelaide was part of the anticipated regulatory requirements attached to a jurisdictional scheme, rather than a broader expenditure proposal in our plan for the project.
		• We engaged further with stakeholders on the need for the proposed step changes, including:
		  o How the change in capitalisation policy was similar to additional depreciation in that it reduces the growth of the capital base.
		  o The anticipated regulatory requirement to purchase renewable gas certificates.
		  o That the proposed IT transition costs are non-recurrent (with future savings).

	Final Plan Outcome	
	• Our final opex proposal seeks to maintain the safety and reliability of our network, while also achieving emission reductions for a more sustainable energy future. Our forecasts reflect extensive customer and stakeholder feedback and we propose to absorb various costs to achieve price efficiency for our customers.	

Our Priority Services Program

Since the launch of our Priority Services Program (PSP) in SA in 2023, we have made a meaningful impact in providing assistance to our priority customers:

- In June 2024, we implemented an upgraded Customer Relationship Management (CRM) system to support customer registrations.
- We have 142 South Australian customers under the program (up until end May 2025) with:
  - Gas appliance safety checks; and
  - Emergency gas appliance repairs.
- We launched an accessibility toolbar for our Australian Gas Networks website in February 2025.
- We established a dedicated priority customer service role within AGN to work directly with vulnerable customers to resolve complaints, liaise with community organisations, develop referral programs and contribute to the setting of an appropriate policy framework.
- We participated in the South Australian Financial Counsellors Association (SAFCA) inaugural *Bring Your Bills Day* in Northern Adelaide to connect directly with customers.

We have also continued to work with stakeholders from the social and community services sector, along with our Trade Partners, to continue to refine and promote the program.

Our PSP was awarded the 2024 Service Champion for the Customer Service Project of the Year by the Customer Service Institute of Australia, through their annual Australian Service Excellence Awards.

Our plans for the next AA period include expanding our program to provide more targeted support for customers experiencing vulnerability. New initiatives include:

- a pilot program to support occupants of crisis accommodation who may be unable to engage with us directly;
- the rollout of heater servicing for all PSP-registered customers; and
- enhancements to communication accessibility for all standard communications. Field crews will be equipped with translated phrasebooks, and we are exploring additional safety devices for inclusion in the program.

We look forward to continuing to engage with stakeholders to inform and improve the Priority Services Program and assisting our priority customers into the next AA period.

8.3 How we develop our opex forecast

Our opex forecast for the next AA period has been developed using the base-step-trend approach. Figure 8.2 provides an overview of this approach.

A bottom-up approach has been used to develop category specific forecasts for opex categories that cannot reasonably be estimated using the base-step-trend approach (i.e. debt raising and UAFG costs).

We have also used bottom-up costing for our proposed step changes.

The use of this approach is consistent with the AER's preferred approach and the approach we have used in prior AA periods.

8.4 Our opex forecast for the next AA period

The following sections set out how each element of our opex forecast has been developed.

Figure 8.2: Forecasting method used for opex

Step 1 Base

Determine the base year opex that will be used to forecast opex in the next AA period by:

(a) taking the opex from the penultimate year of the current AA (by virtue of the operation of the Efficiency Benefit Sharing Scheme, expenditure in this year represents a prudent and efficient base for forecasting opex);

(b) adjusting the base year opex determined in (a) to remove:

(i) the effect of one-off (or non-recurring) costs;

(ii) those opex categories where the base-step-trend method does not produce the best forecast (e.g. unaccounted for gas and debt raising costs); and

(iii) account for the effect of any reclassification of capex to opex and vice versa.

Step 2 Step

Account for any step changes in opex that are expected to occur over the next AA period (e.g. as a result of changes in legislative or regulatory obligations) that are not adequately compensated for in the base year or rate of change.

Step 3 Trend

Account for **changes in** input costs, output growth and productivity growth that is expected to occur in the next AA period through the application of a 'rate of change' to the base year opex and, where relevant, step change opex, where:

rate of change = input cost escalation + output growth – productivity growth

Step 4

Category specific forecasts for other opex categories

Add the expenditure that is expected to be incurred for other opex categories that can't be forecast using the base-step-trend approach (e.g. unaccounted for gas and debt raising costs)

8.5 Base year opex

Selecting our base year

Under the base-step-trend approach, the actual costs incurred in the penultimate year of the current AA period are used as the basis for forecasting costs in the next AA period. This year represents the most up to date actual cost information available at the time that the AER will make its decision.

The penultimate year of the current AA period is 2024/25. At this point, we do not have the actual costs for this year in full. We have therefore based our estimate of the 2024/25 base year in this Final Plan on the actual opex incurred to March 2025 and a forecast for the remaining three months of the financial year.

We intend to update this forecast with the full year of actual opex when it is available towards the end of 2025.

Removal of non-recurrent opex

As noted in Figure 8.2, once the base year costs are determined, it is adjusted to remove any non-recurrent costs.

The opex we have forecast to incur in 2026/27 reflects our current forecast for expenditure on recurrent activities only.

Inclusion of other recurrent opex

We must also adjust the 2026/27 estimate for any new recurrent expenditure that occurs in 2025/26, after the base year (from 2024/25) has been established.

Although we have identified additional cost pressures from 2025/26, including the additional labour required for network monitoring as part of implementation of the SCADA alarm management and control program at the national level, we have decided to absorb these costs (around $0.2 million) into our overall cost base.

Our total proposed savings in our plan are discussed in section 8.6.

Removal of opex categories to be forecast separately

The final adjustment that must be made to the base year costs is to remove those opex categories for which category specific forecasts are required to better estimate efficient costs.

We have developed separate forecasts for the costs associated with ARS such as connections and special meter reads, UAFG and debt raising costs. As shown below, we have excluded the estimates for these costs from the 2024/25 base year estimate.

Base year opex used for forecasting

Category	2024/25 forecast
Total opex	76.0
Minus ARS	2.6
Minus UAFG	4.5
Minus Debt raising costs	2.3
Base year for forecasting	66.7

The base year opex based on nine months of actual data and three months of forecasts is $66.7 million. This amount will need to be updated following the AER's Draft Decision to reflect the actual full costs incurred in 2024/25.

While some revisions may need to be made, the revised costs can be assumed to be both prudent and efficient given the operation of both:

- the opex incentive scheme (see Chapter 13), the objective of which is to provide a continuous incentive to pursue efficiencies and achieve the lowest sustainable cost of providing services in every year; and
- our internal and external controls on asset management, procurement and financial governance (see section 9.7), the objectives of which are to ensure we undertake opex in a prudent and efficient manner, in accordance with good industry practice.

The AER has noted in the past that unless it has evidence that the revealed opex in a proposed base year is materially inefficient, it can use the revealed costs of the service provider for its alternative opex forecast."[1]

8.5.1 Step changes

The next element of the base-step-trend approach requires any 'step changes' in costs in the next AA period to be identified. Step changes may arise from changes to legislation, regulatory obligations or new activities.

[1] AER 2015, "Attachment 7: Operating Expenditure | Draft Decision Australian Gas Networks 2016 to 2021", November 2015, pg. 7-14.

We have identified six potential step changes in opex as in Table 8.3. Figure 8.3 in section 8.5.3 also shows the step changes in the context of our overall forecasts by category.

Accounting for changes to capitalisation of overheads

As indicated in Table 8.3, one of the main step changes proposed in our Final Plan is for a portion of capitalised overheads to be expensed from 2026/27. We discuss this is detail in this section as unlike our other step changes, we do not include additional supporting information as an attachment to this plan.

Our capitalised overheads account for around $11 million of expenditure per year. These overheads relate to activities undertaken, such as:

- operations and maintenance for capital projects, including senior management costs;
- network analysis, design, mapping and costing support in relation to network extensions and modifications;
- costs associated with procurement of vehicles;
- technical assurance, which includes technical audits, employee training and competency assessment;
- costs of providing design and engineering services for high-pressure and non-standard distribution assets; and
- indirect costs to support the provision of the above activities such as human resources and HSE.

Consistent with our approach for our distribution network in Victoria, and approved by the AER, we have identified a portion of these activities which are more akin to operating expenditure than capital expenditure. These activities are:

- operations and maintenance for capital projects, including senior management costs;
- costs associated with procurement of vehicles; and
- indirect costs to support the provision of the above activities such as human resources and HSE.

To account for this capitalisation policy change in the opex forecast, 59% of the forecast capitalised overheads from 2026/27 to 2030/31 have been included in our opex forecasts. This results in a proposed opex step change totalling $32.0 million (averaging $6.4 million each year). An offsetting change has been made to lower our capex forecast for the next AA period.

Therefore, the reclassification of these costs will have no effect on our overall costs, because the increase in opex arising from the reclassification will be offset by a reduction in capex.

Reclassifying these activities as opex is considered a more efficient option for expenditure allocation and reduces the growth in our asset base. With this in mind, it can be considered similar to the impact of adjusting depreciation as it leads to a lower Regulated Asset Base.

Table 8.3: Proposed opex step changes

Nature of step change and expenditure need	Cost in plan
Change in capitalisation policy towards overheads Under this proposed capitalisation policy change, 59% of overhead expenditure will be expensed rather than capitalised in the next AA period. This is consistent with the approach for our Victorian distribution networks, approved by the AER, and reflects a more efficient allocation of costs. There is no change to our total expenditure from this proposal, but there will be a reduction in the growth of our asset base.	$32.0 million
➔ See Section 8.5.1 for more information	
Purchase of renewable gas certificates for the proposed Hyp Adelaide project Our Final Plan includes proposed recurrent expenditure from 2028/29 of $8.7 million as part of a potential jurisdictional scheme in South Australia for the network to purchase Renewable Gas Guarantee of Origin (RGGO) Certificates for the proposed Hyp Adelaide hydrogen production facility. Under this potential scheme, certificates acquired would be sold to our industrial customers to offset their emissions and eventually wholly offset certificate purchase costs. Indicative estimates for the project suggest that on average, it will create the equivalent of 809,863 GJ in renewable gas certificates annually to the end of the AA period (2030/31) and that these will be sold to industrial customers at an assumed contracted price of $4/GJ. The proposal is consistent with our priority to deliver a more sustainable energy future for our customers, tied directly to the SA Government's emission reduction objectives and targets, and therefore, also the National Gas Objective (NGO). Other costs for the potential Hyp Adelaide project are not proposed to be part of either the Regulated Asset Base through capex, or other operating costs, for the network. At the time of publishing the Final Plan, the potential jurisdictional scheme has not yet been finalised by the Government, but more information will be provided to stakeholders and the AER once available.	$26.0 million
➔ See Chapter 4 (Section 4.4) for more information	
Non-recurrent IT transition costs The proposed IT transition step change is for the non-recurrent opex we will incur in insourcing the APA service delivery contract at the end of its 30-year term (on 1 July 2027). Capital expenditure associated with the transition for the AGN Victorian network (also historically outsourced to APA) was approved at the last review (see Chapter 9 for a discussion about our SA-based capital expenditure proposal). The Business Case (SA241) for the transition explains how the proposed expenditure meets the prudency and efficiency requirements of the NGR (91). Our approach to minimise service risk and costs involves replicating APA's current environment for AGN, before merging and transforming the two environments into one consolidated and optimised end-state environment. This is the lowest cost and lowest risk approach over 10 years and ensures that the transition occurs in a short timeframe, while providing opportunity for rationalising processes and systems, and leveraging our broader IT environment for efficiency. The additional opex required over the AA period is for software applications ($10.9 million), infrastructure, security and connectivity arrangements ($7.1 million) and IT support ($23.0 million). Other estimated costs are for forecast transition services at the end of the contract, with these costs to be offset by the estimated service charge that will cease at the end of the outsourcing contract (together reducing the additional cost in our forecast by $22.4 million). The transition is an AGN-wide program, and so the transition costs are allocated to AGN SA based on its share (35.4%) of AGN total customers only.	$18.6 million
➔ See the Business Case for the IT Transition at Attachment 9.4 for more information	

Redundant site abolishments for safety We are proposing to permanently remove service line from 3,500 redundant 'inlet only' services on our network. These residential services have a live supply to the metering location, including a vertical standpipe, but no meter in place. The standpipe is normally isolated by a closed ball valve with a cap. This situation arises when meters are removed due to billing issues, renovations or construction work, and a new meter is not re-installed. Redundant sites are considered as locations that have not had gas meters for over 24 months. This means the customer is not using gas and may not be aware that they have live gas assets on their property. It is current practice to reduce the risk to the customer and other members of the public. Leaving a redundant customer inlet connection live unnecessarily exposes the service to the risk of damage from third party work and potential leak and ignition. To eliminate this risk, we need to implement a proactive program aimed at removing these redundant services within a reasonable timeframe. Our goal is to address the backlog over a five-year period, at a rate of 700 services per year. Our assumed unit rate for abolishment in SA is $1,250.	$4.6 million

→ See the Distribution Mains & Services Integrity Plan - Confidential (Section 2.2.1.3) at Attachment 9.3 for more information

Cybersecurity uplift As a responsible pipeline operator, not only must we ensure the ongoing security of network assets, we must also ensure our data and our customers' data is secure. This is required by our Foreign Investment Review Board (FIRB) conditions, as well as Security of Critical Infrastructure (SOCI) and Privacy legislation. To properly address new cyber risks and ensure we meet these obligations, we require an uplift in our capabilities. We have proposed a risk-based program.	$1.2 million

→ See the Business Case on Cybersecurity - Confidential (Attachment 9.4)

Other IT applications upgrades and enhancements Various IT corporate applications need to be upgraded or replaced by newer applications to ensure they are fit-for purpose so we can manage technology risks and prevent material outages, thereby maintaining the integrity of our services. This includes applications hosted on the SAP RISE cloud platform and/or offered on a Software as a Service (SaaS) basis. Over the next AA period, the required expenditure for these upgrades and enhancements accounts for $2.2 million in recurrent opex, with cost estimates based on market rate testing. Our Final Plan also includes proposed non-recurrent expenditure of $0.9 million to run operational technology (OT) applications in a steady-state environment (which are currently operated by our outsourced provider, APA), to best manage risks to our services associated with the transition period. It also includes an uplift in recurrent opex of $0.6 million for ongoing data and storage costs for integrating digital metering data into our metering and billing system (Oracle CC&B), and a $0.2 million uplift in opex to implement required data centre infrastructure.	$4.1 million

→ See the Business Cases on Corporate Applications, Operational Applications and Sustaining Infrastructure (Attachment 9.4) for more information

8.5.2 Trend

The final element of the base-step-trend approach requires consideration to be given to the extent to which our costs are expected to change over the next AA period from:

- input cost escalation;
- output growth; and
- productivity growth.

These three factors are accounted for through the application of the trend rate of change to the base year opex and, where relevant, any step changes.

In our Final Plan, we have assumed a trend rate of change, averaging 0.7% per year from 2026/27.

Further detail on the key determinants of this rate of change is provided below.

Input cost escalation

The input cost escalator accounts for costs that are expected to increase at a different rate than inflation (real cost escalation).

To calculate the input cost escalation rate, we have applied the AER benchmark weights as follows:

- labour costs are assumed to account for 71% of our opex and are forecast to grow in real terms by an average annual rate of 1.1% per year over the next AA period; and
- materials costs are assumed to account for 29% of our opex, on average, and are assumed to grow in real terms by 0% per year over the next AA period.

The growth rate assumed for labour costs is based on a weighted average of the Wage Price Index forecasts for Electricity, Gas, Water and Wastewater Services in South Australia and Construction Industry, developed by Oxford Economics.

The materials cost growth rate is based on the growth rate assumed by the AER in recent regulatory decisions for AGN, which is zero.

The application of these assumptions results in a real (i.e. before inflation) average annual input cost escalator of 0.8% per year over the next AA period.

Output growth

The output growth factor accounts for the additional opex we will incur as a result of the forecast growth in output.

Our proposed output growth factor is based on the forecast growth in:

- customer numbers over the next AA period; and
- kilometres of network over the next AA period.

These forecasts, which are also incorporated in our capex and revenue forecasts in Chapters 9 and 14 respectively, have been weighted consistent with the AER benchmark rates, with customer numbers given a 51% weighting and kilometres a 49% weighting.

The application of these assumptions results in an average annual output growth rate of 0.3% per year over the next AA period.

Productivity growth

In applying the 'base year roll-forward' approach, the AER considers whether there should be an adjustment to capture the benefits of any potential future efficiency gains by the business.

We considered this issue in our recent AGN Victoria and Albury AA (from 2023/24). The AER had approved productivity factors in its Draft Decision, before Victorian policy developments impeded the growth of the network and productivity improvements were no longer considered feasible.

We therefore applied a productivity growth estimate of 0% per year in our AGN Victorian and Albury AA, which was accepted by the AER.

Given that the policy environment is different in SA compared with Victoria, we have proposed to apply in SA the productivity improvements that were initially endorsed by the AER for our AGN network in Victoria. These growth estimates were informed by the Opex Partial Productivity Study for our AGN (Victoria and Albury) network by ACIL Allen in July 2022.

We consider that there are scale benefits and other synergies across our AGN network operations which justify similar assumptions for productivity growth on our SA network. Our final assumption (of 0.4% per annum) also continues the annual average productivity growth which applies to our opex allowance in the current AA period.

8.5.3 Category specific forecasts

As noted above, separate forecasts have been developed for UAFG costs and debt raising costs. The way in which these costs have been estimated is outlined below.

As previously stated, Figure 8.3 shows these forecasts in the context of all our forecasts by category (excluding ARS).

UAFG forecast

UAFG is the difference between the quantity of gas entering the network and the quantity of gas delivered to our customers. This difference may arise from leaks, metering inaccuracies and/or gas theft.

Consistent with the approach taken at the last AA review, we have forecast the volume of UAFG as an average of the last three years of settled UAFG volumes. More information on our UAFG history and quantity forecast is contained in Attachment 8.4.

Our UAFG forecast has then been calculated by multiplying:

- the annual average volume of UAFG in the last three years; *by*
- the forecast average price of gas, which is based on current market indications for securing firm gas to meet our UAFG quantity requirements in the next AA period.

The application of this method produces a forecast of $27.9 million for the next AA period. The increase in our forecast cost (compared with actual cost for the current AA period) is driven by the increase in the market gas price.

In a similar manner to our current AA, we are proposing to deal with the uncertainty surrounding the forecast gas price through the inclusion of a 'true-up' adjustment in our tariff variation mechanism.

Lower or higher contracted prices than forecast will then be passed through to our customers. This should address the difference in timing between our contracted price and our forecasts. There are currently no cost pass throughs for UAFG quantity differences, as this would unnecessarily pass on price volatility to our customers from one period to the next.

Debt raising cost forecast

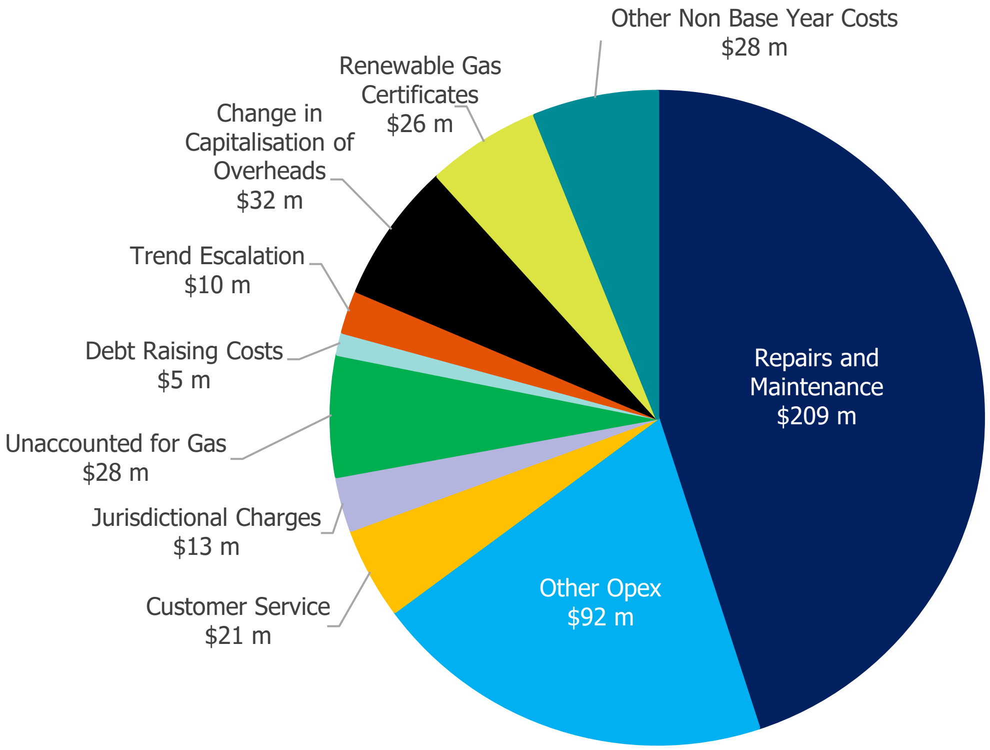
Debt raising costs are the costs businesses incur when raising or refinancing debt and the costs associated with maintaining a debt facility.

Our debt raising cost forecast is $5.1 million over the next AA period. We have applied the AER's method of assigning 0.08% of notional debt for debt raising costs. This is lower than the cost allocation we proposed in our Draft Plan which was informed by our actual debt raising costs (these are currently around $1.2 million more annually than the benchmark allows for).

As discussed in section 8.6 below, we have decided to absorb these additional costs as savings in our opex proposal, consistent with our customers' priority for price affordability.

We note that the Rate of Return Instrument (RoRI) review by the AER is commencing in July 2025, which will include a review of the calculation of the debt raising cost allowances.

Figure 8.3: Opex forecast for next AA period by category ($ million, 2025/26)



Ancillary Reference Services

Our forecast for Ancillary Reference Services applies the more recent annual volume of services (2023/24) multiplied by the current price (for 2025/26) for the service.

Excluding the new abolishment reference service, we forecast $10.4 million in Ancillary Reference Service costs. This compares with our forecast of $11.8 million in the current AA period, with the difference being due to our expectation that 95% of past meter removals will be replaced by the abolishment service.

For the abolishments service, we have forecast the volume over the AA period by taking the number of abolishments over the most recent 12 months (to end May 2025) and adjusting this by the assumed annual percentage growth in residential disconnections in our demand forecasts.

To determine our revenue for the next AA period ($4.9 million), we have multiplied the volume by the proposed charge of $250. This amount is included in the ARS forecasts in Table 8.4. Our net cost to deliver the service ($19.5 million) is based on the socialised portion of the cost ($1,000 equal to the proposed cost of $1,250 minus the proposed charge of $250).

As there is a level of uncertainty regarding these forecasts, we have also proposed a cost pass through for the variation in our forecast from the actual abolishment costs we incur each year (see section 14.6.4 in Chapter 14). A similar cost pass through for abolishment costs currently applies in our Victorian distribution network AAs.

8.6 Proposed opex savings in the next AA period

Our final opex forecasts are set out in Table 8.4.

Our opex proposal excludes various costs that we are proposing to absorb into our cost base in the next AA period. These costs are for:

- Debt raising – our proposal of $5.1 million is likely to be around $5.8 million lower than our actual debt raising costs over the next AA period, based on the 2024/25 estimated cost ($2.2 million);
- Insurance – we have excluded from our opex forecast $0.3 million in additional premium costs over the AA period, as advised by our insurer (Attachment 8.2);
- Network monitoring – we are proposing to absorb $1.0 million in additional opex identified in the Business Case for Network Pressure Monitoring for the labour involved in 24-7 monitoring (Attachment 9.4); and
- We are also proposing to absorb $0.3 million in additional opex for hazard testing, assessments and other operational work as identified in the Network Adaption Project Business Case to help ready the network for renewable gas- (Attachment 9.4).

We estimate that the labour productivity growth assumption that we have factored in (section 8.5.2), yields a further $5.4 million in opex savings over the next AA period.

Table 8.4: Opex forecast summary ($ million, 2025/26)

	2026/27	2027/28	2028/29	2029/30	2030/31	Total
Base year opex forecast	66.9	66.9	66.9	66.9	66.9	334.7
Change in capitalisation	6.4	6.4	6.4	6.5	6.3	32.0
Purchase of renewable gas certificates	0.0	0.0	8.7	8.7	8.7	26.0
Other step changes	1.7	8.3	11.0	5.6	1.9	28.4
Trend factors	1.0	1.3	1.9	2.5	3.1	9.8
UAFG	5.6	5.6	5.6	5.6	5.6	27.9
Debt raising costs	1.0	1.0	1.0	1.0	1.1	5.1
Total opex ex ARS	**82.7**	**89.5**	**101.4**	**96.9**	**93.6**	**464.1**
Ancillary Reference Services	**2.9**	**3.0**	**3.1**	**3.1**	**3.2**	**15.3**

Altogether these savings in our opex proposal total $12.8 million, which demonstrates efficiency and prudency in our approach to forecasting our opex needs.

8.7 Summary

As Table 8.4 shows, we expect to incur $464 million in opex excluding ARS (or $479 million including ARS) over the next AA period. Around $32 million of our forecast opex is for a change in capitalisation policy regarding our overheads, which does not change our total expenditure (combining opex and capex), but rather, is a more efficient allocation of this spend. A further $18 million is for non-recurrent costs (insourcing transition-related) that won't continue into the subsequent AA period.

Our projected opex in the next AA period is prudent and efficient amidst a range of market challenges, including a higher cost operating environment and the energy transition. It aligns with our strategic vision by:

- Being **customer-focussed** – we will respond to leaks on our network (to ensure public safety) and maintain our network assets as required by our asset management plans, along with other operational activities to maintain our strong safety, reliability and customer service performance. We remain focussed on how we can strengthen the customer experience of the next AA period, which includes continuing our Priority Services Program for customers experiencing vulnerability into the next AA period;
- Being a **leading employer** – we will continue to undertake workplace health and safety programs, and employee and contractor training and development initiatives to maintain a healthy, safe and skilled workforce;
- Achieving **operational excellence** – almost half of our proposed opex is for repairs and maintenance expenditure including our haulage and ancillary reference services ($224 million). In addition, we have planned a proactive program of abolishments of redundant sites in the interests of safety.

  Customers are protected to a large degree from the upward cost pressures we are facing by the operation of the opex incentive scheme and the effective price reduction it offers in the next period. We are also proposing a number of savings as well as continued efficiency through our labour productivity factor; and
- Fostering **sustainable communities** – by building on the past success of projects such as Hyp SA (Hydrogen Park SA – see section 4.4) with the Hyp Adelaide initiative, we will continue to deliver sustainable infrastructure for SA into the future.

9 Capital expenditure

Our capex forecast is lower compared to the current AA period and will help maintain our strong safety, reliability and service performance.

IN THIS CHAPTER:

- **Investing $503 million in capex, a $45 million reduction relative to the estimate for the current period, while sustaining our strong track record of network safety, reliability and customer service.**
- **Targeted protected steel mains and continued muti-user services replacement following the successful completion of low-pressure mains replacement in the current period.**
- **Connecting around 34,000 new customers over the next AA period, due to continued growth in South Australia.**

The capex we incur is necessary to ensure gas is supplied in a safe and reliable manner, and to continue to deliver valued services to our customers.

Consistent with prior AA reviews, our capex forecast has been determined using a bottom-up approach, with separate forecasts developed for our proposed expenditure on activities that:

- are customer focussed;
- promote operational excellence;
- enable us to be a leading employer; and
- support sustainable communities.

The application of the bottom-up approach has been informed by our Asset Management Strategy (AMS) and Asset Management Plan (AMP), risk management framework, regulatory obligations and projected network growth.

Our capex is forecast to be around $503 million in the next AA period, which is 8% ($45 million) lower than what we expect to incur over the current AA period (see Table 9.1).

More specifically, our expenditure on mains replacement will substantially decrease as we complete the replacement of our low-pressure mains on schedule in the current AA period.

Offsetting this reduction is an increase in unit rates reflecting significant increases in labour and contractor costs. The unit rates for mains and services were determined in a recently concluded tender and therefore reflect current market rates. This unit rate increase is further compounded by the introduction of new standards requiring more extensive traffic management at our worksites.

The following sections provide further details on the regulatory requirements in relation to capex forecasting, the methodology used and our expected expenditure in the next AA period.

Table 9.1: Actual and forecast capex by our strategic pillars, including overheads ($million, 2025/26)

Vision	Current AA period	Next AA period	Drivers for change
Customer focussed	$196.6	$215.1	✓ New customer connections ✓ Higher rates and volumes for meter replacement ✓ Digitalisation and modernisation of customer service
Operational Excellence	$337.0	$240.9	✓ Lower volume of mains & services integrity programs ✓ Continued replacement of older services at Multi-User Sites. ✓ Upgrade of field assets (such as regulators and valves) to maintain network integrity, reliability and safety ✓ IT integration
Leading Employer	$14.7	$14.5	✓ IT infrastructure renewal, upgrade systems for Health Safety and Environment (HSE) and Human Capital Management (HCM), and replacement of vehicles and small plant equipment
Sustainable Communities	N/A	$32.5	✓ Replacement of protected steel mains, renewable gas adaptation
Total	**$548.3**	**$503.0**	

This chapter also provides an overview of our performance during the current AA period and outlines our approach to ensuring that the capex we incur is both prudent and efficient.

All financial figures quoted in this section are expressed in 2025/26 dollars, with real cost escalation applied and overheads excluded, unless otherwise stated.

9.1 Regulatory framework

Our AA proposal must include:

- the forecast capex for the next AA period; and
- the capex incurred (or forecast to be incurred) in the current AA period.

Our forecast capex must reflect that required by a prudent gas distributor, acting efficiently and in accordance with good industry practice to achieve the lowest sustainable cost of providing Reference Services to our customers.

The key objectives driving forecast capex include, but are not limited to, the following:

- maintaining and improving safety;
- ensuring pipeline integrity;
- complying with our regulatory obligations;
- maintaining our ability to meet customer demand on the gas network; and
- assisting in achieving South Australia's emissions reduction targets through the supply of services.

Any forecast or estimate we provide must be arrived at on a reasonable basis and represent the best forecast or estimate possible in the circumstances. Furthermore, the overall economic value of the expenditure must be positive, including value accruing due to a reduction in emissions driven by the expenditure.

9.2 Customer and stakeholder engagement

We have developed our capex proposal in consultation with our customers and stakeholders.

Customers have told us their top priorities are price/affordability, reliability of supply, and maintaining public safety.

Customers highly value our track record of performance for both reliability and public safety and expect this to continue. Customers expressed that they are satisfied with our network growth plans.

Customers and stakeholders are satisfied with our current customer service levels, but expect that digital communication channels will become increasingly available. We are proposing to invest in IT projects aimed at enhancing online services for our customers, for instance notifications around connection and disconnection.

Table 9.2: Summary of customer and stakeholder engagement on capex

Topic	Customer and Stakeholder Feedback	Our Response
Capital expenditure	**Stage 1 and 2 Engagement: Developing our Plans**	
	• Customers told us that their top priorities are price and affordability, reliability of supply and maintaining public safety. • Customers expect a high level of public safety and feel that safety is currently well managed by AGN. • Customers highly value an uninterrupted supply of gas in their homes and businesses.	• We proposed to maintain our current levels of safety and reliability, and to ensure that customers continue to be able to communicate directly with AGN through a variety of digital channels. • We proposed to spend $158.6 million on new residential and business connections to our network.
	Stage 3 Engagement: Draft Plan Consultation • **Do you have any feedback on the capex activities we have proposed as part of our forecast for the next AA period?** • **Do you support our approach to forecasting capex? Is there sufficient information to understand our proposals and the basis of the costs excluded?**	
	• 95% of customers agreed that our Draft Plan met their expectations and reflected what was important in relation to maintaining and growing our network. • Customers remain interested in learning more about our plans to grow our network. • SARG members share concern that $156m for new connections will create risk of stranded assets, noting falling demand and policy uncertainty.	• We invited SARG and RRG members to a Deep Dive on capex to address their questions and concerns about meter replacement, fleet, hydrogen readiness, IT and growth capex.
	Stage 4 Engagement: Refining our Plans	
	• Stakeholders would like greater detail on capex (e.g., meter replacements and fleet transition), and raise questions about risk management of hydrogen-related capex. • Stakeholders raised concern about potential cost overruns associated with IT upgrades, and want assurance of prudent delivery given industry-wide issues with IT implementations. • Stakeholders share support for AGN's mains replacement program that is nearly complete. • Stakeholders are mainly supportive in principle about our hydrogen projects, but want more clarity on	• Our Final Plan forecast for new connections capex is (34,000 connections, $155m) and meter replacement (119,000, $38m). • We are forecasting residential and commercial connections over the next AA will decline by 15% relative to benchmark. • If forecast growth does not materialise, the growth capex won't be spent/rolled into the RAB. Only capex incurred is rolled into the RAB, no CESS benefit. • We've assessed each of the four possible extension projects and have only proposed one (Concordia) • We could always reopen the AA to adjust forecasts in response to new policies or evolving market conditions – similar to our approach in Victoria. • We believe that connection charges are more appropriately addressed at the jurisdictional level (AEMC rule change requests) rather than through an AA proposal process.

	costs, technical feasibility, sourcing, and customer impact. • One stakeholder expressed strong opposition towards hydrogen for residential use.
	Final Plan Outcome
	$155m for new connections capex which is marginally below the Draft Plan forecast. We are forecasting residential and commercial connections over the next AA will decline relative to the current period benchmark by 15% (34k forecast vs 40k benchmark). If forecast growth does not materialise, the growth capex won't be spent/rolled into the RAB. Only capex incurred is rolled into the RAB without any CESS benefit. We've assessed each of the four possible extension projects and have only proposed one (Concordia). If required, we could reopen the AA to adjust forecasts in response to new policies or evolving market conditions. We believe that connection charges are more appropriately addressed at the jurisdictional level (AEMC rule change requests) rather than through an AA proposal process.

We have developed our capex proposal in consultation with stakeholders. We presented our early capex proposals to our reference groups in September and October 2024 before presenting our full proposal in February 2025 which included our network asset integrity management, meter renewal, IT expenditure forecast, network augmentation and expected customer growth.

We completed three phases of stakeholder engagement and then undertook additional engagement beyond Phase 3 which aimed to address specific issues raised through the engagement process after the release of our Draft Plan. These meetings were held in May and June of 2025.

The primary message we received from stakeholders was that they expected us to continue our high standards of safety and reliability, and that our forecast costs are efficient. We will demonstrate this in section 9.7 of this Chapter.

9.3 Our capex over time

Our capex is driven by our safety and environmental obligations, the requirements and expectations of our customers and the age, performance and condition of our assets.

Figure 9.1 shows our actual and forecast capex over the current and next AA period.

We are on track to deliver the entire low pressure mains replacement program in the current period as planned. We are incurring higher costs over time in relation to our mains replacement, meter replacement and growth capex, primarily driven by unit rates.

By the end of the current AA period, all cast iron, unprotected steel, and other high-risk low/medium-pressure mains will be removed from our network. Going forward, the program will continue on a smaller scale with targeted, proactive replacements of protected steel mains that operate at higher pressures.

We are also on track to deliver the key required aspects of our IT program within benchmark in the current period.

9.4 How we develop our capex forecast

Our capex forecast for the next AA period has been developed using a bottom-up approach, with the cost of undertaking each project estimated separately. This section describes how we develop the key elements of our capex forecast, being the proposed activities and forecast costs, in more detail.

Figure 9.1: Current and next AA period forecast capex ($million, 2025/26)

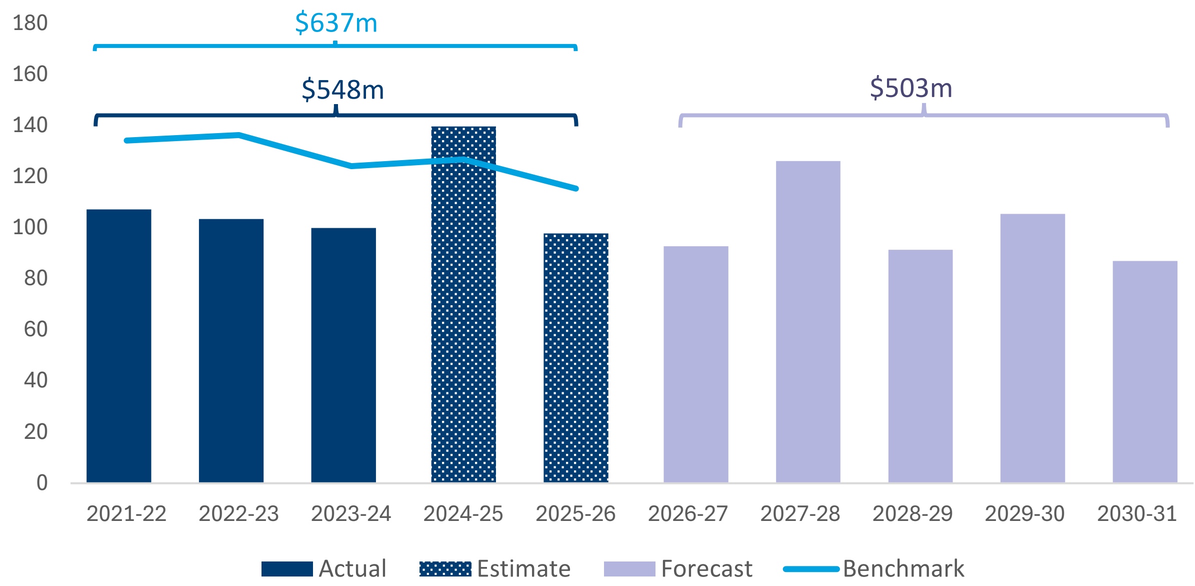


Figure 9.2: How we develop our regulatory business cases and AGN’s risk matrix

RISK MATRIX

Likelihood	Impact: Catastrophic	Major	Significant	Minor	Minimal
Frequent	Extreme	Extreme	High	Intermediate	Low
Occasional	Extreme	High	Intermediate	Low	Low
Unlikely	High	High	Intermediate	Low	Negligible
Remote	High	Intermediate	Low	Negligible	Negligible
Rare	Intermediate	Low	Negligible	Negligible	Negligible

Health and Safety
Environment
Operational Capability
People | Compliance
Reputation & Customer | Financial

9.4.1 Determining our investment priorities

Most of our investment reflects the continuation of existing programs that we undertake to ensure strong safety and reliability of our network and compliance with our regulatory obligations.

The process used to identify projects for delivery is shown in Figure 9.2. As this figure shows, potential projects and program activities are identified by asset managers having regard to our AMS, AMP, risk management framework, regulatory obligations and projected network growth.

The proposed projects and programs are then subject to review, risk ranking and phasing based on cost, deliverability and efficiency.

For the higher ranked programs proposed within the regulatory period, comprehensive business cases are developed to facilitate a more detailed assessment of the options available to address the identified issues while ensuring the costs of these options are considered and that the relevant provisions in the NGR are met.

In contrast, programs that are lower ranked or discretionary are typically deferred.

Mains replacement in the next AA period will be on a much smaller scale than the current AA period and will focus on small sections of protected steel mains in the network. This follows the significant replacement program of old low/medium pressure mains that has been a key focus in the current and prior AA periods that has seen around 3,000km of mains replaced over nearly the last three decades.

We are also proposing to invest around $1million in several new initiatives aimed at enhancing our customers digital experience, ensuring our communications with customers are aligned with current expectations. This includes initiatives such as enhancing our customers’ digital interactions with us at the time of connection and disconnection, thereby bringing our service delivery up to the standard expected by customers.

Mobile alerts would be received so that customers can plan around when work is being completed on their property. It would also enable customers to communicate with us through a chatbot on our website and receive up to date information on their gas services.

Similar to the program being rolled out in Victoria, we are proposing to install digital meters at inaccessible and unsafe properties, significantly reducing estimated reads and bills. We are obligated to read meters every 12 months in South Australia, however there are a number of properties where this is not possible due to safety or accessibility issues.

9.4.2 Forecasting efficient costs

Our forecast costs must be efficient, reasonable and represent the best possible forecast or estimate given the circumstances.

We have two categories for forecasting efficient capex costs to ensure these requirements are met. They are:

- unit rate categories, where the forecast cost is based on a unit rate price multiplied by the volume of activity to be undertaken in the period; and
- non-unit rate categories, where the forecast cost is built up based on the scope of work outlined within the project or program.

The unit rate categories include:

- Growth capex:
  - Mains – to new estates, existing homes, commercial and industrial customers;
  - Services – to new homes, multi-user sites, existing homes, commercial and industrial customers; and
  - Meters – new domestic, commercial and industrial meters.
- Meter Replacement – periodic meter change (PMC) – covers domestic, commercial and industrial time expired meter replacement; and
- Mains Replacement – in line camera inspection and reinforcement of AGN's oldest high-density polyethylene (HDPE) mains, replacement of high pressure small diameter steel mains and renewal of older services at multi-user sites.

In this Final Plan, unit rates are based on either:

- current tendered rates; or
- internal and external specialist engineering estimates or comparable quotes.

New contractor rates come into effect on 1 July 2025 after a competitive tender process for the new mains and services contracts (incorporating new estates, existing homes, multi-user sites and I&C customers). The estimated impact of these new rates are incorporated into this capex forecast. This ensures that the unit rates we have used reflect current market rates.

While we have endeavoured to reflect the best estimate possible in the circumstances, several factors are expected to place upward pressure on unit rates over the next AA period including:

- higher contractor costs driven by prevailing cost trends and the balance of supply and demand for labour in South Australia's utilities industry;
- suppliers ceasing to offer the service of refurbishing domestic meters necessitating the purchase of new more expensive meters;
- an allowance for an increase in the cost of new meters when our current national meter supply contract ends in June 2026; and
- changes in standards requiring contractors to shift from inhouse traffic management to third-party traffic service providers, with cost projections adjusted to account for the associated additional expenditure.

The non-unit rate categories include augmentation, IT, regulators and valves, telemetry, other distribution and other non-distribution projects and programs. Each project or activity is supported by a business case.

Forecast costs for these works is based on tender or contract information, current actual or historical costs for similar works or internal/external specialist engineering estimates.

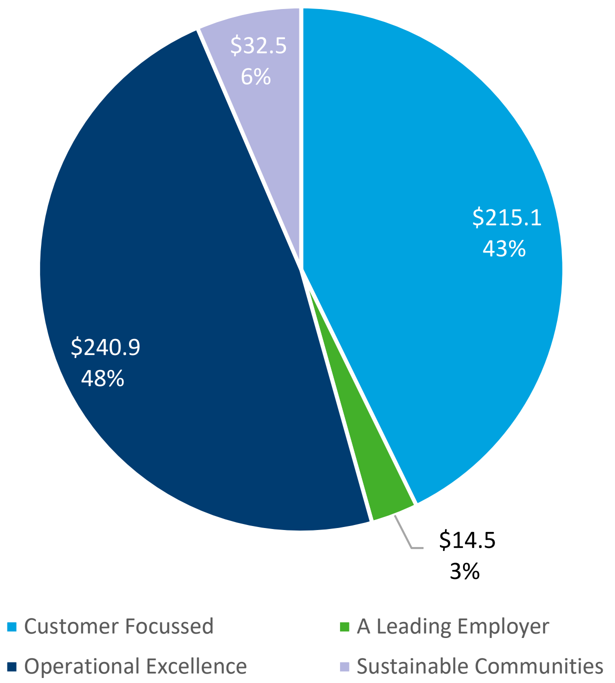
9.5 Capex alignment with our strategic vision in the next AA period

Our capex program aligns with our corporate strategic pillars, which are listed below:

- Customer focussed;
- Operational excellence;
- A leading employer; and
- Sustainable communities.

As shown in Figure 9.3, 48% of our forecasted capex is dedicated to achieving operational excellence, ensuring the capital programs are delivered safely, reliably, on time and to the highest quality standards. Additionally, 43% of our capex is driven by our commitment to being customer focussed, which

Figure 9.3: Next AA capex forecast by AGIG vision and strategic pillars ($million, 2025/26)



enables us to provide the services our customers require and value.

9.5.1 Operational excellence

In the next AA period, we propose investing $241 million in targeted projects and programs to sustain our high standards of public safety and operational reliability.

Our investments will focus on critical asset integrity and risk mitigation initiatives, including ongoing integrity dig-ups and modifications to our high-pressure transmission mains to enable In-Line Inspection (ILI). We will replace ageing regulators, valves, telemetry and cathodic protection equipment while also implementing measures to minimise overpressure risks at District Regulating Stations (DRS).

Following the completion of our highest risk (Priority 1) Multi-User Sites (MUS) service renewals, we will proceed with the medium risk (Priority 2) MUS renewals to further enhance network integrity and reliability.

We will insource our IT operations due to our operational contract ending in 2027, which will be completed via a lift, shift and merge process, moving closer to our strategic goal of having a single IT environment for our employees and customers. Additionally, we will invest in the ongoing maintenance and strategic upgrades of our core IT business systems to ensure they remain up to date, fit-for-purpose, resilient to cyber threats and continue to support our business operations efficiently.

9.5.2 Customer focussed

Customers are at the centre of our capex planning. We propose to invest $215 million in the next AA period on projects and programs that will meet customer needs and sustain our strong track record of customer service.

A significant portion of this investment will support network connections, including laying reticulation mains and services, and installing meters to connect around 34,000 new residential and commercial customers. This ensures our network remains capable of meeting evolving customer requirements while maintaining high service standards.

We will also augment our network in both the north and the south extremities of the network to accommodate sustained growth in these areas, safeguarding service levels for both existing and new customers.

To uphold our commitment to our customers, we propose investing $38 million in our meter replacement program which will systematically replace ageing meters to ensure the accuracy of customer billing is maintained.

Additionally, we will modernise IT systems that support our customers' digital experience, including improved information for customers when they connect or disconnect from the network and insights into their gas bill.

9.5.3 A leading employer

We plan to invest $15 million in projects and programs in accordance with our vision to be a leading employer. We will replace ageing vehicles and obsolete plant and equipment in the next AA period. Our vehicles and equipment undergo regular maintenance and are replaced based on age, usage and condition to minimise potential risks to employees and ensure a safer, more reliable and efficient work environment.

We propose upgrading our Maximo software with mobility support, proving employees with access to data, reducing manual tasks and streamlining workflows. This will make work easier, improve coordination between teams, and enhance overall efficiency and job satisfaction.

9.5.4 Sustainable communities

We will continue with our mains replacement program, focussing on a more targeted initiative to replace protected steel mains. This program falls under our sustainable communities strategic pillar because, in addition to increasing network safety, it will help reduce emissions by lowering unaccounted for gas (UAFG) on the network.

We are also proposing a small amount of capex ($7m) to ensure the gas network remains safe and reliable and that we can bill our customers fairly once renewable gases are injected into the network. We consider the proposed expenditure is consistent with achieving State and Federal emissions reductions by facilitating the injection of renewable gases into the network. By investing in targeted upgrades — such as replacing incompatible components, enhancing operational safety through materials testing and welding procedures and improving data systems for accurate billing—we will support the ongoing use of existing infrastructure. This phased and strategic approach will minimise disruption and promote energy equity and reliability, all while helping to future-proof the network in a way that benefits both customers and the broader community.

9.6 Capex drivers in the next AA period

The following sections provide further detail on the drivers of the activities we propose to undertake in the next AA period.

The activities under each of these areas are supported by our business plans and individual business cases. Our business cases assess the options considered to address the identified issue, the estimated cost of each option, the untreated and residual risk for each option, and alignment with both our vision and the capex requirements of the NGR.

9.6.1 Mains replacement

We are pleased to report that by the end of the current AA period, we will have removed all the cast iron, unprotected steel and other identified highest risk low and medium pressure mains from our network. The mains and services replacement program has now spanned more than three decades.

After reaching this significant milestone, the program will continue as a small scale targeted, proactive replacement program.

As a result, expenditure on mains and services replacement will reduce by $131 million (61%) from $216 million to $85 million in the next AA period.

In the next AA period, we will invest $85 million (excluding overheads) to:

- proactively replace 12.6 km of protected steel mains located in high density and key risk areas;
- allow for the unplanned replacement of approximately 5km of protected steel mains (based on historical failure rates);
- conduct 105 km of inline camera inspections and reinforcement of HDPE 575 mains including samples of vintage HDPE mains and clamps for laboratory testing;
- continue our ongoing program and target the renewal of Priority 2 MUS assets. Under

Figure 9.4: Example of hard site prior to MUS renewal and how we address the risks

the MUS program, we are on track to have renewed 163 Priority 1 MUS and removed the risk of a further 632 sites through surveying in the current AA period. We forecast to replace 960 sites in the next AA period; and

- reactively replace approximately 2,450 services due to failure, damage or non-compliance (based on historical failure rates).

9.6.2 Meter replacement

Gas meters measure the volume of gas delivered to a home or business, which helps calculate the customer's gas bill. We undertake periodic meter changes to replace old meters to ensure meter accuracy is maintained.

Based on the age and performance of our current fleet of meters and the metering accuracy requirements we must adhere to, we need to replace approximately 119,000 meters over the next AA period at a total cost of $38 million. This is an increase on the estimated 80,000 periodic meter changes to be completed in the current AA period at a forecast cost of $21 million.

The increase relative to the current AA period reflects:

- considerably lower than normal volumes in the current AA period due to extended meter life as a result of field life extension testing. This resulted in a 3-year period of reduced meter changes in the current AA period;
- a forecast amount of $3 million in the next AA period to install digital meters at unsafe or inaccessible properties to ensure compliance with our obligation to read meters every 12 months, while also enhancing metering performance and efficiency, and providing customers with better insights into their gas usage; and
- higher meter costs, with an expected increase in the cost of meters at the end of the current national supply contract in June 2026 and suppliers ceasing to offer lower cost refurbished meters during the current AA period, with the full impact of this change to be felt in the next AA period.

We have used a consistent forecasting approach to determine the number of periodic meter changes required. While the meter change volumes in the 2026-2031 AA period have increased relative the current AA period, they are 26,500 lower than the 2016-2021 AA period.

9.6.3 Augmentation

Augmentation supports the continued growth of the network by ensuring pressure levels are maintained for our customers in areas with high connection growth. We are always monitoring the pressure and performance of our network and are subject to minimum operating pressure requirements.

As the number of connections to our network grows, we can see a reductison in pressure (all other things being equal) as more gas is withdrawn from the network. Network modelling also takes into account less predictable sources of demand such as that from large commercial and industrial users. We use this monitoring data and network modelling to determine areas where our network is becoming constrained and requires augmentation.

We are seeing continuing growth in the northern and southern edges of our Adelaide network and consider that two augmentation projects will be required to maintain network pressure within the required range in the next AA period.

In the north of Adelaide we will invest $4 million to extend our network to Angle Vale, a newly established area. The project is after the commissioning of a gate station in Gawler in 2025 which will support continued load growth in the northern area.

In the south we will invest $2 million to augment the Seaford Aldinga high pressure (HP) network, providing increased capacity for the growing southern metro network, without impacting existing customers' supply.

9.6.4 Telemetry

We use a Supervisory Control and Data Acquisition (SCADA) system to monitor and report gas flow, temperature and pressure at critical locations across the network, including City Gate stations, DRS, network fringe points and demand customer sites.

Remote Terminal Units (RTUs) are a key component of the SCADA system, responsible for collecting and encoding network data. In the next AA period, we will invest $3 million to replace ageing and technically obsolete RTUs. Additionally, we will continue installing new pressure monitoring equipment ($1 million) to maintain accurate gas flow and pressure data collection as the network expands and evolves, while also ensuring asset integrity.

Figure 9.5: Welding on a transmission pipe to install a new valve

9.6.5 IT Systems

Our IT systems support several core functions including billing, finance, asset management, operations, regulatory reporting and customer service.

In the next AA period, we plan to invest $92 million in IT. The uplift compared to the current period is largely driven by a significant program to transition and bring inhouse a number of our IT applications during the next AA period.

Whilst this IT forecast closely aligns with the Draft Plan forecast at a total level, there have been a number of refinements, including adjusting the phasing of expenditure to the expected timing of the end of the operational contract on 1 July 2027.

The transition period will be a particularly intense period for our IT team as they lift and shift the outsourced environment to AGIG's environment. These two IT environments will be run in parallel during the transition period (expected to be between 12 and 18 months), which in turn minimises operational risk.

The merge of the environments, i.e. the data migration, will then occur after the transitional agreement ends. This delay in the merge of applications until after the transition period is to avoid the risk of potential issues being encountered in the migration phase, which is very possible because of the inherent complexity of migrating data from one environment to another. By delaying until after the transition period, the risk of serious operational interruption is significantly reduced.

Furthermore, application upgrades should not be attempted in parallel to the transition process, so extensive research into the costs of not complying with the vendor recommended upgrade cycle has been completed, in order to accurately estimate the costs that will be incurred as extended and sustained support is required.

The preferred option in the transition business case (SA241), is to utilise a Lift, Shift and Merge strategy, which allows for operational risk mitigation during the critical transition period and then provides the opportunity to rationalise the suite of IT software, realising synergies in the medium-term.

Our forecast also includes:

- continuing our AGIG One IT Strategy initiatives, including strengthening our cyber security capabilities in light of new regulatory and legislative requirements and the evolving cyber threat landscape;
- upgrading our website and digital platform to optimise customer experience;
- periodic major and minor upgrades to our current suite of critical applications, such as Maximo, GIS, and metering & billing systems, to ensure they are functional, cyber-secure, and supported by the vendor;
- renewal of network and end-user devices such as laptops, audio/visual equipment and servers that support critical business functions to ensure they remain current, fit-for-purpose and resilient to security threats.

9.6.6 Growth

We lay new reticulation mains, services and install meters to connect new customers to our network where it is economically and commercially viable.

We will invest $155 million to connect around 34,000 new residential and business customers over the next AA period. This includes new homes and businesses in greenfield and infill developments, as well as existing homes and businesses connecting to our network for the first time.

This includes an extension of our network to a new residential development (Concordia, $5 million) which is located in outer northern Adelaide.

Some stakeholders have raised concerns in relation to the connection of new customers creating stranded asset risk, noting falling gas demand and policy uncertainty. In respect of the above, we note that our connection forecast reflects our expectations of customer growth and will be further assessed against the capex criteria as the projected connections actually proceed over the next five years. To the extent customer choice or policy changes negatively impact actual connection growth then growth capex will be commensurately reduced because of the lower connections or through requiring customer contributions to ensure the capex is meets the conforming capex criteria.

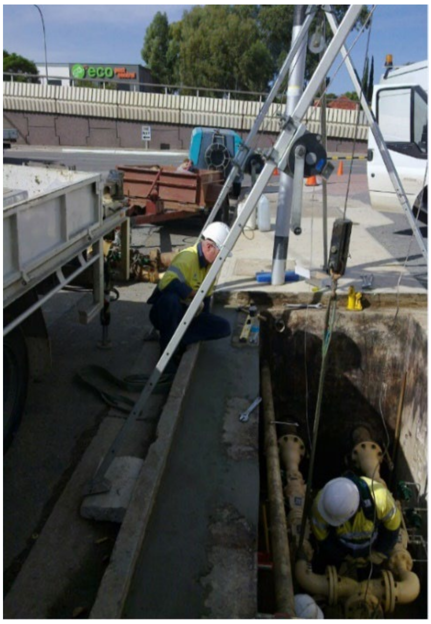
We note there is a rule change request on foot with the AEMC in relation to connection charges, which we believe is the best avenue for the consideration of this matter. Should there be a rule change either prior to the AER's Final Decision or during the next AA period, we would reopen the AA and adjust our growth forecasts and any other relevant forecasts, as a connection charge may have an impact on the forecast over the five year period.

9.6.7 Other distribution system assets

We plan to invest $92 million in other distribution system assets. The largest projects in the upcoming AA period involve:

- continuing modifications to our high-pressure transmission mains to enable in-line inspection (ILI) in accordance with accepted good industry practice ($38 million);
- reducing overpressure risk for DRS facilities ($12 million);
- continued steel pipe integrity management ($16 million) through cathodic protection equipment improvement and end of life replacement, performing external corrosion direct assessment (ECDA) or dig ups, and coating on pipework and air-to-soil interfaces; and
- replacing ageing valves ($13 million).

Figure 9.6: Confined space work rebuilding a Distribution Regulator Station



Network adaption project

We are adapting our gas distribution network to enable the delivery of renewable gases, including up to 20% hydrogen blends. This is essential to support Australia's transition to a low-carbon energy future.

Gas will continue to play a critical role alongside electricity in meeting energy needs—particularly for industries that cannot easily electrify and for households that still rely on gas for everyday use. Reaching net zero emissions will require decarbonising both electricity and gas.

Rather than simply assuming the gas network will become a stranded asset and massively augmenting the existing electricity network to deliver the equivalent energy via electrons, adapting our network for renewable gas ensures continued use of existing infrastructure.

Recognising the pathway to a decarbonised pipeline network is still evolving, we propose a phased and targeted program at strategic locations over 10 years, with $8 million capex estimated over the next AA period. The proposed investment is to:

- replace pipeline components in areas where renewable gas injections are planned, with components that are compatible with renewable gases ($0.7 million);
- undertake hardness testing and develop welding procedures to ensure the safety of our workforce ($5.7 million); and
- add functionality to our Historian software, which stores and manages operational data in order to record zone-specific higher heating values (HHV). This enhancement is essential to ensure the accurate billing and fair customer charges as network hydraulics change over time and new sources of gas enter the network ($1.6 million).

9.6.8 Other non-distribution system assets

We will invest $8 million on other non-distribution system assets during the next AA period. This includes the ongoing procurement and replacement of plant and equipment based on asset age, condition and evolving business needs. Additionally, we will replace trucks and other vehicles once they become unsafe or inefficient to operate and maintain.

We also plan to update our current leak detection system, the Selective Methane Leak Monitoring Approach (SELMA) which is reaching the end of its technical life. Possible replacements include newer technology from a company called Picarro, which produces a vehicle that is driven around distribution mains and conducts leak surveys. Picarros vehicles can detect a wider range of gas emissions than SELMA and measure gases with higher precision. This investment will bring us into line with standard industry practice.

9.6.9 Overheads

Overhead costs are operating costs that are not directly attributable to the output of distribution business but are necessary to support operations.

We undertake network planning, technical assurance and engineering activities within our business that contribute to the delivery of our capital program. The costs of these activities and services are capitalised and applied as a capital overhead across the program. In the next AA period, we propose expensing overheads associated with operations and maintenance, and corporate support functions.

On average, 70% of these overhead costs are fixed and 30% are variable, depending on the total size of our capital program. Based on current costs and the projected scale of our capex program in the next period, we propose capitalising $23 million of overhead to capital projects (around 5% of capex), while reclassifying the remaining $33 million in overhead cost as operating expenditure.

9.6.10 Summary of our capex forecast by driver

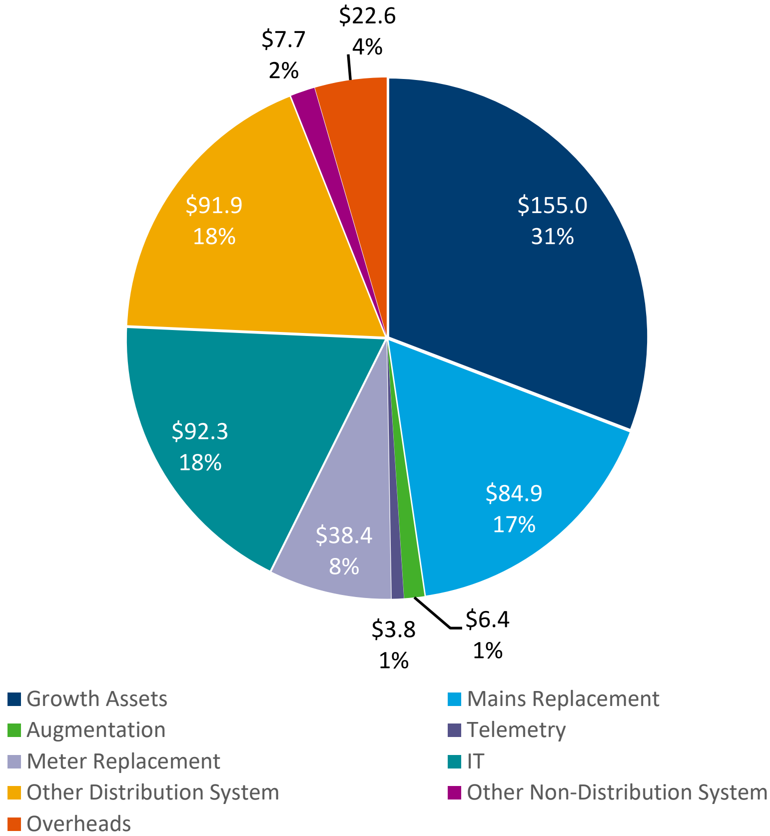
Figure 9.7 provides a breakdown of our forecast capex by driver for the next AA period. As noted above, growth assets accounted for 31% of total capex, reflecting investment required to support the projected new connection to our network. Mains replacement represents 17% of capex, primarily driven by initiatives to maintain mains and service integrity, including MUS renewal and the proactive and reactive replacement of deteriorated protected steel pipelines.

We forecast that 18% of our capex will be in the other distribution system driver category, which includes corrosion management, replacing SCADA equipment to maintain real time pressure and gas flow monitoring. We will also modify DRS facilities to minimise overpressure risks, ensuring compliance with safety and reliability standards.

IT investments make up 18% of capex, incorporating transitioning IT systems inhouse, refreshing business software applications and infrastructure, and strengthening cybersecurity capabilities.

The remainder is distributed across projects and programs supporting ongoing strong safety,

Figure 9.7: Capex by driver over the next AA period ($million, 2025/26))



reliability and service performance.

9.7 How we deliver capex efficiently

We operate within a framework of external and internal controls which govern the way we plan, assess, procure and deliver capital works. This framework ensures we are making sound investment decisions for our customers, our stakeholders and our business.

Our operating context is summarised in Figure 9.8.

9.7.1 Key Business Plans

We have a number of key business plans that govern the scope, timing and approach to undertaking investment in or upgrade of critical business information systems, asset replacement and augmentation works. These investments are necessary to ensure ongoing network safety, that our regulatory obligations are met and that our service performance is maintained in line with our vision objectives. Many of these are endorsed and tracked by the Office of the Technical Regulator (OTR) and the Essential Services Commission of South Australia (ESCOSA).

Our AMS and AMP are key parts of our Asset Management Framework. They outline how our plans are used to drive asset management strategies that are consistent with good industry practice.

Subordinate to the AMS and AMP are:

- the Distribution Mains and Services Integrity Plan (DMSIP) which outlines our approach to managing the integrity of our mains and services and provides the basis for the forecast replacement of mains over the next AA period; and
- the Meter Replacement Plan (also known as the Gas Measurement Management Plan in South Australia) which details our compliance obligations and how this drives the forecast volume of meters to be replaced over the next AA period.

These business plans outline how we continually monitor, evaluate, plan and undertake asset integrity assessments to extend the remaining life, improve, replace, or where necessary, retire assets. This ensures efficient, reliability and safe operations of the network are maintained.

9.7.2 Financial governance

Our business planning doesn't stop with each AA period. We continually update our capex plans to respond to changing business needs.

A key part of our planning is the approval of the capex budget by the Board each year.

Once approved, projects are then managed and monitored through

Figure 9.8: Summary of our operating context

our capital delivery processes, including Executive Leadership Team review of key contracts before they are awarded.

We regularly report our expenditure performance against prior year's spending and approved regulatory allowances. We also regularly review network performance, including through a series of key performance measures as an input into our planning process.

Our Delegation of Financial Authority covers all financial transactions within our organisation. It outlines the level of financial authority at each level within our organisation. Only the CEO has financial delegation to approve funds for unbudgeted initiatives, and only where it fits within the overall approved budget. This provides strong financial controls and governance in the delivery of capex.

9.8 Alignment with our strategic vision in the current AA period

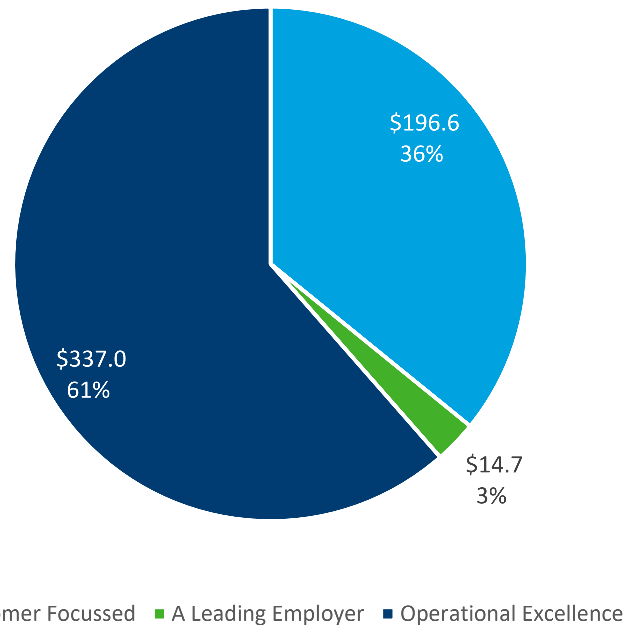
We expect to invest $548 million by the end of this AA period.

Like our capex proposal for the next AA period, our capex in this AA period aligns with AGIG strategic pillars of:

- Operational excellence;
- Customer focussed;
- A Leading Employer; and
- Sustainable Communities.

Figure 9.9 provides a breakdown of the amount of capex we expect to incur against each of these strategic pillars in the current period. As this figure shows, 61% of our capex in the current period is focused on operational excellence and 36% is allocated to customer focussed.

Figure 9.9: Current AA capex forecast by AGIG vision and strategic pillars ($million, 2025/26)



9.8.1 Operational excellence

By the end of the current AA period, we will have invested $337 million on projects and programs that will enable us to maintain operational excellence. We will have replaced over 700km of mains, removing low pressure CI, UPS, first-generation plastic pipes and other identified high risk mains from our network which represents a significant safety milestone for our business. We are also on track to replace all of our highest priority MUS in the current period.

We have undertaken integrity dig ups and surveys, replaced end of life regulators, valves, telemetry and cathodic protection equipment. We have also updated IT applications including geographic information system (GIS) and mobility integration software. In line with our AGIG One IT Strategy, we have replaced the disparate ERP systems with the SAP S/4HANA ERP system, establishing a functional, fully supported, industry-standard system.

9.8.2 Customer focused

We will have invested $197 million in projects that align with our strategic vision of being customer centric. We forecast that we will connect around 37,000 new residential and commercial customers to our network in the current AA period. This investment ensures we continue to meet customer demand while maintaining safe, reliable, and efficient service delivery.

By the end of current AA period, we will have completed the initial phase of planned augmentations in the southern metro network to support residential growth in Seaford and Aldinga. This improves network capacity and ensure the long-term security of supply in these expanding areas. Additionally, we are on track to complete the construction of Gawler Gate Station, a critical infrastructure project designed to increase capacity and strengthen supply reliability across the northern network.

We will invest $21 million to replace approximately 80,000 meters as part of our ongoing meter replacement activities, ensuring precise gas measurement and accurate billing for our customers.

We have successfully launched our customer relationship management (CRM) system, supporting customers experiencing vulnerability, including non-English speakers, individuals with vision impairment and those facing literacy challenges, significantly enhancing our customers' digital customer experience.

9.8.3 A leading employer

We will invest $15 million by the end of the period into the ongoing refresh and replacement of end-user devices, including laptops and mobile phones, office equipment and field devices. This ensures our workforce is equipped with modern, reliable technology, enabling hybrid working arrangements, enhanced staff mobility and greater productivity.

We also will have implemented our Human Capital Management system to deliver a more streamlined and efficient approach to goal setting, performance management and employee training and development. The enhanced system automates compliance tracking, ensuring all employees meet regulatory and safety training requirements. By integrating these critical elements, we are strengthening our commitment to protecting employees and fostering a safe, high-performing work environment for both field and non-field personnel.

9.9 Capex drivers in the current AA period

The following sections provide further detail on the capex drivers and activities we have undertaken in the current AA period.

9.9.1 Mains replacement

Our mains replacement program is the largest driver of our capex in the current AA period. It is the single most important activity we can undertake to ensure public safety.

By the end of the current period, we will have removed all the cast iron, unprotected steel and other identified highest risk low and medium pressure mains from our network. This is a significant safety milestone for our business and delivers against the commitments made to the OTR and our customers.

By the end of the current AA period, we will have replaced over 700 km of mains at a forecast cost of $216 million. This includes 494 km of low pressure cast iron and unprotected steel mains and 190 km of HDPE 250 and HDPE 575 mains.

Additionally, 20 km of HDPE 575 in Port Pirie will be camera inspected instead of replacement. All mains scheduled for replacement or inspection during the current AA period, as agreed with the OTR, will have been addressed. This volume of activity aligns with our commitment to the AER in our last submission.

Furthermore, we will complete inline camera inspection and reinforcements on 364 km of HDPE 575 DN50 with diameters suitable for this activity. These proactive measures will extend the operational lifespan of these mains by an estimated ten years, enhancing network integrity and long-term asset performance.

We will also have renewed 795 Multi-User Sites prioritising those that are highest risk or have known issues (Priority 1).

9.9.2 Meter Replacement

We will continue our existing periodic meter change program to replace older meters, thereby ensuring meter accuracy is maintained. Based on the age and performance of our current fleet of meters, and the metering accuracy requirements we must adhere to, we have replaced around 45,000 meters to June 2024 and forecast we will have replaced a further 35,000 meters by the end of June 2026 at a total cost of $20 million over the five years.

This forecast is in line with our allowance of $23 million and reflects a slightly lower number of replacements being required offset by higher actual unit rate costs incurred for domestic meter replacements. This higher unit rate was driven largely by our suppliers no longer offering refurbished meters during the current AA period, necessitating the purchase of new meters, which are more expensive than refurbished meters.

9.9.3 Augmentation

We augment our network to prevent pressure deterioration, maintain performance standards and ensure reliable service levels for existing customers in growing areas.

By the end of current AA period, we will complete the installation of a gate station in Gawler and establish a new connection to the SEA Gas transmission pipeline. This project will help maintain minimum distribution pressure in the northern section of our network in a cost-effective and sustainable manner, without adversely affecting existing customers.

9.9.4 Telemetry

At the end of the current AA period, we will have invested $2 million to replace obsolete SCADA equipment and upgraded to 4G capable modems. Additionally, we will have installed additional pressure monitoring equipment at strategic locations on the network fringe to enhance our ability to remotely monitor and control the network. These upgrades will ensure the continued reliable collection and transmission of critical operational data, supporting efficient network management as it evolves.

9.9.5 IT System

Our IT systems are fundamental to delivering safe, reliable and efficient services, supporting core business functions such as billing, finance, asset management, operations, regulatory reporting and customer service.

During the current AA period, we will invest approximately $39 million, which expenditure has been focussed on nationalising and consolidating major IT applications, optimising system performance through our application renewal program, strengthening digital capability and undertaking initiatives in line with the AGIG One IT Strategy.

Key programs being carried out over this period include:

- updating our critical IT applications, including our enterprise asset management, GIS, Dial Before You Dig (DBYD) and network mobility systems ensuring they function properly and support safe and efficient network operations;
- completing Stage 1 initiatives of the AGIG One IT Strategy and Roadmap, including implementing our SAP S/4HANA system, enhanced collaboration and communication platforms, enabled economies of scale in operational planning as well as the costs of procuring and supporting IT;
- upgrading outdated and unsupported hardware and network infrastructure to ensure a secure, efficient and fit-for-purpose IT environment; and
- enhancing two-way communication with our customers and uplifting self-service capabilities through the installation of our CRM system and improved website functionality.

9.9.6 Growth

In line with our vision of being customer focused, we will invest $141 million to connect approximately 37,000 new residential and business customers to our distribution network over the current AA period. This includes new homes and businesses in greenfield developments close to our network, new homes and businesses within our network footprint (infill) and existing homes and businesses which are connecting to the gas network for the first time.

9.9.7 Other distribution system assets

We will invest around $57 million in other distribution system assets during the current AA period. This investment will support activities such as ongoing surveys and integrity dig ups, renewing corrosion protection assets at the end of their life, modifying high priority transmission pipeline (TP) to allow inline inspections, replacing inoperable valves, installing regulators on the bypass line for I&C meter sets and at DRS to mitigate overpressure risks in the downstream network and prevent customer disruptions.

Figure 9.10: Corrosion in a valve pit, North Haven

9.9.8 Other non-distribution system assets

We will invest $6 million on other non-distribution system assets in the current AA period. This investment will cover the replacement of small plant and equipment, vehicles and high-pressure flow stopping equipment, driven by the age and condition of these assets, as well as changing business requirements.

9.10 Summary of our capex in the current AA period by driver

Figure 9.11 provides a breakdown of our capex in this AA period by driver. As noted above, a significant portion of our capex in the current AA period is dedicated to our mains replacement program (40%), reflecting our ongoing commitment to ensuring the reliability and safety of our pipeline infrastructure.

Growth capex accounts for 26% which covers the expansion of mains, services and meters necessary to support new residential, commercial and industrial (I&C) customer connections.

Additionally, 10% of our capex is allocated to other distribution system assets and 7% is an IT investment which are crucial for driving digital transformation and enhancing operational efficiency.

The remaining capex is allocated to various projects and programs aimed at ensuring continued compliance with regulatory requirements while upholding our strong focus on safety, reliability and service performance.

Table 9.3 below compares our capex in the current AA period with what we propose to incur in the next AA period by capex driver. It shows that our proposed level of expenditure is lower than what we expect to incur this period. This reduction is largely due to the completion of the low-pressure mains replacement program in the current AA period.

While mains replacement costs will decline overall, higher forecast unit rates for volume driven activities driven by increased regulatory compliance requirements (primarily mandatory traffic control), limited labour market capacity in South Australia and persistent high inflation will erode any volume driven reduction in costs. Additionally, higher IT capex reflects our continued integration into the AGIG One IT environment and the insourcing of our operations.

Distribution system capex will increase due to network modifications to enable ILI and targeted measures to mitigate overpressure risks at DRS, ensuring continued network integrity and safety.

Figure 9.11: Capex by driver in the current AA period ($million, 2025/26)

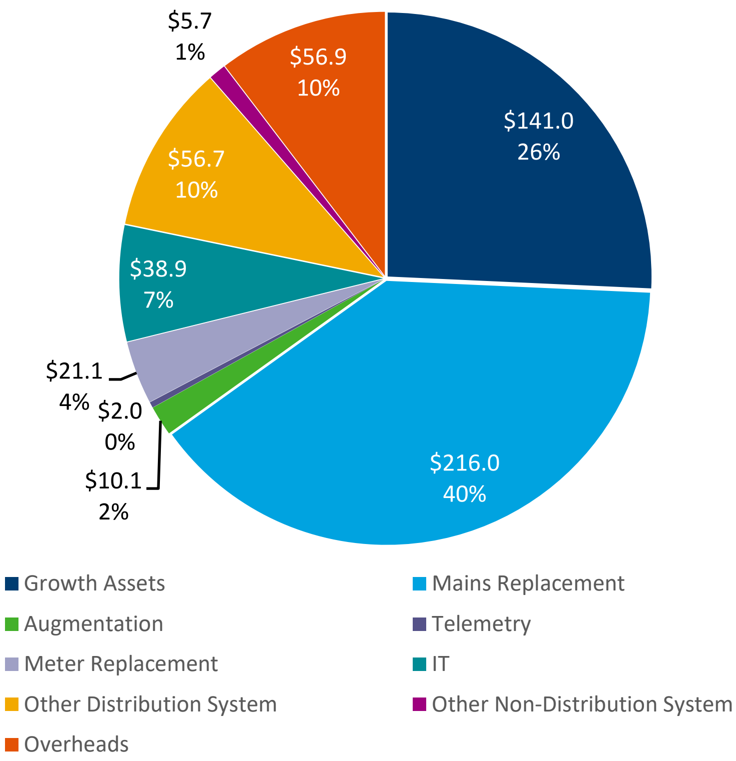


Table 9.3: Forecast capex by driver ($ million, 2025/26)

Driver	Current AA period	Next AA period	Key activities
Growth	141.0	155.0	• Connect new residential and business customers to our network • Extend the distribution network to new areas where it is commercially and economically viable to do so
Mains Replacement	216.0	84.9	• Replace multi-user services (MUS) and protected steel mains Replace older services at multi-user sites (MUS) and protected steel mains • Camera inspections and reinforcement of first-generation HDPE mains
Augmentation	10.1	6.4	• High pressure mains extension in Angle Vale to maintain customer supply pressure while supporting sustained growth • High pressure mains extension and then duplication in the southern metro network
Telemetry	2.0	3.8	• Replacement of end-of-life telemetry equipment • Install additional pressure monitoring equipment
Meter Replacement	21.1	38.4	• Periodic replacement of end-of-life customer meters
IT System	38.9	92.3	• Move to AGIG One IT environment removing duplication across the AGIG group • Maintain existing core business systems • Uplift cyber security and renew IT infrastructure • Deliver an enhanced digital customer service experience
Other distribution system	56.7	91.9	• Corrosion management of steel pipelines • Replace end of life valves, regulators and cathodic protection equipment • Undertake overpressure risk reduction measures for DRS • Modify transmission mains for inline inspection • Network adaption
Other non-distribution system assets	5.7	7.7	• Replacement of small plant and equipment and vehicles
Overheads	56.9	22.6	• Capitalise indirect labour costs for network engineering, technical and compliance services and project & system design
Total	**548.3**	**503.0**	

9.11 Summary

Our capex in the next AA period will ensure we:

- maintain our high levels of public safety and reliability as expected by our customers;
- connect new customers to our network where it is commercially and economically viable to do so; and
- enhance the level of customer service that our customers require and expect.

The projects and programs we intend to deliver are described below:

- continuing our current program to replace services at risk Priority 2 MUS sites and reactively renewing services ($47 million);
- replacing protected steel mains ($32 million);
- camera inspections and reinforcing of ageing HDPE 575 mains ($7 million);
- continuing our meter replacement program ($38 million) to ensure accurate gas measurement and billing for our customers;
- augmenting the southern and northern metropolitan networks ($6 million) to maintain required distribution pressures and services to customers;
- replacing end-of-life telemetry equipment and installing additional network monitoring facilities ($4 million) which is critical to operating and monitoring our network;
- Maintaining and upgrading our operational and corporate applications to ensure IT systems remain current and fit-for-purpose ($24 million), uplift cyber security ($2 million), renewing infrastructure ($3 million), rationalising and integrating the IT environment ($62 million) and delivering digital initiatives that enhance the customer experience and provide overall service improvements ($1 million);
- connecting approximately 34,000 new residential and commercial customers to our network ($155 million);
- modifying our ageing transmission pipelines to allow for inline inspections ($38 million) and other distribution system works such as replacement of valves, over pressure risk reduction, corrosion management of steel pipework ($54 million); and
- replacing and refurbishing of small plant equipment and vehicles, and update leak detection equipment ($8 million).

Our proposed capex in the next AA period is lower than the current period. While the mains and services integrity program will continue at a much smaller scale following the completion of low-pressure mains replacement program, the cost of connecting new residential and business customers is expected to increase due to rising contractor rates and more stringent traffic management requirements.

We are investing more in other distribution system capex and telemetry assets, to enhance steel pipe integrity and corrosion management, continue modifying transmission mains under our ILI initiative, replace ageing valves and regulators, refresh SCADA equipment, and reinforce overpressure protection for DRS.

The uplift in IT investment supports the continued consolidation of IT solutions as part of our AGIG One IT Strategy and the insourcing of our operations once our operational contract ends. This approach minimises operational and cybersecurity risks while achieving economies of scale in IT procurement, support, and operational planning.

These strategic investments will uphold the high levels of public safety and reliability our customers value while driving long term cost efficiencies.

10 Capital base

This chapter discusses the movements in our capital base in the current and next AA period

IN THIS CHAPTER:

- **Our capital base reflects the value of past investments that we have made in the network, but not yet recovered from our customers.**

We are required to adjust our capital base for capex, depreciation and inflation using actual information over the current AA period and forecast information over the next AA period. We estimate that the value of our capital base at the end of the current period will be around $2.1 billion.

10.1 Regulatory Framework

We are required to adjust our capital base to reflect capex (net of any amounts contributed by our customers), inflation and depreciation. We are also required to remove the value of any assets that we have sold and reflect the reuse of redundant assets in the current AA period.

Our forecast of depreciation is required to be set:

- so that our prices vary over time in a way that promotes the efficient growth of the services provided by our business;
- so that our assets are depreciated over their economic life;
- to allow for changes in the expected economic life of a particular asset;
- so that an asset is depreciated only once; and
- to allow for our reasonable needs for cash flow to cover our costs.

10.2 Capital Base as at 1 July 2026

We have adjusted (or rolled-forward) our capital base as at 1 July 2021 with actual capex and inflation and forecast depreciation over the current AA period. We have used forecast information for 2024/25 and 2025/26 as actual information is not yet available.

Table 10.1 shows the adjustments we have made to our capital base over the current AA period. The "funding adjustment" reflects an adjustment for the difference between the forecast and actual capex in the last year of the previous AA period (i.e. 2020/21). Consistent with AER practice, the adjustment reflects the return recovered by AGN that otherwise would have occurred if actual information for 2020/21 were available.

The closing value of the capital base forms the opening capital base for the next AA period.

10.3 Capital Base as at 30 June 2031

This section discusses the forecast adjustments made to the capital base over the next AA period.

10.3.1 Capital Expenditure

Our forecast capex was discussed in Chapter 9 of this Final Plan and is reproduced in Table 10.2, with the capex allocated to the same asset categories used to adjust our capital base. We note that the capex rolled into the capital base includes an amount equal to half a year of return in the year the capex is incurred (and is therefore not the same as our capex forecast in Chapter 9). The AER makes this adjustment to account for the fact that we do not earn a return on the capex within the year it was spent.

Table 10.1: Roll Forward of the Capital Base 2021/22 to 2025/26 ($nominal, million)

	2021/22	2022/23	2023/24	2024/25	2025/26
Opening Capital Base	1,702.0	1,762.9	1,901.8	1,965.2	2,039.4
Less Depreciation	90.7	97.1	110.2	110.7	117.9
Plus Conforming Capex	92.1	97.9	96.6	137.2	99.0
Plus Actual Inflation	59.5	138.1	77.1	47.7	49.4
Less 2020/21 Capex Adjustments	-	-	-	-	-11.7
Less Funding Adjustment	-	-	-	-	-4.7
Closing Value	**1,762.9**	**1,901.8**	**1,965.2**	**2,039.4**	**2,053.6**

Note: Totals may not add due to rounding.

Table 10.2: Forecast Capex 2026/27 to 2030/31 ($nominal, million)

	2026/27	2027/28	2028/29	2029/30	2030/31
Mains	24.4	33.5	25.1	27.6	24.8
Inlets	21.5	21.5	22.2	21.6	20.5
Meters	11.8	10.3	10.1	11.3	12.1
Telemetry	1.3	0.7	0.7	0.6	0.7
IT system	12.3	39.5	12.7	22.5	9.4
Other distribution system equipment	18.0	19.6	19.3	20.3	19.1
Other	3.5	1.1	1.4	1.6	0.5
Total	**92.8**	**126.2**	**91.5**	**105.5**	**87.0**

10.3.2 Forecast Depreciation

We arrive at our Forecast Depreciation for the next AA period as a combination of the outcome of our Future of Gas analysis, described in detail in Chapter 6, and application of the year-by-year tracking approach. The year-by-year tracking approach is the AER's preferred methodology and relies on a set of asset lives that were approved by the AER for the current AA period (as shown in Table 10.3).

As well as the depreciation determined above, we have also applied an additional amount of depreciation as an outcome of the analysis described in Chapter 6. We have applied the additional deprecation to the "Inlets" asset category, as the category reflects pipes that serve individual customer connections.

Table 10.4 shows our forecast straight-line depreciation, which includes the adjusted depreciation.

Table 10.3: Summary of Lives Used to Calculate Depreciation

Asset Category	Standard Useful Life (years)
Mains	60
Inlets	60
Meters	15
Telemetry	20
IT system	5
Other distribution system equipment	40
Other	10
Low Pressure Mains & Inlets / Future of Gas	5

Table 10.4: Forecast Straight-line Depreciation, 2026/27 to 2030/31 ($nominal, million)

	2026/27	2027/28	2028/29	2029/25	2025/26
Straight-line Depreciation	72.6	69.2	81.2	87.9	96.5

Table 10.5: Forecast Regulatory Depreciation, 2026/27 to 2030/31 ($nominal, million)

	2026/27	2027/28	2028/29	2029/25	2025/26
Straight-line Depreciation	72.6	69.2	81.2	87.9	96.5
Less Inflation	54.6	56.7	60.0	62.1	64.6
Regulatory Depreciation	**18.0**	**12.5**	**21.2**	**25.8**	**31.9**

Table 10.6: Forecast Capital Base, 2026/27 to 2030/31 ($nominal, million)

	2026/27	2027/28	2028/29	2029/25	2025/26
Opening Capital Base	2,053.6	2,132.4	2,255.1	2,334.5	2,427.9
Less Depreciation	-72.6	-69.2	-81.2	-87.9	-96.5
Plus Conforming Capex	96.9	135.2	100.7	119.2	101.0
Plus Actual Inflation	54.6	56.7	60.0	62.1	64.6
Closing Value	**2,132.4**	**2,255.1**	**2,334.5**	**2,427.9**	**2,497.0**

Note: Totals may not add due to rounding.

10.4 Forecast inflation

Forecast inflation is a critical element in determining our total revenue and pricing. As explained earlier, forecast inflation is used to adjust the capital base over the next AA period. This forecast is later updated when adjusting the capital base for the previous AA period.

Forecast inflation is also used in determining the total revenue that we can recover (and hence the prices we can charge). This is reflected in the methodology that the AER uses to determine our total revenue, which relies on inflation to determine the following two costs:

- Return on capital – which is calculated by multiplying a nominal rate of return (see Chapter 11) by the nominal capital base determined in this section (where a nominal value includes the impact of inflation); and
- Regulatory Depreciation – which is calculated by deducting from forecast straight-line depreciation (see Table 10.5) the forecast inflation adjustment applied to the capital base.

The AER removes inflation in determining regulatory depreciation to essentially remove the additional compensation for inflation in determining the return on capital, which arises from multiplying a nominal rate of return by a nominal capital base (referred to as a double count of inflation).

10.4.1 Forecast Regulatory Depreciation

Forecast regulatory depreciation is used to determine the total revenue that we can recover over the next AA period. This is calculated as forecast straight-line depreciation that is used to adjust the capital base less the inflation adjustment that is applied to the capital base.

Table 10.5 shows forecast regulatory depreciation that is used to determine assumed total revenue for the next AA period, which as explained has been determined using the AER's preferred approaches to calculating both depreciation and inflation.

10.5 Summary

We have adjusted our capital base over the current and next AA periods to reflect actual/forecast capex, depreciation and inflation.

As noted in the introduction, our Forecast Depreciation is required to be set:

- so that our prices vary over time in a way that promotes the efficient growth of the services provided by our business;
- so that our assets are depreciated over their economic life;
- to allow for changes in the expected economic life of a particular asset;
- so that an asset is depreciated only once; and
- to allow for our reasonable needs for cash flow to cover our costs.

We have achieved this by adjusting the amount of depreciation determined by standard year-by-year tracking approach, by an amount of $30m reflecting as described in Chapter 6.

11 Financing costs

Our single largest cost relates to the cost of financing our $2.1 billion investment in the South Australian natural gas distribution network.

IN THIS CHAPTER:

- **We have followed the 2022 AER's Rate of Return Instrument to estimate the rate of return.**
- **Based on forward market estimates, the rate of return is 6.20% (compared to 4.60% in the current period).**

In this Final Plan, the allowed rate of return and the cost of tax have been calculated according to the AER's Rate of Return Instrument.

Achieving a reasonable rate of return is essential in order to attract the necessary funding from shareholders (through equity) and debt providers to continue to invest in our networks. We are also required to estimate the cost of tax the business will incur over the next AA period.

11.1 Regulatory Framework

The NGL provides a framework for calculating the return on the projected capital base (rate of return). The AER's Rate of Return Instrument (RoRI) details the approach we are required to follow for calculating the rate of return under the NGL.

The RoRI also outlines the AER's methodology for calculating the value of imputation credits (gamma) to equity holders, which is used to calculate the cost of tax building block. Further guidance in respect of the cost of tax is also provided in the AER's December 2018 Tax Review.

We have followed the AER's approach in respect of all aspects of our financing costs and tax allowances.

11.2 Stakeholder engagement

Given the nature of the allowed rate of return, set following the AER's Rate of Return instrument which both we and the AER must follow, the only consultation undertaken in respect of the rate of return was to explain the framework and, where relevant, explain how this building block impacted prices.

11.3 Financing Costs

Our financing costs are determined based on an estimate of the return on equity and the return on debt over the next AA period, which are together referred to as our rate of return and are discussed in this section.

11.3.1 Return on Equity

The return on equity reflects the return required by shareholders to invest in the network. Unlike the return on debt, it is not possible to observe the return on equity required by shareholders in the market. This means that we are required to use financial models and other market evidence to inform an estimate of the return on equity required by shareholders.

The AER estimates the return on equity using the Capital Asset Pricing Model, which requires the following three parameters to be estimated:

- The risk free rate – which measures the return an investor would expect from an asset with no risk. It is estimated based on the interest rate on Australian Commonwealth government bonds with a 10-year term, measured over a 20-day averaging period prior to the commencement of the AA period;
- The Market risk premium– which reflects the expected return over the risk-free rate that investors require to invest in a well-diversified portfolio of risky assets (also assumed to be a 10-year term); and
- Equity beta – which measures the sensitivity of a business' returns relative to movements in the overall market returns (systematic or market risk).

We have applied the AER's 2022 RoRI, which results in a return on equity of 8.01% over the next AA period (see Table 11.1).

These values are indicative and were measured using recent information available prior to the release of this Final Plan. The AER will update market values when it makes its Final Decision.

Table 11.1: Indicative return on equity

Parameters	
Equity risk-free rate	4.29%
Beta	0.6
Market Risk Premium	6.20%
Return on equity	**8.01%**

11.3.2 Return on Debt

The return on debt reflects the interest rate required by debt holders on issued debt (or the interest rate on our loans). Much like the return on equity, the return on debt can be thought to comprise a base interest rate and a risk premium, in this case referred to as the debt risk premium (DRP).

The return on debt is measured as a 10-year trailing average, with each "tranche" (equal to one-tenth of the debt portion of our RAB) being updated annually.

The return on debt for each tranche is formed as a weighted average of A-rated debt indices (one-third weight) and BBB-rated debt indices (two thirds weight). The third-party indices that are used to provide the required debt information are provided by the Reserve Bank of Australia, Bloomberg and Thomson Reuters.

Unlike the return on equity, the return on debt is updated annually and, once calculated, the cost of debt for a given tranche remains in place for ten years. This assumes that we refinance our debt equally over a 10-year period.

Applying the AER's RoRI yields an average return on debt of 4.99%, which we have applied in this Final Plan.

11.3.3 Rate of Return

The AER assumes that 60% of our total financing costs relate to debt with the remaining 40% relating to equity. Applying these percentages to the return on equity (8.01%) and return on debt (4.99%) results in an overall average rate of return of 6.20% in the next AA period.

11.4 Cost of Tax

We have reflected the outcomes of the AER's December 2018 Tax Review in this Final Plan. Our cost of tax building block is based on an assessment of our taxable income, the applicable corporate tax rate and the value of imputation credits (gamma) to equity holders. These matters are discussed in this section.

The result of following the AER's approach to tax is that our tax building block is zero over the next AA period.

11.4.1 Calculating the Cost of Tax

We have determined the cost of tax as total revenue less opex, tax depreciation and interest expense; where:

- Total revenue – is the sum of all of our costs (or building blocks) (see Chapter 14);
- Opex – is a specific building block that is used to determine total revenue (see Chapters 8 and 14);
- Tax depreciation – is based on the calculation of the tax asset base in any particular year; and
- Interest expense – is determined by multiplying the cost of debt by 60% of our capital base in each year, reflecting the debt funded portion of the capital base.

The corporate income tax rate is set at 30% consistent with the prevailing corporate tax rate applying in Australia. The value of imputation credits (or gamma), like tax depreciation, is a specific input that is required to determine the cost of tax.

11.4.2 Value of Imputation Credits

The value of imputation credits (or gamma) is 0.585 as determined in

Table 11.2: Roll forward of the tax asset base ($million, nominal)

	2026/27	2027/28	2028/29	2029/30	2030/31
Opening tax asset base	1,316.6	1,305.9	1,330.2	1,300.4	1,290.9
Plus gross capex	95.3	133.0	99.0	117.1	99.2
Less tax depreciation	-106.0	-108.6	-128.8	-126.7	-133.5
Closing tax asset base	**1,305.9**	**1,330.2**	**1,300.4**	**1,290.9**	**1,256.5**

Note: totals may not add due to rounding

the AER's 2022 RoRI. The effect of gamma is to reduce any tax allowance by 58.5%.

11.4.3 Tax Depreciation

Tax depreciation is used to determine the estimate of taxable income and to update the value of our Tax Asset Base (TAB). Our approach to determining tax depreciation is consistent with that applied in the previous AA and the AER's requirements.

11.4.4 Tax Asset Base

The opening TAB of $1,318 million ($nominal) as at 1 July 2026 has been adjusted for the same forecast information used to adjust our capital base over the next AA period (see Table 11.2).

11.5 Summary

Our financing and tax costs collectively account for around 52% of our total costs. For the purposes of this Final Plan, we have applied the AER's Rate of Return Guideline and the AER's Tax Review in determining our financing and tax costs.

This results in an average rate of return of 6.20% (see Table 11.3) and a Net Tax Allowance of $0 million.

Table 11.3: Indicative AER Rate of Return

Parameters	AGN Draft Plan
Return on Equity	8.01%
Return on Debt	4.99%
Overall Rate of Return	6.20%
Gamma	**0.585**

12 Incentives

Our incentive schemes ensure that we operate efficiently in respect of both our capital and operating expenditure.

IN THIS CHAPTER:

- **Based on our current AA period opex performance, we have forecast a negative Efficiency Carryover Mechanism (ECM) estimate of $9.3 million for the next AA period.**
- **At the same time, our forecast capex performance suggests a positive Capital Expenditure Sharing Scheme (CESS) carryover of $17.4 million.**
- **We propose continuation of both schemes in the next AA period.**

We support the use of effective, outcome-based incentive schemes that promote the long-term interests of our customers.

Incentive schemes are often used by regulators to:

- strengthen a service provider's incentive to continuously seek out efficiency and performance improvements and share the benefits with customers;
- provide balanced incentives between opex and capex so that the most efficient expenditure mix is chosen;
- balance the incentives to pursue efficiencies and to improve or maintain service quality; and
- provide an incentive to invest in innovation in areas that can provide longer-term benefits to customers.

In the current period, the incentive schemes that apply to our South Australian network are the opex Efficiency Carryover Mechanism (ECM) and the Capital Expenditure Sharing Scheme (CESS).

The following sections provide further detail on regulatory requirements for the incentive schemes, our stakeholder consultation on our existing schemes, our forecast scheme carryover outcomes for the next AA period and how we propose to continue the schemes into the next period.

12.1 Regulatory framework

A key objective of the regulatory framework is to promote efficient investment in the operation and use of gas distribution networks.

In keeping with this objective, the NGR provides for gas networks to have one or more incentive schemes applying to encourage the efficient provision of services.

The NGR also requires any incentive mechanism to be consistent with the revenue and pricing principles, the most relevant of which is the principle that a service provider should be provided with effective incentives to promote:

- efficient investment in (or in connection with) the network;
- the efficient provision of services; and
- the efficient use of the network.

Table 12.1: Summary of customer and stakeholder engagement on our incentive schemes

Topic	Customer and Stakeholder Feedback	Our Response
Incentive Scheme	**Stage 1 & 2 Engagement: Developing our Plans**	
	• Our customers told us that they were broadly comfortable that the current framework regarding the Efficiency Carryover Mechanism (ECM) and the Capital Expenditure Sharing Scheme (CESS) appropriately incentivises us to incur only efficient opex and to spend efficiently on capital projects.	• During Stage 2 of our stakeholder engagement program, we held SARG and RRG meetings to engage on key areas of our plan, including our proposed continuation of the EBSS and CESS incentive schemes for the next AA period.
	Stage 3 Engagement: Draft Plan Consultation • **Do you support our proposal to maintain the opex efficiency carryover mechanism (ECM)?** • **Do you support our proposal to maintain the capital expenditure sharing scheme (CESS)?**	
	• Stakeholders continued to indicate broad agreement for the ECM and CESS to apply in the next AA period with no concerns identified.	• We presented at our reference group meeting the key opex and capex drivers in the current AA period, including the higher cost environment. • We shared our preliminary incentives forecast for the current AA period.
	Stage 4 Engagement: Refining our Plans	
	• SARG support the continued application of the EBSS and the CESS in the next AA period. • No further feedback was received.	• Our proposals relating to incentives are included in this chapter.
	Final Plan Outcome	
	The Final Plan includes a continuation of the opex incentive mechanism (EBSS) and the capex sharing mechanism (CESS) that currently apply for our South Australian network.	

12.2 Customer and stakeholder engagement

In our reference group meeting in February 2025, we shared our plan to continue the application of the ECM and CESS schemes to our expenditure for our SA network, which were otherwise supported by stakeholders, and included in our Final Plan.

In response, stakeholders indicated support for the continuation of the two incentive schemes into the next AA period, as noted in Table 12.1.

We did not receive any feedback to suggest any additional incentive schemes, and this reflects our position in our Final Plan to continue with the ECM and CESS schemes only.

12.3 Opex ECM

Our South Australian network is currently subject to an opex ECM and we are proposing to continue to employ this incentive scheme in the next AA period.

The opex ECM, which is a key element of our opex forecasting approach (see chapter 8) [1], is designed to provide us with a continuous incentive to pursue opex efficiency improvements in any particular year of an AA period and to share any efficiency gains (or losses) with our customers.

The ECM operates in a symmetric manner, which means that we are rewarded if there is an incremental efficiency gain, and penalised if there is an incremental efficiency loss.

To ensure that we have an incentive to pursue efficiency gains evenly throughout the AA period, we retain the benefit of any efficiency gain (or incur the cost of any efficiency loss) for five years. After the relevant AA period, the benefit (cost) is passed through to our customers in the following AA period.

In effect, this scheme provides for 70% of the efficiency gains (or losses) to be passed through to our customers in the form of higher (lower) prices and we retain the remaining 30%.

The revenue adjustment in the next AA period as a result of the ECM (and efficiency gains achieved/losses incurred) in the current AA period is provided in Table 12.2 and again in the building block revenue calculation in Chapter 14.

12.3.1 Where it is used

An opex ECM or similar is also in place on all other gas and electricity distribution and transmission networks regulated by the AER.

The AER's 2023 review of incentive schemes found that the opex incentives schemes are working as intended with the benefits to consumers up to four times the benefits to network service providers.[2]

Prior to the current AA period, we calculate the scheme has delivered almost $290 million in benefits to our customers since its introduction.

12.3.2 ECM forecast for the current period

We are forecasting an efficiency carryover of negative $9.3 million in the next AA period from the operation of this scheme in the current AA period. The negative carryover is mainly the result of our opex estimate for 2024/25 exceeding the benchmark. This carryover provides a benefit to our customers through our reduced revenue allowance, which offsets the increase in our base year opex.

Table 12.2: Summary of revenue adjustments in the next AA period for incentive schemes operating in the current AA period

$m 2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	Total AA
Opex ECM	4.8	(5.5)	(4.2)	(4.3)	-	(9.3)
Contingent CESS	3.5	3.5	3.5	3.5	3.5	17.4
Total	**8.2**	**(2.1)**	**(0.8)**	**(0.8)**	**3.5**	**8.1**

[1] Our opex forecasting approach relies on actual incurred opex in the penultimate year of an AA period being efficient.

[2] AER, *Final decision – review of incentive schemes for networks – 28 April 2023*, p 5.

12.4 Capex CESS

While we have had an opex ECM in place for a long period of time, we have only had an equivalent capex incentive scheme in place for the current AA period.

The CESS mirrors the 'Contingent CESS' that was also adopted by the AER for our Victorian and Albury networks.

The 'Contingent CESS' was introduced in Victoria from the commencement of the 2018-2022 Access Arrangement period, following an extensive industry engagement program that included stakeholder representatives and gas distributors at a national level, not just Victoria.

12.4.1 How the CESS works

In a similar manner to the ECM, the CESS provides us with a continuous incentive to pursue capex related efficiency improvements over the AA period and to share any efficiency gains (or losses) with our customers.

The CESS also:

- reduces inefficient growth in our capital base by providing a greater incentive to incur efficient capex; and
- addresses the imbalance in incentives that currently apply to decisions regarding whether opex or capex should be undertaken.

Under the Contingent CESS, 70% of any incremental capex[3] efficiency gains (or losses)[4] we achieve are passed on to our customers, subject to the following:

- our ability to retain 30% of the efficiency gain would be contingent on us maintaining service standards and the health of the network, which is measured using an Asset Performance Index (API) (see Box 12.1); and
- if we defer capex from one AA period to the next, the efficiency gain would is reduced.

These elements of the CESS are designed to ensure that cost savings are achieved through efficiency improvements, not reduced service levels, or an inefficient deferral of capex.

12.4.2 Where it is used

As noted above, the AER has allowed a 'Contingent CESS' to be applied to all gas distribution networks in Victoria, South Australia and Jemena's NSW gas distribution network. A form of the CESS also applies to the electricity distribution and transmission networks regulated by the AER.

Box 12.1: Asset Performance Index

The API is used in the contingent CESS to determine how much of the efficiency gain we are able to retain. This metric reflects both:

- service performance, as measured by the unplanned system average interruption frequency index (SAIFI) and unplanned system average interruption duration index (SAIDI); and
- the health of the network, as measured by number of reported leaks in gas mains, services and meters.

In our South Australian networks, the AER set targets for each of these measures based on the five-year historical performance of each network. If we meet or exceed these targets, we can retain 30% of the efficiency benefit. If, however, we do not meet these targets, the benefit can be reduced on a sliding scale, potentially to zero (i.e. if we fall below 80% of the target).

[3] The CESS applies to capex, net of contributions and disposals, and adjusts for material deferrals, the effect of ex post capex reviews and cost pass throughs.

[4] These benefits and costs must be adjusted for any financing benefits or costs.

12.4.3 The Asset Performance Index

We propose the same performance measures and the same approach to setting the targets as the AER applied for our network in 2021. Specifically:

- Performance measures: unplanned outages and duration and mains, services and meter leaks; and
- Targets: average of last five years performance, with unplanned outages and duration weighted at 25% each and mains, services and meter leaks making up the other 50% of the index based on their relative share of our asset base when the scheme was first introduced.

Table 12.3: Asset performance index measures, targets and weightings

Measure	Target	Weight
Unplanned SAIFI	0.59	25%
Unplanned SAIDI	307.04	25%
Mains leaks	0.11	42.4%
Service leaks	3.76	4.9%
Meter leaks	12.35	2.7%

The targets and weightings for each of these measures that will apply in the next AA period are shown in Table 12.3. The targets have been reset based on most recent actual performance (2021-2026).

12.4.4 CESS forecast for the current period

We are forecasting an efficiency carryover of positive $17.4 million in the next AA period from the operation of this scheme in the current AA period. The combined impact of both the CESS and ECM is for a carryover amount of $8.1 million in our proposed revenue allowance for the next AA period.

12.5 Summary

In the next AA period, we are proposing to continue the application of the ECM and CESS incentive schemes to pursue efficiencies and to continue to share the benefits with our customers.

13 Demand

Our customers' overall demand for gas is expected to decline in the next AA period in line with recent trends.

IN THIS CHAPTER:

- **Our demand forecasts have been independently determined, applying methodologies which were approved previously by the AER, consistent with past trends.**
- **Overall demand for gas in the residential, commercial and industrial sectors is expected to fall, also consistent with past trends.**

The demand for our services drives our operations and is a key determinant of our prices.

Our forecasts of gas demand and customer numbers are key inputs to our growth capex and opex forecasts. They are also used to determine our prices (reference tariffs), which are calculated by dividing our forecast revenue requirement by forecast demand.

Reflecting the differences in the nature of demand for our services, separate demand and customer connection forecasts have been developed by independent expert Core Energy & Resources ('Core Energy'), for our:

- Residential sector;
- Commercial sector (business customers who use less than 10 terajoules of gas each year); and
- Industrial sector (our largest business customers).

These market sectors are consistent with our proposed Haulage Reference Services to be provided over the next AA period.

In the next AA period, Core Energy forecasts the demand for natural gas for the:

- residential sector to fall by 5.3% per year, in response to a range of external factors, such as higher wholesale gas prices, improved appliance and dwelling efficiency, impacts of policy favouring electrification and negative sentiment towards gas, fewer new connections than recent history and more disconnections from the network;
- commercial sector to fall by 1.1% per year, largely due to higher wholesale gas prices, improved appliance efficiency, electrification, less new connections and more disconnections from the network; and
- industrial sector to fall by 1.3% per year, which reflects an accelerating long-term trend in response to higher wholesale gas prices, lower economic activity and increasing efficiency.

Overall, Core Energy projects that the demand for gas by our customers will fall by 2.4% per year in the next AA period, which falls between AEMO's current Progressive and Step Change scenarios for South Australia.

The following sections provide more detail on the relevant regulatory framework, the forecasting method and the demand forecasts themselves.

13.1 Regulatory framework

Our AA proposal must include the forecast demand for reference services. In keeping with the NGR, these forecasts must:

- be arrived at on a reasonable basis; and

- represent the best forecast possible in the circumstances.

The AER also identified a number of principles of best practice for demand forecasting in its Better Regulation program. The AER concluded that forecasts should:

- be accurate and unbiased;
- be transparent and repeatable;
- incorporate key drivers;
- incorporate a suitable method of weather normalisation; and
- be subject to statistical model validation and testing.

In previous AA reviews, the AER's consultants have assessed Core Energy's forecasts against these principles and concluded that the Core Energy forecasts were consistent with the above principles.

13.2 Customer and Stakeholder engagement

We engaged with stakeholders (including retailers and our customers) in respect of our demand forecasts. At our SA Reference Group meetings and Retailer Reference Group meetings, we discussed the approach and the importance of understanding key drivers of future demand.

Stakeholders indicated they understood our approach to forecasting residential, commercial and industrial demand and noted that the approach is consistent with that adopted for our recent reviews, including our last SA review. Stakeholders were comfortable with the approach to forecasting demand.

In particular, retailers indicated that trends shown in demand forecasts are consistent with their own observations and expectations of demand.

Stakeholders questioned whether demand forecasts and assumptions should be more explicitly linked to investment decisions and risk mitigation strategies. We believe that in the South Australian jurisdiction, whilst the forecast of new connections is lower in the next AA period relative to the current AA period, there is ongoing

Figure 13.1: Forecasting method used for residential and commercial customers

Step 1
Normalise historic data

1. Normalise the historic demand per connection data for both residential and commercial customers to remove fluctuations due to weather.
2. Use the normalised data to calculate an historic annual average growth in demand per connection.
3. Adjust for the effect of energy price changes from the historic growth.

Step 2
Forecast demand per connection

Determine the forecast demand per connection by adjusting the normalised data in Step 1 to account for drivers that are not reflected in the historic data, i.e. future energy price movements.

Step 3
Forecast connections

Derive a forecast of the net connections that will occur in the next AA period for residential customers (largely based on forecast new dwelling growth) and commercial customers (largely based on forecast economic activity).

Step 4
Forecast demand

Determine the forecast demand for both residential and commercial customers by multiplying the forecast consumption per connection from Step 2 by the total forecast connections for each customer group from Step 3.

Table 13.1: Summary of customer and stakeholder engagement on demand

Topic	Customer and Stakeholder Feedback	Our Response
Demand	**Stage 1 and 2 Engagement: Developing our Plans**	
	• We did not consult with our customers during workshops on our approach to demand forecasting. • Members of our South Australian Reference Group and Retailer Reference Group showed an interest in our demand history and forecasting.	• At many of our SA Reference Group meetings and Retailer Reference Group meetings, we discussed the approach and the importance of understanding key drivers of future demand and our forecasting approach.
	Stage 3 Engagement: Draft Plan Consultation • **Do you support our approach to forecasting demand?** • **Are there any other factors we should consider in developing our demand forecasts?**	

	• SARG members would like AGN to test the demand forecasts against multiple policy and technology scenarios, such as:
	  ○ South Australia adopting a Victorian-style gas substitution roadmap.
	  ○ Hydrogen and biomethane not becoming commercially viable within the forecast period.
	• Stakeholders believe demand forecasts and assumptions should be more explicitly linked to investment decisions and risk mitigation strategies (e.g. accelerated depreciation).
	• Stakeholders would like AGN to explain how demand projections interact with long-life capex and pricing over time, especially post-2031.
	• Stakeholders note and acknowledge decline in demand.
		• We invited SARG and RRG members to a Deep Dive on demand forecasting to address their questions and concerns.
		• Core Energy is forecasting demand in between AEMO's step change and progressive scenarios.
		• If connections don't materialise, the capex will not be incurred – this is the main link between the demand and capex forecasts.
		• If there's a policy change, we would respond by reopening the Access Arrangement, adjusting demand down, and potentially increasing depreciation as risks would change.
		• Hydrogen and biomethane not becoming commercially viable within the forecast period would not impact the demand forecast in the next period but would in subsequent periods.

	Stage 4 Engagement: Refining our Plans	
	• We surveyed our South Australian major users to better understanding their gas usage over the coming five-year period.	• Our proposals relating to demand are included in this chapter.
	Final Plan Outcome	
	Core Energy is forecasting demand in between AEMO's step change and progressive scenarios. If connections don't materialise, the capex will not be incurred – this is the main link between the demand and capex forecasts. If there's a policy change, we would respond by reopening the Access Arrangement, adjusting demand down, and potentially increasing depreciation as risks would change. Hydrogen and biomethane not becoming commercially viable within the forecast period would not impact the demand forecast in the next period but would in subsequent periods.	

consumer demand to connect to the gas network. To the extent there is a change in policy which affects demand, whether that be through a restriction of customer ability to choose gas appliances or a form of gas connection moratorium, we can amend demand forecasts, growth capex any other required changes to our plans prior to the AER's Final Decision next year. In the event such policy is implemented post commencement of the next AA period our preference is to manage within the settings of the AER's Final Decision, however the option to re-open the Access Arrangement within period remains if the impact is material.

Stakeholders also asked us to consider the demand forecasts within the context of multiple policy and technology scenarios, such as:

- South Australia adopting a Victorian-style gas substitution roadmap;
- Hydrogen and biomethane not becoming commercially viable within the forecast period;
- How demand projections interact with long-life capex and pricing over time, especially post-2031.

A consideration of the impacts of such potential outcomes is provided in Chapter 6 and associated attachments.

We have continued to refine our demand forecasts, including conducting a survey with our major SA industrial users to better understand their future demand requirements, including any planned connections or disconnections over the next AA period.

13.3 Residential and Commercial Demand

The method that Core Energy has used to forecast demand and connections for the residential and commercial sectors is broadly the same, reflecting the fact they share the common key drivers of weather and gas price. The forecasting method that Core Energy has employed for our residential and commercial customers is therefore discussed jointly below.

13.3.1 How our forecasts were developed

The method Core Energy has used to forecast our residential and commercial customers' demand is summarised in Figure 13.1.

The method summarised in Figure 13.1 is consistent with the approach that was used to develop the demand forecasts for the current AA period for both our South Australian, and Victorian and Albury networks, which were approved by the AER.

It is also consistent with the principles employed by the Australian Energy Market Operator (AEMO), when forecasting residential and small commercial demand for its Gas Statement of Opportunities.

The energy transition, combined with numerous other factors, has dampened gas demand in recent times, with this trend set to continue. This means that the methodology that Core Energy utilises may not produce a forecast which accurately predicts gas demand going forward without consideration of intangible factors such as the impact of consumer sentiment driven by concerns around climate change, which concerns are reflected in an electrification assumption, combined with the cost of living crisis. These new influences are affecting gas demand in ways not observed in the past. Core Energy's methodology necessarily not only is consistent with AEMO's forecasting principles, it includes reference to AEMO's forecasts and assumptions to ensure that these factors are taken into account, to produce the best possible forecast in the circumstances.

Further detail on some of the key elements of this methodology is provided below.

Weather adjustment

Our residential and commercial customers' demand for gas is strongly affected by weather, with customers using more gas when it is colder to heat their homes and businesses and vice versa in warmer weather. An adjustment for weather must therefore be made to historic residential and commercial demand to ensure the starting point and historic trends used to forecast gas demand are not unduly affected by abnormal weather conditions (see Step 1.1 in Figure 13.1).

The adjustment Core Energy has made is based on the same approach that is used by AEMO, which is referred to as the Effective Degree Day (EDD312) weather standard. This approach enables us to determine the volume impact attributable to annual variances to weather relative to the EDD baseline.

This volume impact is then removed from the historic consumption per connection trend to derive a weather normalised trend that can be used for forecasting purposes.

Forecast new dwelling growth

The number of new residential connections expected over the next AA period is directly related to the forecast number of new dwellings in South Australia.

This aspect of Core Energy's forecast is based on an independent forecast of new dwelling commencements by the Housing Industry Association (HIA) (see Figure 13.2).

As Figure 13.2 shows, HIA has projected growth in both detached houses and multi-unit dwellings in the first half of the next AA period, after which the number of housing commencements drop steeply, partially offset by more multi-unit dwellings. The peak in commencements was observed during 2021 and 2022 due to the federal government's housing stimulus during that period.

13.3.2 Residential demand forecast

Using the methodology set out above, Core Energy has developed an early forecast of residential demand in the next AA period by multiplying the forecast number of residential connections by forecast consumption per connection.

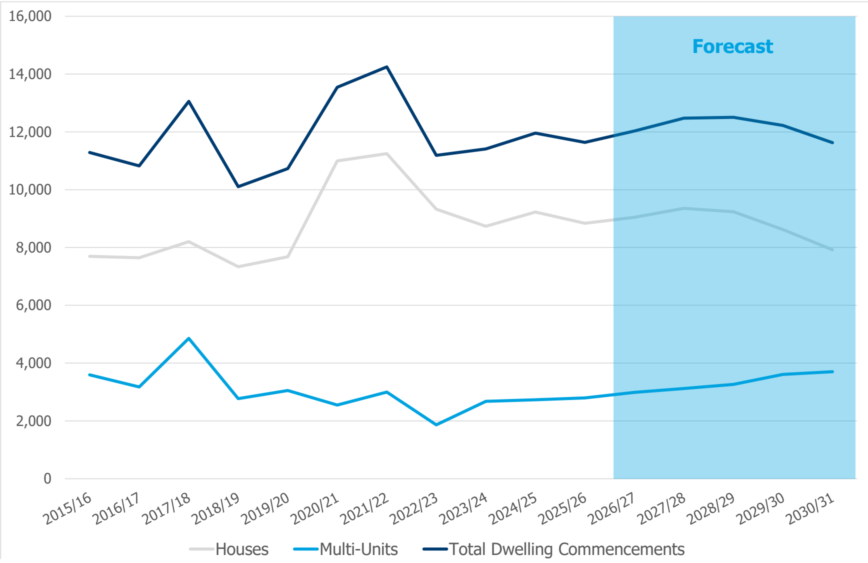
Residential connections

Core Energy is projecting that our residential connections will grow by 0.3% per year in the next AA period, reaching 484,172 by the end of the period.

The forecast growth in residential connections is lower than the 10-year historic average growth rate of 1.2% per year. This is due in large part to:

- a drop in new dwellings forecast in the latter half of the next AA period (see Figure 13.2), due to lower forecast population growth;
- housing stimulus during the pandemic ending;
- an increase in all electric dwellings and new housing estates;
- a lower penetration rate observed in the last five to seven years, driven by the emergence of all electric developments and cost of living pressures; and
- an increase in the number of disconnections, particularly at the decision point where household appliances reach the end of their useful life.

Figure 13.2: HIA actual and forecast dwelling commencements in South Australia



Consumption per connection

Core Energy is also forecasting that consumption per residential connection will fall by around 5.5% per year over the next AA period, from 12.9 GJ in 2025/26 to 9.7 GJ in 2030/31.

As Figure 13.4 shows, this fall is consistent with the long-term decline in average residential consumption per connection that has occurred over the past 15 years. In 2008/09, the average consumption per connection was 20.6 GJ, however by 2023/24 it was 13.8 GJ. This decline is also being observed in other gas distribution networks.

The key drivers of this decline include:

- improved appliance and dwelling efficiency;
- the growing trend of the substitution of gas appliances for their electric equivalent (for example, substituting gas heating for electric reverse cycle air-conditioning);
- a forecast increase in the construction of multi-unit dwellings which consume far less gas than detached dwellings;
- the expected increase in wholesale gas prices over the period; and
- improvements in construction standards as required by the update to the National Construction Code in 2022 which has improved the thermal efficiency of new housing stock; and
- new connections consuming around 20% less gas on average than historical connections due to lower

average dwelling size and appliance efficiency.

Reflecting these evolving trends, Core Energy's forecast sits in between AEMO's Progressive and Step Change scenarios.

Due to these changing household gas usage patterns, we surveyed 400 of our South Australian customers in May 2025 to further understand this change (see Attachment 13.4). It found cost of living pressures are a significant driver of reduced gas usage, with many customers reporting they are seeking more energy independence through the purchase of solar panels and batteries. Customers also said that gas is not perceived as affordable, which contributes heavily to their reduced usage.

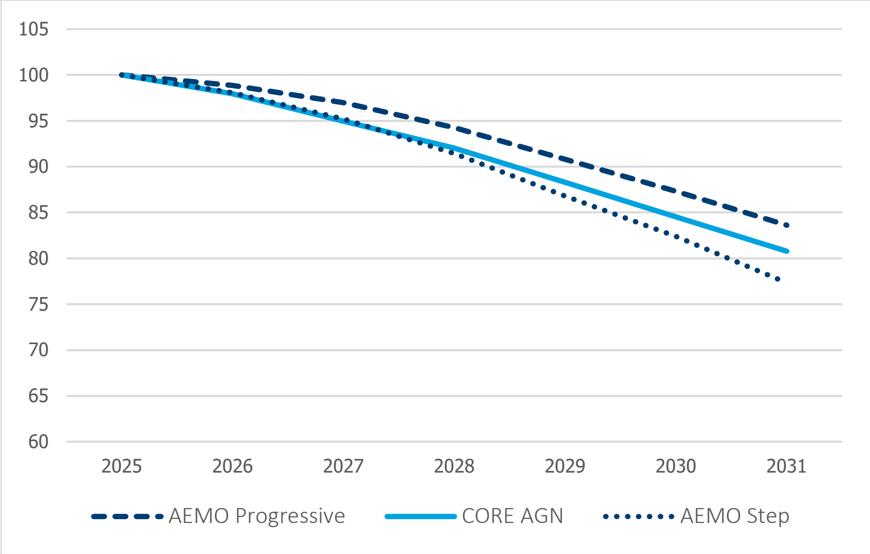
Of customers that have reduced their usage, 23% have disconnected at least one gas appliance in the past year, and are more likely to have space heating connected which is the biggest driver of gas usage in the home. Many are deliberately changing their habits around gas consumption and energy consumption more broadly, e.g. reducing showering and space heating. Many users reported that they intend to continue to reduce their gas use going forward.

Total residential demand

Overall, the demand for gas by our residential customers in the next AA period is expected to fall by 5.3% per year from 6,144TJ in 2025/26 to 4,689TJ in 2030/31 (see Figure 13.4 and Table 13.2).

This fall reflects the effect of the forecast decline in consumption per residential connection which is partially offset by growth in residential connections.

Figure 13.3: Comparison of Core's forecast to AEMO Progressive and Step Change Scenarios



13.3.3 Commercial demand forecast

Like residential demand, Core Energy's commercial demand forecast is calculated by multiplying the forecast number of commercial connections by the forecast consumption per commercial connection.

Commercial connections

In the next AA period, Core Energy is projecting the number of commercial connections (net of disconnections) will grow by -0.1% per year reflecting recent trends in new connections and disconnections. This flat growth is driven by a combination of lower forecast new commercial developments combined with a higher forecast level of disconnection from the network.

Consumption per connection

In a similar manner to our residential customers, the average consumption per commercial connection is expected to decline in the next AA period, primarily as a result of higher wholesale gas prices leading to higher retail bills, thereby dampening demand.

Other factors include the penetration of battery storage usage in small businesses, advances in energy efficiency.

The decline is not, however, expected to be as pronounced as it is for our residential customers due to the slower historic trend decline in consumption per connection, with consumption per commercial customer forecast to fall by 1.1% per year over the next AA period from 272 GJ in 2026/27 to 259 GJ in 2030/31.

Total Commercial demand

The total demand for gas from commercial customers is expected to decline by 1.1% per year over the next AA period, from 3,132TJ in 2026/27 to 2,981TJ in 2030/31 (see Figure 13.8 and Table 13.2).

13.4 Industrial demand

13.4.1 How our forecast was developed

- In contrast to residential and commercial customers, our industrial customers are charged on the basis of the maximum capacity they are expected to require on a day. The forecast demand for this group is therefore based on both: the maximum amount of capacity that our industrial customers are expected to require on a day (referred to as Maximum Daily Quantity (MDQ)); and

- the total amount of gas that are our industrial customers are expected to consume in a year (referred to as Annual Contract Quantity (ACQ)).

To help inform this forecast, we have conducted a survey of our top industrial customers, the objective of which is to better understand their future MDQ and ACQ requirements, including any planned connections or disconnections over the next AA period. We received three responses to the survey which informed the forecast in relation to those customers.

For those customers that did not respond to the survey, Core Energy will examine the relationship between each customer's historic demand and economic activity. In those cases where there is a statistically significant relationship, the MDQ and ACQ is forecast by applying an adjustment to the historic demand based on forecast economic growth.

In those cases where there was not a statistically significant relationship, the MDQ and ACQ is forecast by applying an adjustment based on the historic trend.

The connections forecast for industrial customers has been developed having regard to historic growth estimates and information on known new connections and disconnections.

13.4.2 Industrial demand forecast

Industrial MDQ is forecast to decline by 1.3% per year to 47,182 GJ MDQ over the next AA period (see Figure 13.11). Industrial connections are also forecast to decline to 107 connections, from 112 at the start of the AA period.

13.5 Summary

Table 13.2 provides a summary of our demand forecasts for the next AA period.

As this table shows, residential, commercial and industrial demand are all forecast to decline over the next AA period.

Our demand forecasts are based on the methodology accepted by the AER in the current AA period for both our South Australian, Victorian & Albury networks.

Table 13.2: Summary of demand forecast

	2026/27	2027/28	2028/29	2029/30	2030/31
Residential demand					
Connections (closing)	477,264	476,823	479,878	482,411	484,172
Consumption per connection (GJ)	12.3	11.8	11.1	10.3	9.7
Demand (TJ)	5,885	5,633	5,309	4,993	4,689
Commercial demand					
Connections (closing)	11,528	11,532	11,528	11,508	11,485
Consumption per connection (GJ)	272	269	267	263	259
Demand (TJ)	3,132	3,104	3,073	3,032	2,981
Industrial demand					
Connections (closing)	111	110	109	108	107
MDQ	50,106	49,706	49,155	48,303	47,182
ACQ (TJ)	9,663	9,593	9,497	9,350	9,158

Figure 13.4: Residential Connections

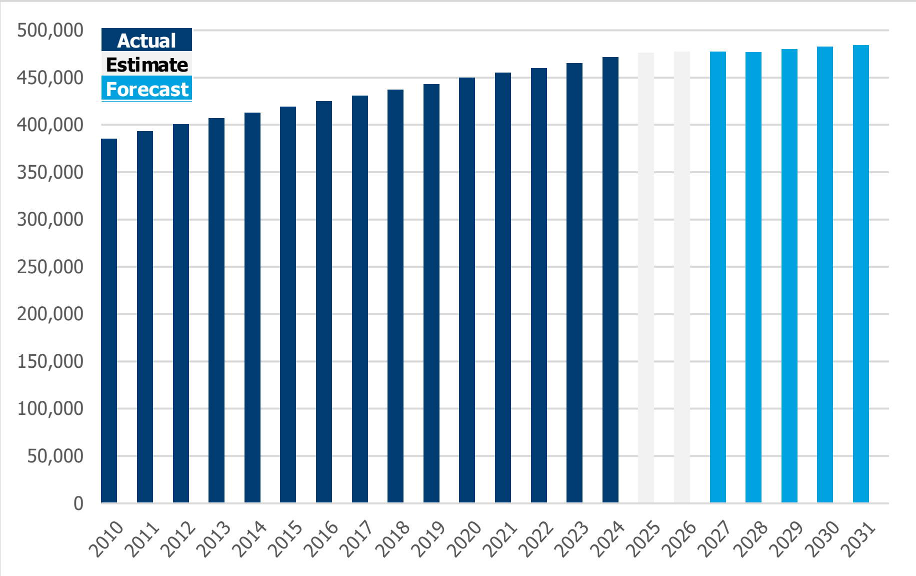


Figure 13.5: Residential Consumption per Connection

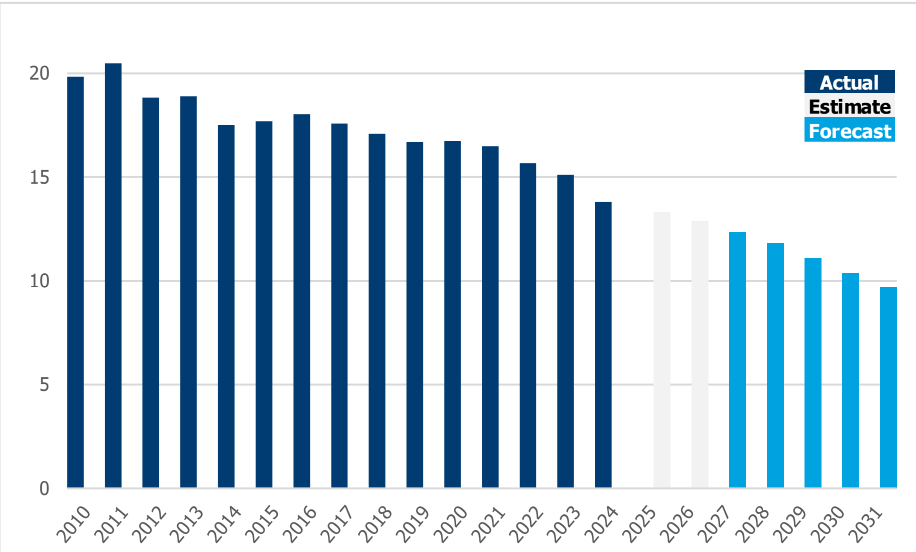


Figure 13.6: Residential Demand

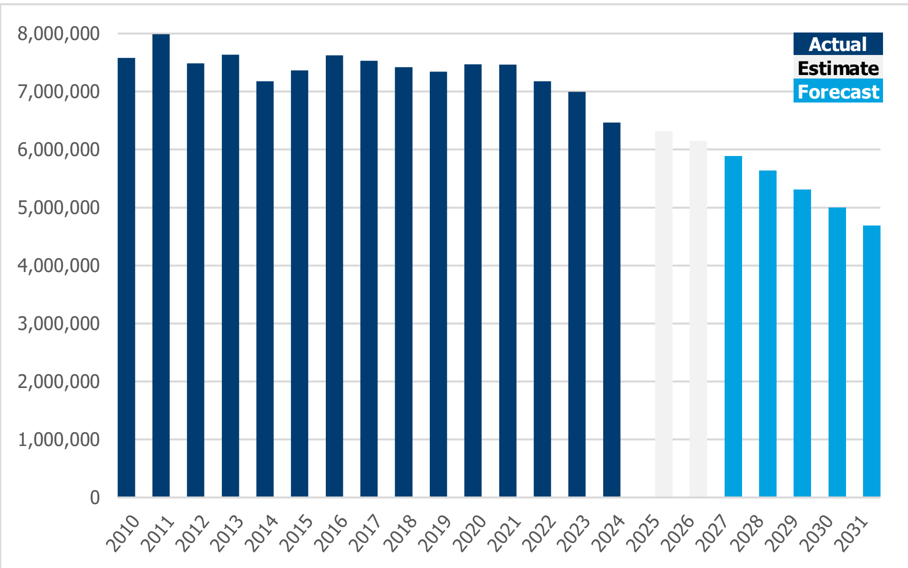


Figure 13.7: Commercial Connections Forecast (no.)

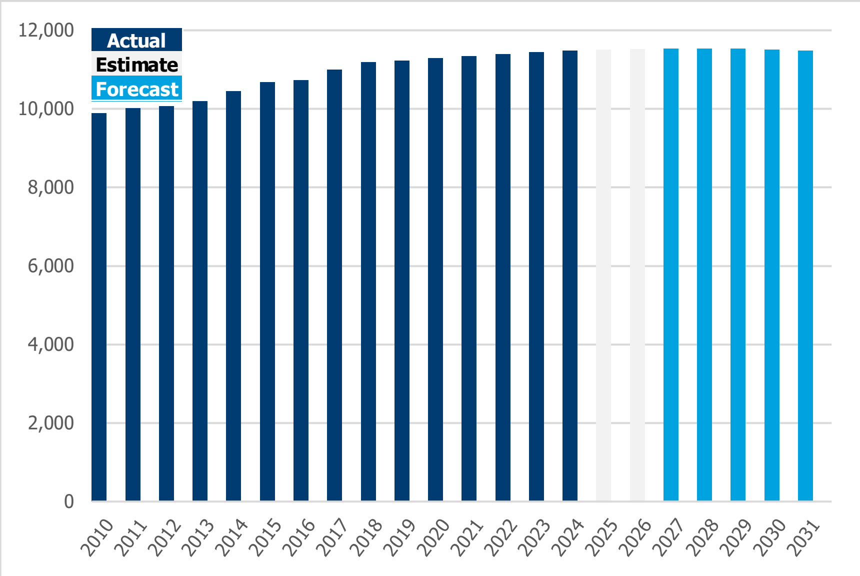


Figure 13.8: Commercial Consumption per Connection

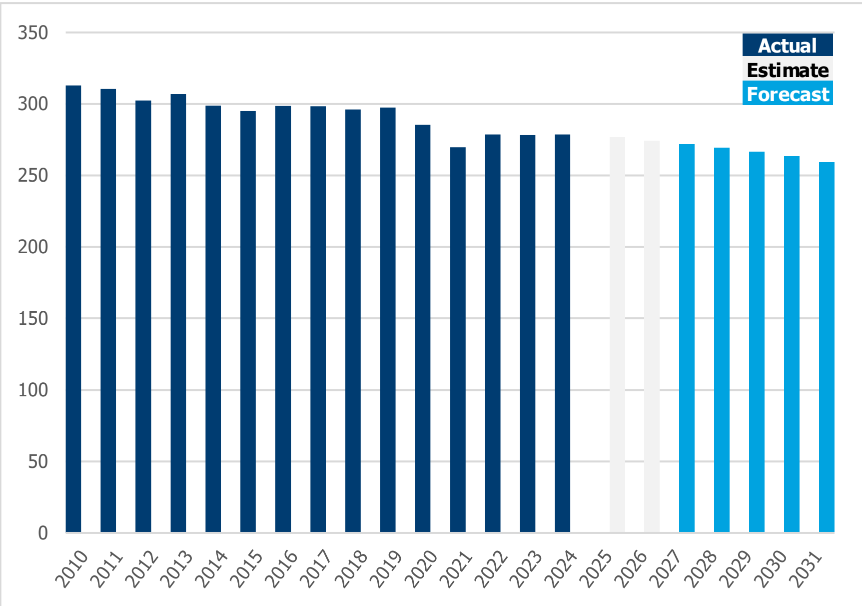


Figure 13.9: Commercial Demand (GJ)

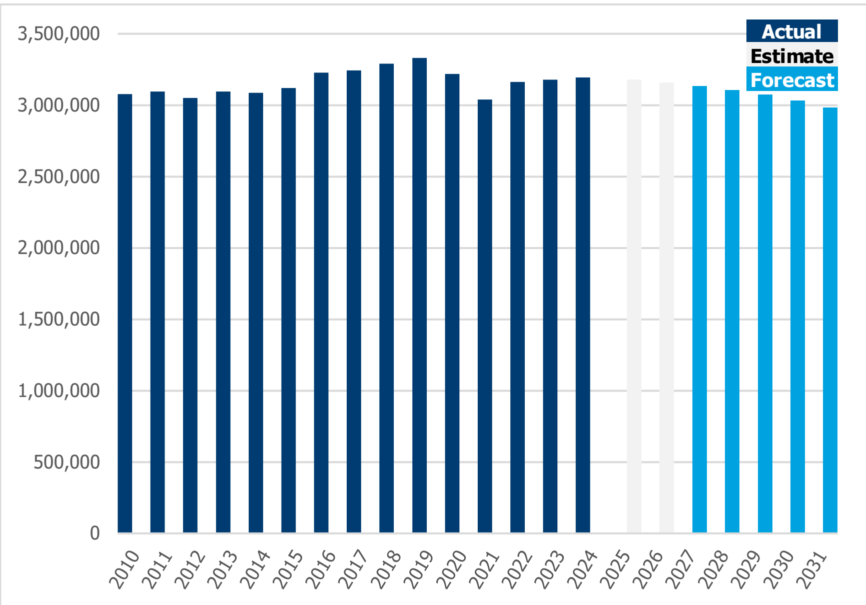


Figure 13.10: Industrial Connections Forecast

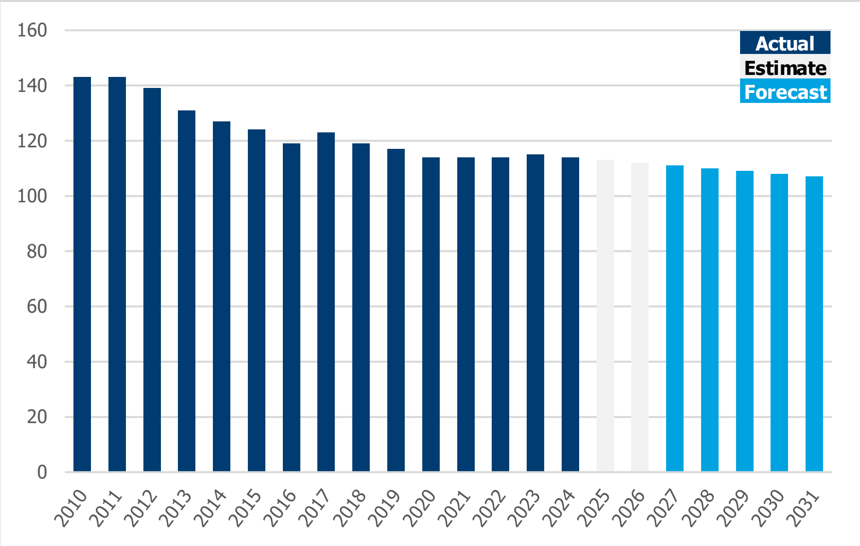
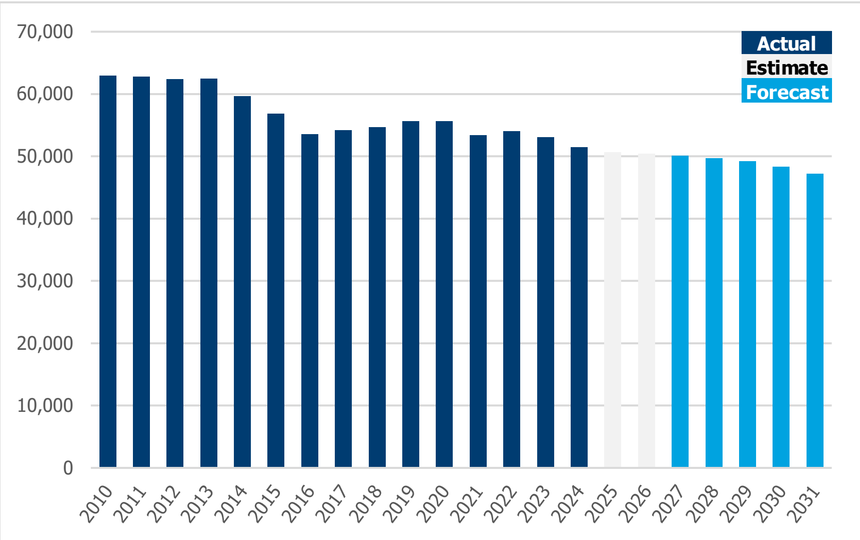


Figure 13.11: Industrial demand – MDQ (GJ)



14 Revenue and prices

This section sets out the total revenue, proposed prices and changes to the existing tariff variation mechanisms to apply over the next AA period.

IN THIS CHAPTER:

- **We have proposed to cut South Australian network prices by 3.6% on 1 July 2026 followed by increases of 0.9% each year thereafter in real terms. This equates to an upfront nominal price cut of 1.0%.**
- **Our proposed price path reflects the forecast growth of our capital base which will enable revenue growth commensurate with changes in our underlying costs.**
- **We are also proposing balanced adjustments to our tariff variation mechanisms (including related to the price cap mechanism) and our tariff structure, for greater consistency with the emission reduction objective in the NGO, but while also maintaining relative price stability for our customers.**

Our costs are referred to as 'building blocks' and are summed to determine total allowed revenue in each year of the next AA period. We recover our costs through the prices (or tariffs) that we charge retailers for providing reference services.

14.1 Regulatory Framework

We are required to determine total revenue for each year of the next AA period as the sum of our forecast opex, return on our capital base, depreciation of the capital base and a forecast of the cost of tax.

Our total revenue can also increase or decrease depending on our performance in relation to incentive mechanisms applying in the current AA period, such as the opex incentive mechanism (Efficiency Carryover Mechanism - ECM) and the capex incentive mechanism (Capital Expenditure Sharing Scheme – CESS).

Our prices are required to reflect, to the extent possible, the underlying cost of providing services to our customers.

14.2 Customer and stakeholder engagement

In developing this Final Plan, we have carefully considered the impact individual aspects of the plan will have on price.

Customers and stakeholders have told us consistently throughout our engagement phases that affordability is their highest priority. They have also indicated that price stability is important to them.

As part of our engagement in developing this Final Plan, we have also sought feedback on:

- our proposed price path,

- our proposed pricing structure, specifically in relation to the mix of fixed and variable components of our prices and how our pricing meets the NGO, including the new emission reduction objective, and
- tariff variation mechanisms, including a proposed hybrid (price/revenue cap) mechanism and other cost pass through events

Stakeholder feedback in respect to overall revenue and prices, and our responses to this feedback, are contained in Table 14.1.

Table 14.1: Summary of customer and stakeholder engagement on our revenue and prices

<table>
<tr><th>Topic</th><th>Customer and Stakeholder Feedback</th><th>Our Response</th></tr>
<tr><td rowspan="3">Revenue and Prices</td><td colspan="2">Stage 1 2 Engagement: Developing our Plans</td></tr>
<tr><td>• Stakeholders and customers have indicated a preference for price stability and predictability concerning our plans
• Customers told us that they equate affordability with steady and stable prices.
• At the RSP stage, customers and stakeholders indicated majority support for the declining block tariffs to avoid significant bill increases for higher usage customers and continuing with the price cap mechanism to avoid price volatility over an AA period.
• The AER did not accept our proposal to continue with our declining block tariff structure unchanged and asked us to consider other options for flattening tariffs. It also requested consideration of a hybrid mechanism for revenue control (combining the weighted average price cap with a revenue-based threshold).</td><td>• We have designed our price path such that we can deliver a nominal price cut of 1.0% in year 1 and real price increases of less than 1% in subsequent years, delivering on our commitment to stable pricing in the next AA period.
• Based on customer feedback and our own assessments of costs and benefits, we initially proposed in our RSP to continue with the current tariff structure and weighted average price cap approach to revenue control.
• In response to the AER's decision on our final RSP, we proposed an adjusted tariff structure in our Draft Plan, with a higher fixed charge and rebalancing of other price tiers to address emission reduction objectives, while still keeping customer bill impacts at reasonable levels.
• We also proposed the option of a hybrid mechanism at a revenue variation threshold of 10% for comment.
• Our Draft Plan encompassed two cost pass through proposals as practical steps to manage potential Safeguard Mechanism compliance costs and small-scale abolishment costs (when different from forecast).</td></tr>
<tr><td colspan="2">Stage 3 Engagement: Draft Plan Consultation
• Do you support our objectives of maintaining stable pricing and aligning revenue with underlying costs in setting our proposed price path? Would you prefer an alternative price path, and if so, on what basis?
• Do you support the options we are considering to adjust the tariff structure (and charge weightings), including an increase in the base charge for residential and commercial customers? If not, what approach would you prefer and why?
• Do you support the option we are considering for a new hybrid mechanism for revenue control with a 10% revenue variation threshold? If not, would you prefer an alternative approach and if so, why?
• Do you support the proposed cost pass through events for the Safeguard Mechanism compliance costs and any unrecovered abolishment costs? If not, would you prefer any alternative approaches, and if so, why?</td></tr>
</table>

	• In general, customers and stakeholders continued to support continuing declining block tariffs but were also supportive of our proposed changes to align with emission reduction objectives which ensure reasonable customer bill impacts only. • One stakeholder recommended replacing the current structure with a flat or inclining tariff structure but also recommended that this must be accompanied by appropriate protections and support mechanisms to counter the adverse bill impacts on households. • Regarding our proposed hybrid mechanism, one stakeholder indicated that it would prefer the retention of the price cap but otherwise, the 10% threshold approach was broadly supported. • Other cost pass throughs were supported as proposed.	• We responded to feedback that the fixed charge increase might impact low gas usage households and reduced the extent of the proposed increases for our residential and commercial tariffs accordingly, with more flattening of variable usage price tiers. • We do not accept comments that a more direct shift toward flat tariffs would be more affordable and equitable for customers; a view which is generally out of step with other stakeholder feedback we received. Our bill impact modelling demonstrates the adverse impact on larger households using gas, as one example of the negative bill impacts that would accompany flat tariffs. A compensation scheme would be inefficient and impractical to implement and would likely add considerable costs to the network. • We acknowledge stakeholders' preference for continuing the price cap mechanism but given the AER's preference for a hybrid mechanism, we have proposed a price cap with a 10% variation (revenue-based) threshold to apply in the next AA period.
	Stage 4 Engagement: Refining our Plans	
	• With further opportunity to discuss tariff structure options, stakeholders continued to acknowledge the negative customer bill impacts that accompany a direct shift to flat tariffs and how unacceptable they are in the current cost of living environment. • They also noted how such a shift would increase average gas prices for all customers, which is also not desirable during the energy transition amidst other potential price pressures. • There was one suggestion to place higher gas usage customers into different (higher priced) tariff categories, but this would have the same adverse impact on bills, including for larger households and small businesses.	• In response to feedback on our Draft Plan, we held a special reference group meeting on tariff structure to further discuss our engagement approach and the trade-off between emission reduction objectives being achieved (through flatter tariffs) and the negative bill impacts for higher usage customers that this would entail. We also presented an adjusted option for a change in tariff structure (compared with the Draft Plan). • In this option, we reduced the extent of the proposed fixed charge increase in response to feedback about the potential bill increase, albeit small, for low usage customers, and flattened other pricing tiers (in part) to balance revenue outcomes. • We also provided building block and price updates at our final reference group meeting as we refined our Final Plan.
	Final Plan Outcome	
	• Our Final Plan proposes a real price cut of 3.6%, or 1% cut after inflation. We have integrated our proposed tariff structure changes into our proposed prices for residential and non-residential customers in our PTRM model. Our proposed changes to the tariff variation mechanisms are reflected in our AA document (Annexure E) and further explained in Attachment 14.1.	

14.3 Revenue

This Final Plan outlines the basis of all the relevant building blocks that are used to determine building block total revenue. The building block total revenue with and without the cost of providing Ancillary Reference Services (ARS) is provided in Table 14.2.

Our building block revenue is recovered through the prices we charge retailers for providing domestic, commercial and demand haulage services and ARS. We are required to set our prices such that the total revenue we recover equals the building block total revenue.

The AER's Final Decision will provide for a series of price changes (or X-factors) to ensure this objective is achieved.

The building block total revenue, smoothed revenue and percentage changes in prices are set out in Table 14.3.

Table 14.2: Proposed Price Path, 2026/27 to 2030/31 ($nominal, million)

	2026/27	2027/28	2028/29	2029/30	2030/31
Building Block Total Revenue (excluding ARS)	235.4	234.4	269.3	278.6	299.1
Smoothed Revenue	257.7	260.6	261.9	263.1	264.1
Real Price Path	-3.56%	0.93%	0.93%	0.93%	0.93%
Nominal Price Path	-1.00%	3.61%	3.61%	3.61%	3.61%

Table 14.3: Building Block Total Revenue, 2026/27 to 2030/31 ($nominal, million)

	2026/27	2027/28	2028/29	2029/30	2030/31
Return on Capital	124.1	129.8	139.1	146.1	156.5
Return of Capital	18.0	12.5	21.2	25.8	31.9
Opex	87.8	97.5	113.0	111.1	110.4
Incentive Mechanism	8.5	-2.2	-0.8	-0.9	4.0
Cost of Tax	-	-	-	-	-
Building Block Total Revenue (including ARS)	**238.4**	**237.6**	**272.6**	**282.1**	**302.8**
Less ARS	2.9	3.2	3.3	3.5	3.7
Building Block Total Revenue (excluding ARS)	**235.4**	**234.4**	**269.3**	**278.6**	**299.1**

Note: Totals may not add due to rounding

14.4 Prices

As already noted, we recover our revenue through the prices that we charge retailers for providing reference services.

In the next AA period, we are proposing to cut South Australian network prices by 3.6% on 1 July 2026 followed by increases of 0.9% each year thereafter, in real terms. This equates to an upfront nominal price cut of 1.0%, which will reduce the average annual bill by:

- $6 for residential customers,
- $63 for commercial customers, and
- $2,800 for industrial customers.

Sections 14.5.5 and 14.5.6 set out our final proposed tariffs at the start of the next AA period, incorporating this price cut.

The following sections outline our current and proposed pricing structures for our customer segments, which determine charging for different levels of consumption. It also covers the weighted average price cap mechanism and our proposed new form of revenue control which combines elements of a price cap and revenue cap as a hybrid mechanism, into the next AA period. This impacts how prices might change within the AA period through the tariff variation mechanism for customers.

Both matters have already been consulted upon with our customers and stakeholders through our Reference Service Proposal (RSP). However, in response to the RSP and our stakeholder feedback received, the AER has asked us to review our proposals further, in consultation with our stakeholders. The AER indicated that it wanted further consideration of adopting a flatter tariff structure and a hybrid revenue control mechanism. It is seeking to disincentivise gas network growth and higher gas consumption, for better alignment with the emission reduction target aspect of the NGO. As indicated in Section 14.2, we consulted further on the tariff structure and the form of revenue control for the next AA period at our Draft Plan stage.

Following this process, we maintain that network tariffs should be structured to provide service providers with the greatest opportunity to recover their efficient costs, which is consistent with the National Gas Rules and the broader regulatory framework of the gas and electricity supply industry.

Gas retailers have ultimate control of the overall price and structure of their offering to our customers and generally do not reflect the gas distributors tariffs. Further, energy retailers are heavily promoting residential electrification which also significantly nullifies any perceived incentive created by declining block network tariffs.

In our view, efficient pricing remains at the core of the NGO, NGL and NGR, the primary objective of each is to deliver efficient prices in the long-term interest of consumers. However, we have presented an option for an adjusted pricing structure in the next AA period, as set out in the next section, that aims to also meet the emission reduction objective of the NGO, without compromising the other customer-related objectives. This approach is broadly supported by our stakeholders.

Section 14.6 discusses our proposed approach to revenue control, also broadly supported by stakeholders.

14.5 Pricing structure

14.5.1 Current pricing structure

Our current pricing structure includes two zones, South Australia (excluding Tanunda) and Tanunda.

The South Australia (excluding Tanunda) zone includes residential, commercial and industrial customers whilst the Tanunda zone includes only residential and commercial customers.

Prices for residential and commercial customers (Tariffs R and C respectively) consist of a number of volumetric (or consumption) based charging parameters (in dollars per GJ per day) and a fixed supply charge (in dollars per day).

We currently recover approximately 75% of our revenue in the residential and commercial segments in the variable (volumetric) components of our tariffs and 25% through the fixed components.

Our current variable pricing for residential and commercial customers involves higher prices for lower usage blocks and lower prices for higher usage blocks.

For example, the first residential pricing band broadly captures a customer using a gas cooker and solar boosted gas hot water system; the second step captures a customer with a non-solar boosted gas hot water system; while the final step captures customers utilising gas for space heating.

Prices for our larger industrial customers (Tariff D) are capacity based and consist of banded charging parameters (in dollars per GJ of MDQ) (see Table 14.7). The pricing structure provides economic signals to demand customers to ensure a smooth consumption profile rather than a 'peaky' one. The locational aspect of these tariffs also reflects the different cost of supplying customers and is designed to encourage demand customers to locate in those parts of the network that will impose the least costs on AGN (and hence customers).

We have not proposed any changes to the pricing structure for Tariff D customers because they have their own emission reduction obligations, and even small changes in tariffs can potentially impact the viability of their operations.

Benefits of the current pricing structure

Our current declining block tariffs represent a form of efficient non-linear pricing. That is, by charging a lower price for higher volume gas distribution, we ensure that demand is not zero, and so we can spread our fixed costs over more demand. Removing declining block tariffs would remove the ability to obtain these types of efficiency gains for our customers.

Further, as gas demand is greatly influenced by weather, the current structure ensures more stable revenue and prices despite volatility in weather from year to year.

Smoothing bills through the year

Our tariff bands are structured such that most of space heating demand occurs in the highest (lowest-priced) band for many of our customers. Therefore, our tariff structure also has the practical effect of smoothing bills through the year, making them higher in summer than they would be under a flat or inclining block tariff and lower in winter.

14.5.2 Customer and stakeholder feedback on our pricing structure

Our engagement regarding our tariff structure was summarised in Table 14.1 above.

It was at the RSP stage that we first consulted on our tariff structure. We found that most of our customers and stakeholders supported continuation of the declining block tariff, acknowledging its benefits and the unacceptable bill impacts for higher usage customers that would result from a shift to a flat structure.

One stakeholder who indicated support for flatter tariffs (and again at the Draft Plan stage) also stated that this should only be proposed if there are government subsidies or equivalent in place to offset the negative bill impact on customers. However, no such government policy or scheme currently exists to compensate those negatively affected. It would be impractical and inefficient for the network to introduce such a scheme for so many users and would increase the average price for all customers.

In response to our RSP, the AER requested that we consult further on options for flattening of the tariff structure, with consideration of bill impacts for customers.

The AER suggested that flattening over two AA periods might be appropriate if a move to flat tariffs in a single period is not.

We presented additional material in our Draft Plan on tariff options, including flattening over two AA periods (the "halfway to flat tariff" option) and an alternative option (including with a fixed charge increase) with less adverse bill impacts for higher usage customers. We engaged on these options further in Stage 3 of our engagement process.

Following our Draft Plan, we also held further customer workshops to discuss preferred options. At this stage, 72% of participating customers indicated support for declining block tariffs either as they are or with our recommended tariff changes.

In response to our Draft Plan, stakeholders continued to support declining block tariffs but there was some concern expressed that customers did not understand the issue of tariff structures and policy implications sufficiently enough. In response, we explained our earlier RSP engagement with customers which explored these topics in more detail. The KPMG summary report on the engagement with customers at the Draft Plan stage also demonstrates a high level of engagement on the tariff structure topic with AGN representatives.[5]

In general, stakeholder feedback on our Draft Plan, and in an additional stakeholder reference group meeting on tariffs, indicated broad support for our balanced approach to tariff structure change, without unreasonable customer bill impacts.

A few stakeholders expressed concern about the impact of a higher fixed charge on low usage customers and businesses, by way of marginally higher bills.

[5] KPMG, *Customer & Stakeholder Engagement Summary Report: Developing a customer-centric Draft Plan through genuine engagement*, 14 May 2025, pp 27-30.

In response to this feedback, we have refined our proposed changes to the tariff structure further and reduced the extent of the proposed increases to fixed charges for both the residential and commercial tariff categories.

14.5.3 Flat tariff impacts

Our assessment of the approach to flatten tariffs over two periods found that the impact on our customers would still be unacceptable and not in our customers' long-term interests.

Table 14.4 shows these impacts for residential customers (as option 1), including annual bill increases of

- $146-plus for around 63,000 residential customers who use at least 30 GJ per year.
- $459-plus for more than 10,000 customers who use at least 60 GJ per year.

Even if these increases occurred incrementally over the period, higher usage customers would still be paying the higher bills every year thereafter, and additional changes would only incrementally increase their bills even further.

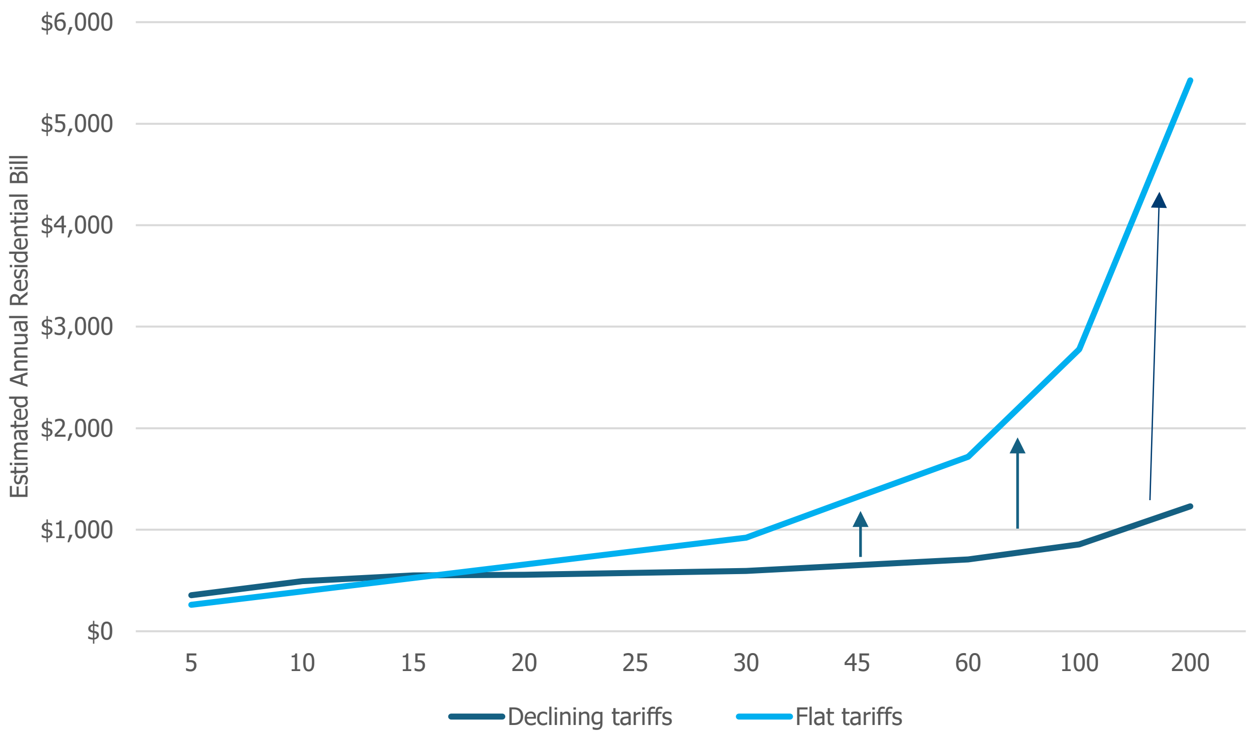
The impacts would still be unreasonable (in terms of significant negative bill impacts) even if a direct move to flat tariffs occurred over as many as four AA periods, or 20 years. This is because of the extent of change for bills that would be required from the current pricing structure, which is shown in Figure 14.1.

For this reason, we maintain our position in our RSP and Draft Plan that it is not reasonable to impose significant price increases on our existing customers, including high usage customers.

Such an increase would expect them to forgo an essential service or switch appliances (to avoid the higher charges). Many customers will not be able to afford the appliance switch, and disincentivising customers from using gas heating in their home if this is the only heating option available to them, in our view, is unacceptable.

Similarly, the cost to businesses which currently rely heavily on gas could threaten their viability.

Figure 14.1: Estimated annual bill based on 2025/26 tariffs by annual gas consumption (GJ) under declining and flat pricing structures ($ nominal)



Even the policy changes concerning gas appliances in Victoria have considered the timing of when customers will be affected by the changes rather than just imposing significant and sudden price rises on gas customers.

Further, a shift to flat tariffs for emission reduction benefits should not be at the expense of the price and efficiency objectives for consumers in the NGO.

Our RSP found that the potential emission reduction benefits are very small in comparison to these negative bill impacts (e.g., our modelled emission reduction benefits would be equivalent to just 0.02% to 0.04% of the average annual bill).Therefore, we have not adopted the AER's suggested change to our tariff structure (to flatten it over two AA periods) but have instead proposed more balanced structural changes, still consistent with an objective for greater emission reduction, but which have less severe customer impacts.

14.5.4 Our proposed changes to our pricing structure

As stated, we recommend more balanced options towards 'flattening' our tariffs which do not present significant bill increases to a portion of our customer base. The option we are proposing includes a small increase to our fixed charge for our residential and commercial customers.

This change would reduce the extent of gas consumption exposed to variable usage rates, which would be consistent with emission reduction objectives.

The increase is accompanied by the rebalancing of the other variable usage tiers, effectively flattening the higher usage price tiers. The modelled bill impacts from these changes for our residential and commercial customers are in Tables 14.4 and 14.5 respectively, indicated as option 2 in both cases. (The final proposed prices for the next AA period are in Tables 14.6 and 14.7.)

Changing the tariff structure in these ways minimises negative bill impacts on our customers and ensures that they continue to have the stable and affordable prices they need and value.

Table 14.4: Modelled residential bill impacts from changes in tariff structure, 2026/27 to 2030/31 ($ nominal)

Annual GJ	Annual bill under current tariffs 2025/26	Annual bill under halfway to flat tariffs' (1)	Difference from current tariffs (1)	Annual bill with 'increase in fixed charge and rebalancing across variable usage blocks' (2)	Difference from current tariffs (2)
5	$355	$318	-$37	$347	-$8
10	$493	$447	-$46	$492	-$2
15	$551	$543	-$16	$581	+$30
20	$556	$600	+$43	$577	+$21
25	$575	$670	+$95	$597	+$22
30	$594	$741	+$147	$617	+$24
45	$650	$953	+$303	$677	+$27
60	$706	$1,165	+$459	$737	+$31
100	$856	$1,730	+$874	$897	+$41
200	$1,231	$3,143	+$1,913	$1,297	+$67

Table 14.5: Modelled commercial bill impacts from changes in tariff structure, 2026/27 to 2030/31 ($ nominal)

Annual GJ	Annual bill under current tariffs	Annual bill under 'halfway to flat tariffs' (1)	Difference from current tariffs (1)	Annual bill with 'increase in fixed charge and rebalancing across variable usage blocks' (2)	Difference from current tariffs (2)
15	$602	$527	-$75	$604	+$2
45	$1,265	$867	-$399	$1,245	-$21
100	$2,482	$1,982	-$500	$2,419	-$63
200	$3,148	$2,922	-$226	$3,157	+$9
300	$4,587	$4,247	-$340	$4,594	+$7
1,000	$9,825	$11,111	+$1,285	$10,284	+$459
3,000	$18,208	$27,428	+$9,220	$19,091	+$883
5,000	$23,968	$43,513	+$19,545	$24,684	+$716
8,000	$27,663	$58,129	+$30,467	$25,941	-$1,722

14.5.5 Our proposed haulage tariffs

With the changes to the tariff structure for tariff categories C and D, we propose the tariffs as in Table 14.6, to take affect from 1 July 2026.

We also propose tariffs for tariff D customers by location as in Table 14.7, which continues the existing tariff structure in the current AA period.

As discussed in Attachment 14.1, the tariff structures adopted are efficient, contain no cross subsidy and have considered factors such as transaction costs, the LRMC and the ability for consumers to respond to price changes.

All proposed tariffs fall between the stand alone and avoidable costs.

Overall, our proposed tariffs cut our network prices in South Australia by 3.6% (before inflation) on 1 July 2027 and increase prices thereafter in line with the growth in our capital base.

This price path materially improves our ability to maintain stable credit metrics close to the levels assumed by the AER in setting our cost of debt allowance.

14.5.6 Our proposed Ancillary Reference Service prices

Lastly, Table 14.8 provides the ARS tariffs. These prices reflect the operating expense of providing these services and so deliver the appropriate price signals to customer

The exception is the small-scale abolishment service for which partial cost recovery is proposed, for consistency with the AER’s preferred pricing approach for this service (as was discussed in Chapter 7). This decision is partly on safety grounds so that customers are not disincentivised from organising the service when needed.

Table 14.6: Tariff R and C Domestic Haulage Service Tariffs

Charges per Network Day (excluding GST)	
Tariff R (excluding Tanunda)	
Base Charge ($ per day)	$0.3821
Charge for the first 0.0274 gigajoules of gas delivered ($ per gigajoule)	$40.7265
Charge for the next 0.0219 gigajoules of gas delivered ($ per gigajoule)	$17.7194
Charge for additional gas delivered ($ per gigajoule)	$3.9589
Tariff C (excluding Tanunda)	
Base Charge ($ per day)	$0.7686
Charge for the first 0.9863 gigajoules of gas delivered ($ per gigajoule)	$21.1456
Charge for the next 4.2740 gigajoules of gas delivered ($ per gigajoule)	$7.4673
Charge for the next 11.1780 gigajoules of gas delivered ($ per gigajoule)	$2.5426
Charge for additional gas delivered ($ per gigajoule)	$2.5426
Tariff R (Tanunda)	
Base Charge ($ per day)	$0.3821
Charge for the first 0.0274 gigajoules of gas delivered ($ per gigajoule)	$52.9445
Charge for the next 0.0219 gigajoules of gas delivered ($ per gigajoule)	$23.0352
Charge for additional gas delivered ($ per gigajoule)	$5.1466
Tariff C (Tanunda)	
Base Charge ($ per day)	$0.7686
Charge for the first 0.9863 gigajoules of gas delivered ($ per gigajoule)	$27.4893
Charge for the next 4.2740 gigajoules of gas delivered ($ per gigajoule)	$9.7075
Charge for the next 11.1780 gigajoules of gas delivered ($ per gigajoule)	$3.3054

Notes:

- The total daily Charge will comprise the Base Charge plus a Charge for the Quantity of Gas delivered (or estimated to have been delivered) through the Domestic Delivery Point.
- The Charge for the Quantity of Gas delivered (or estimated to have been delivered) through the Domestic Delivery Point will be calculated at the rates shown in the table.
- A reference in the table to the Gas delivered through the Domestic Delivery Point is a reference to Gas delivered through the Domestic Delivery Point whether for the account of the Network User or for the account of any other person or persons.
- Charges will be calculated to the nearest four decimal places.

Table 14.7: Tariff D Demand Haulage Service Tariffs $2025/26

Adelaide Region	Northern Zone	Central Zone	Southern Zone
50 gigajoules or less	$3,459.7254	$3,459.7254	$3,459.7254
Next 50 gigajoules ($ per gigajoule)	$67.2718	$79.8903	$94.2149
Next 900 gigajoules ($ per gigajoule)	$41.9976	$50.8065	$59.0038
Additional gigajoules ($ per gigajoule)	$12.7250	$16.0586	$17.7937

Other Regions	Port Pirie	Riverland	South East	Whyalla
50 gigajoules or less	$3,459.7254	$4,883.4849	$3,459.7254	$3,459.7254
Next 50 gigajoules ($ per gigajoule)	$67.2710	$98.2252	$67.2710	$67.2710
Next 900 gigajoules ($ per gigajoule)	$23.3137	$61.2070	$34.7215	$34.7215
Additional gigajoules ($ per gigajoule)	$11.6688	$12.7249	$12.7249	$12.6692

Notes:

- The Demand Haulage Charges shown above are charges for a complete calendar month.
- The Charge for a calendar month will accrue from day to day in equal portions.

Table 14.8: Ancillary Reference Services Tariffs $2025/26

Tariff Class	
Special Meter Read	$13.30
Disconnection	$91.00
Reconnection	$91.00
Meter Removal	$91.00
Meter Reinstallation	$99.00
Meter Gas and Installation Test	$271.00
Abolishment Service	$250.00

14.6 Form of revenue control

14.6.1 Current price cap

The current price cap control places a constraint on the overall average movement in tariffs from one year to the next (referred to as a weighted average price cap (WACP)). The constraint allows average prices to change by the annual change in the Consumer Price Index (CPI) less the X-factor[6]. Under a price cap, the business is exposed to volume risk – that is, any variation in volume and subsequent revenue impact is borne by the business. This significantly reduces price volatility for customers within an AA period.

In addition, the economic rationale for the price-cap form of control is to provide a financial incentive for regulated businesses to rebalance prices among their service offerings towards a form that is more allocatively efficient.[7]

14.6.2 Customer and stakeholder feedback on our price cap

We engaged with our customers on the matter of our price cap and alternatives such as a revenue cap, as was set out in Table 14.1 earlier in the chapter.

Under the revenue-cap form of control, tariffs are set such that only the building block revenue determined by the AER is recovered over the AA period. Therefore, any annual difference in revenue between the actual and the approved allowance will be passed through to customers - via lower tariffs if actual revenue is higher than the allowance, and higher tariffs if actual revenue is lower than the allowance. For this reason, the tariffs can change in real terms from year to year under this approach, depending on demand outcomes.

Therefore, a shift from a price cap to a revenue cap would shift volume risk to our customers and could lead to considerable price volatility during the regulatory period, particularly given the variance in weather from year to year and the subsequent volatility in volume of gas delivered through the network.

During our RSP engagement process, our customers and stakeholders indicated to us that they prefer price stability and predictability and that shifting more volatility onto customers within a regulatory period is not desirable.

Our engagement on our Draft Plan continued to demonstrate a preference among our customer base and stakeholders for stable prices. One stakeholder indicated in its submission that it would prefer continuation of the price cap approach, but that a hybrid mechanism with a 10% variation threshold was its next preferred option.

14.6.3 AER request for further consideration of a hybrid mechanism

In response to our RSP, the AER has requested that we consider a hybrid mechanism which combined elements of the weighted average price cap approach and revenue cap.

The AER cited the approach recently proposed by Jemena (for its 2025-30 NSW gas distribution network AA) as an "acceptable approach." The Jemena proposal was for a 'cap and collar' approach whereby a price cap applies up to a threshold of 5% for annual revenue variation (from forecast) and beyond this level, there is a 50:50 sharing of the incremental revenue gains or losses between customers and the business.

14.6.4 Our proposed price cap mechanism

Our engagement on the appropriate mechanism reinforces our position that the most suitable approach for our customers is the price cap form of regulation. The challenges presented by the energy transition only strengthens the case for this type of approach, ensuring more price stability when there might be sudden demand shifts.

We considered the application of the Jemena proposal for a hybrid mechanism to our South Australian network. However, we consider that this approach is not the most suitable (with a 5% threshold) as it can place too much burden on our customers during times of lower demand such that higher prices would be passed through to them too quickly.

Instead, as a second-best option, we propose a hybrid price cap mechanism with a revenue variation threshold of 10%. This approach balances the AER

[6] In the case of AGN South Australia, there is also an adjustment factor reflecting the movement in the annual price of unaccounted for gas.

[7] See proof in Laffont, J and J Tirole /(2001), *Competition in Telecommunications*, MIT Press, pp.66-67 (as advised by Incenta Economic Consulting in our submission to the AER review, June 2023).

preference for a hybrid mechanism without the potential negative customer impacts of a "tight" hybrid price cap. Under our proposed approach, the incremental revenue gain or loss beyond the 10% threshold would be shared with the business on an equal (50:50) basis. The approach will minimise the volatility from year to year on our customers and allow the business to manage demand changes. It will also ensure that there is some incremental adjustment for any significant differences in demand from volume forecasts.

We consider this hybrid mechanism is consistent with our customer engagement outcomes on our RSP and Draft Plan, which demonstrated a high preference for a price cap which offers high predictability with minimal volatility from year to year in pricing.

14.7 Other proposed changes to the price variation mechanisms

In general, we are proposing a consistent approach to that applying in the current AA period in that we will make annual price adjustments for the annual change in inflation and the applicable X-factor each year. These adjustments ensure we recover our allowed building block revenues.

We will be allowed to vary our prices over the next AA period in accordance with procedures approved in our AA Document (referred to as approved price or tariff variation mechanisms; see Section 4.4 of the AA Document).

In addition to the hybrid price mechanism discussed in the previous section, our Final Plan proposes further changes to the tariff variation mechanisms in the next AA period to enable 'true ups' which also applied in our Victorian distribution network AAs, to account for:

- the cost of meeting the Safeguard Mechanism obligations for the network (which are likely to be relatively low over the next AA period); and
- a true up of under or over recovered abolishment costs.

The true up of abolishment costs occurs to ensure that the prices the network pays for only includes the actual costs for this service. The mechanism addresses any uncertainty about the scale of abolishments that might occur, as well as in the service cost.

14.7.1 Other Cost-Pass Throughs

Other proposed cost adjustment factors, which form part of the price control formula, reflect those in the current AA period for:

- Variations in the UAFG contracted price from the forecast, and
- Cost Pass Through Events.

The definition and treatment of any 'Cost Pass Through Events' are outlined in Attachment 14.1. These are consistent with those currently applying, which are:

- Regulatory Change Events,
- Service Standard Events,
- Tax Change Events,
- Terrorism Events,
- Insurer Credit Risk Events,
- Insurance Cap Events, and
- Natural Disaster Events.

These adjustment factors allow for any material pass through amount approved by the AER to be recovered from or returned to our customers.

Both the UAFG true up and potential cost pass through factors (including the requirements applied to these) are presented in more detail in Section 4.5 and Annexure E of the AA Document.

14.7.2 Rebalancing Control Mechanism

The rebalancing control provides greater flexibility to adjust prices from one year to the next than allowed for by the price control on its own. The rebalancing control allows average prices for each of the 14 pricing categories set out in Tables 14.6 and 14.7 to change by a fixed percentage above that allowed for by the price control.

We propose to maintain the current rebalancing control of 2% (before inflation).

The rebalancing control formula forms part of Annexure E of the AA Document and is explained in more detail in Attachment 14.1.

14.7.3 Tariff Variation Procedures

We will continue to notify the AER in respect of any variations to our prices at least 50 business days before those prices are proposed to come into effect. Our notification will continue to provide an explanation of how the proposed variations comply with the price control and rebalancing control. We will also continue to publish our prices, including our pricing proposals, on our website.

14.8 Summary

In this chapter, we have explained how we recover our costs, or building block revenue, through the prices that we charge for providing network services.

Our Final Plan proposes to cut our network prices over the next AA period by 3.6% (1.0% nominal) on 1 July 2026 followed by increases of 0.9% each year thereafter.

Our proposed price path will enable revenue growth commensurate with changes in our underlying costs.

We have also outlined the changes to our tariff structure and tariff control mechanisms that we have proposed for the next AA period. More detail on these approaches is set out in Attachment 14.1.

15 Network access

Our current terms and conditions are a key part of our relationship with network users, and we will continue to consult on any refinement required for the next AA period

IN THIS CHAPTER:

- **We do not propose any material changes to our standard terms and conditions, following our consultation with network users.**

Our reference service terms and conditions set the contractual arrangements by which Network Users gain access to our distribution network

A key part of our relationship with Network Users[8] is a contractual agreement between the parties that governs the conditions (or terms) of access to our networks, commonly referred to as a 'Haulage Agreement'. The terms and conditions of the Haulage Agreement typically reflect the AER-approved terms that are set out in our AA Document, unless otherwise agreed by the parties.

In prior AA periods, we have undertaken extensive engagement on updates to our terms and conditions, including harmonising them nationally across our distribution networks, resulting in the lowest sustainable cost and ease of use for our users.

For the upcoming AA period (2026/27 to 2030/31), we are not proposing any material changes to our terms and conditions.

15.1 Regulatory Framework

We are required under the NGR[9] to specify the terms and conditions on which each reference service will be provided in our Final Plan to the AER by 1 July 2025.

The General Terms and Conditions (GT&Cs) are set out in our AA Document.

15.2 Customer and stakeholder engagement

Our current GT&Cs incorporate considerable consultation with stakeholders over a long period of time. They:

- are harmonised with the Victorian, Albury NSW and Queensland GT&Cs which provides national consistency for Network Users on AGN networks and the Victorian MGN network.
- incorporate standard amendments previously agreed with Network Users through negotiations, and
- incorporate other customer information clauses from other gas businesses' GT&Cs.

We have continued to apply previous AER decisions as a base for setting the proposed terms to apply to our network over the next AA period.

At our combined SARG and RRG meeting in February 2025, we presented our proposed approach and next steps to engaging on the GT&Cs.

We stated how we currently do not propose any material changes

[8] Network Users are primarily gas retailers or self-contracting users of our networks.
[9] NGR 48(d)(ii))

but that we will continue to consult through the Draft Plan process, including related to:

- The Unfair Contract Terms legislation, which was introduced on 9 November 2023. AGN is considering the impact of this legislation on its GT&Cs.

15.3 AA Document

As noted earlier, the AA Document sets out the proposed prices and terms and conditions under which we offer access to our networks. The format of the proposed AA Document remains largely unchanged from the current AA Document.

15.4 Summary

The terms and conditions are a key part of our relationship with network users. Our proposed terms have gone through significant consultation with stakeholders over a considerable period of time. We will continue to consult with Retailers, Self-Contracting Users and other stakeholders on any refinement required for the next AA period.

Glossary			
AA	Access Arrangement	HRS	Haulage Reference Services
ACQ	Annual Contract Quantity	HSE	Health Safety Environment
AEMO	Australian Energy Market Operator	HyP Adelaide	Hydrogen Park Adelaide
AER	Australian Energy Regulator	HyP SA	Hydrogen Park South Australia
AGIG	Australian Gas Infrastructure Group	I&C	Industrial and Commercial (customers)
AGN	Australian Gas Networks	ILI	Inline Inspection
AMP	Asset Management Plan	LTIFR	Lost Time Injury Frequency Rate
AMS	Asset Management Strategy	MDQ	Maximum Daily Quantity
API	Asset Performance Index	MGN	Multinet Gas Networks
ARENA	Australian Renewable Energy Agency	MUS	Multi-User Services
ARS	Ancillary Reference Service	Next AA period	2026/27 to 2030/31
CALD	Culturally and Linguistically Diverse	NGL	National Gas Law
capex	Capital Expenditure	NGR	National Gas Rules
CESS	Capital Expenditure Sharing Scheme	opex	Operating Expenditure
CPI	Consumer Price Index	OTR	Office of the Technical Regulator
CRM	Customer Relationship Management	PJ	Petajoule/s
Current AA period	2021/22 to 2025/26	PMC	Periodic Meter Change
DBP	Dampier Bunbury Pipeline	PSP	Priority Services Program
DBYD	Dial Before You Dig	RAP	Reconciliation Action Plan
DEI	Diversity, Equity and Inclusion	RGGO	Renewable Gas Guarantee of Origin
DMSIP	Distribution Mains and Services Integrity Plan	RoRI	Rate of Return Instrument
DP	Delivery Point	RRG	Retailer Reference Group
DRP	Debt Risk Premium	RSP	Reference Service Proposal
DRS	District Regulating Station	RTU	Remote Terminal Units
EBSS	Efficiency Benefit Sharing Scheme	SARG	South Australian Reference Group
ECM	Efficiency Carryover Mechanism	SCADA	Supervisory Control and Data Acquisition
EDD	Effective Degree Day	SOCI	Security of Critical Infrastructure
ERA	Economic Regulation Authority	TAB	Tax Asset Base
ESCOSA	Essential Services Commission of South Australia	TJ	Terajoule/s
GIS	Geographic Information System	TRIFR	Total Recordable Injury Frequency Rate (the number of total recordable injuries per million hours worked)
GJ	Gigajoule/s	UAFG	Unaccounted for Gas
HDPE	High-Density Polyethylene	WAPC	Weighted Average Price Cap
HIA	Housing Industry Association	WPI	Wage Price Index

Contact us

For **general queries**, please contact:

Lucy Huxter

Stakeholder Engagement Manager

D+61 437 132 103

E regulatoryengagement@agig.com.au
lucy.huxter@agig.com.au

For **regulatory queries**, please contact:

Peter Bucki

Head of Regulation

D+61 8 8418 1112

E Peter.bucki@agig.com.au

For **commercial queries,** please contact:

Grant Macauley

Commercial Manager

D+61 8 8 8418 1158

E Grant.macauley@agig.com.au

Our SA Office

Australia Gas Infrastructure Group

Level 6, 400 King William Street

Adelaide, SA 5000