Attachment 1.2

Draft Plan: Five year plan for our Victoria and Albury networks

Final Plan 2023/24 – 2027/28

July 2022

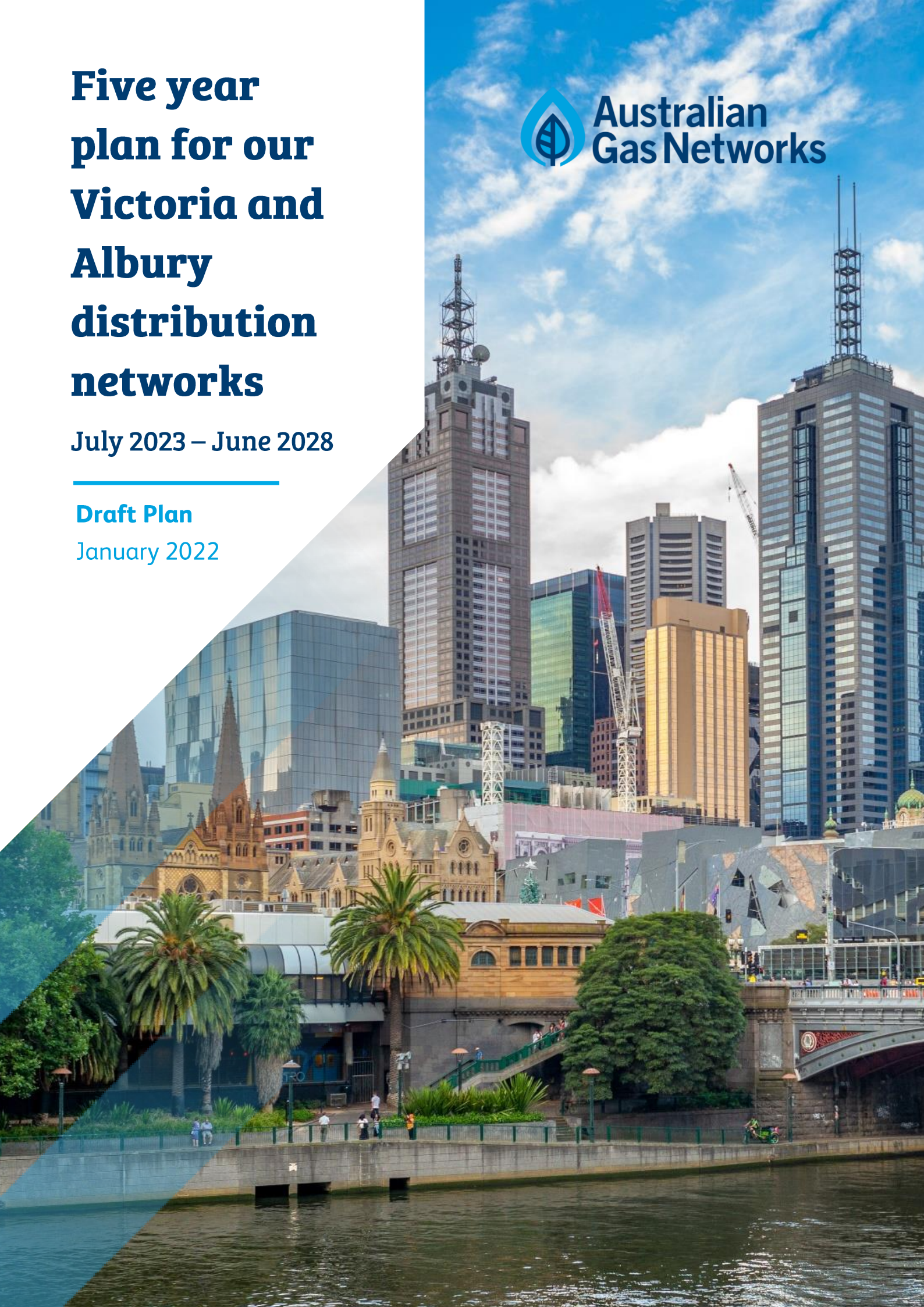
Five year plan for our Victoria and Albury distribution networks

July 2023 – June 2028

Draft Plan

January 2022

Australian Gas Networks



Contents

We are Australian Gas Networks. We deliver gas safely and reliably to more than 700,000 homes and businesses in Victoria and Albury every year.

Our vision is to be the leading gas infrastructure business in Australia by delivering for customers, being a good employer and being sustainably cost efficient.

We are committed to sustainable gas delivery today, and tomorrow. Gas networks can decarbonise heat through the use of renewable gases like hydrogen and biomethane. Through Hydrogen Park Murray Valley and the Australian Hydrogen Centre we are laying a foundation for a strong zero emissions future so our customers can continue to enjoy gas cooking and heating in their homes and businesses.

CEO Foreword

I am pleased to present the Australian Gas Networks (AGN) Victoria and Albury Draft Plan for the 2023/24 to 2027/28 period.

This document sets out our plan for the next Access Arrangement (AA) period. It sets out how we will deliver safe, affordable and reliable services to our customers during a period of significant and rapid change in the energy sector.

AGN is part of Australian Gas Infrastructure Group (AGIG), one of Australia's largest gas infrastructure businesses. Through AGN Victoria and Albury we serve over 700,000 customers in Victoria and New South Wales, including in the Melbourne CBD, northern, eastern and outer southern areas of metropolitan Melbourne, the Mornington Peninsula, and northern, eastern and south- eastern areas of Victoria and Albury. AGN plays a vital role in delivering safe, reliable, affordable and low emissions energy for residential, commercial and industrial customers.

In serving these customers it is our vision to be the leading gas infrastructure business in Australia. We aim to do this by achieving top quartile performance in delivering for customers, being a good employer and being sustainably cost efficient.

In the current Access Arrangement (AA) period we have performed well against our vision. Our customer satisfaction scores have improved throughout the period, reaching the highest score to date of 8.7 for AGN in 2021. We have repaired 99% of leaks within one hour and continued to improve our performance against health and safety metrics.

We have also delivered almost 300 kilometres of mains replacement, including completing mains replacement in the Melbourne CBD. Significant progress in mains replacement achieves emissions reductions in the near-term and ensures our network is ready for hydrogen in the future. Finally, we have delivered operating costs within our benchmarks.

The current AA period has coincided with several significant challenges. The ongoing pandemic and public health measures have had a significant impact on our customers, staff and stakeholders, as have bushfires and storms throughout the period.

We have responded to these challenges by delivering against our benchmarks and with targeted measures. We supported the Energy Networks Australia network relief package which deferred network charges for customers facing hardship as a result of the pandemic.

In addition to targeted measures, by maintaining and improving our performance against our benchmarks we have continued to

provide our customers with a safe and reliable source of energy during a period of uncertainty.

We aim to maintain and further strengthen our performance in the next AA period as outlined in this Draft Plan. We aim to improve customer satisfaction, while maintaining our safety and reliability. Customers will also continue to connect to the gas network. Our demand forecasts for the next AA period reflect customers taking advantage of the favourable competitive position of natural gas compared to electricity, including the inherent reliability of the gas network with an average unplanned outage of around once every 30 years.

For AGN, continued network growth in the next AA period will see mains installed for 69,000 new connections. These new connections help to lower costs for existing customers and provide new customers with the infrastructure ready to deliver renewable gases.

In the next AA period it will also be critical to establish a framework for the decarbonisation of our network.

We strongly support the decarbonisation of Victoria's economy and the targets established by the State Government.

Our board has recently endorsed a low carbon strategy that includes targets to deliver 100% renewable gas solutions from 2025, deliver a 10% renewable gas blend across our distribution networks by 2030, and a stretch target to achieve the full decarbonisation of our distribution networks by 2040, or 2050 at the latest.

These targets align with government policy and our expectations for future technological developments in renewable hydrogen and distributed energy technologies. We believe our network has a pivotal role in the energy sector of the future, delivering renewable gases like hydrogen to customers.

Our Draft Plan recognises that the role of gas networks as the economy moves towards net zero emissions is uncertain. We know that gas networks will continue to play a role for the foreseeable future, but the nature of that role can vary significantly depending on technological developments and government policy.

Our Draft Plan puts in place the measures needed to ensure we can continue to deliver safe, reliable and affordable energy through the transition, for plausible scenarios that might eventuate.

The Draft Plan includes $25 million in no regrets actions to ensure the network is ready for the distribution of renewable hydrogen. Some of these measures also have the added benefit of improving safety and reliability.

In addition to balanced expenditure to help make our network hydrogen ready, the Draft Plan proposes accelerating $144 million of depreciation. Depreciation is the right tool to address the uncertainty we face. It provides a means to maintain the competitiveness of our network in the near term in delivering natural gas and in the long term as part of a net zero emissions energy system. In adjusting depreciation we have been careful to avoid exposing customers to significant additional costs. The approach adopted is measured – balancing the risks and opportunities of an uncertain future, while delivering improved value for customers.

Overall, our Draft Plan delivers an upfront price cut of 8% (after inflation) on 1 July 2023, which builds on price cuts delivered by our business in the current period. Our proposal will ensure the network can deliver safe, reliable and affordable energy to customers now and into the future as the energy sector transitions to net zero emissions.

Our Draft Plan overall has been developed following a significant program of customer and stakeholder engagement. Our engagement has reached 153 customers and stakeholders, included 14 workshops. Again, it is worth noting this engagement has occurred during a challenging period and we thank our customers and stakeholders for their participation and perseverance.

This Draft Plan represents a further and important opportunity for customers and stakeholders to contribute as we work towards our Final Plan for submission to the Australian Energy Regulator in July 2022. Our approach to engagement provides several opportunities for customers and stakeholders to express their views and contribute to our plans and is a key part of our no surprises approach. I encourage our customers to put their views forward so that we can prepare a Final Plan that is capable of being accepted by our customers and stakeholders.

Craig de Laine

Chief Executive Officer

Australian Gas Networks

Lower prices

↓8%

(after inflation)

We have engaged with customers in Victoria and Albury to develop our Draft Plan for the five year period 2023/24 to 2027/28

In line with what our customers told us was important to them, this plan has 3 key themes:

- **Get the basics right**
- **Focus on the future**
- **Provide affordable and accessible services**

Lower funding costs

Rate of return of 4.21 % down from 5.75 % in the last period

Efficient incentives

- Opex & Capex Efficiency Schemes
- Gas Network Innovation Scheme

Safety focus

Maintain strong leak performance and continue to monitor performance and condition of mains

Future focus

Investing in 'no regrets actions' and renewable gas communications to prepare the network for a decarbonised future

Customer focus

- New digital customer services
- Priority Services Program

Keeping options open

Supports the long term competitiveness of the network to provide energy choice for customers in a net zero carbon future

Purpose of this plan

Regulatory framework

The National Gas Law (NGL) and the National Gas Rules (NGR) provide the framework for the regulation of certain gas pipelines in Australia.

This framework is enacted in Victoria through the *National Gas (Victoria) Act 2008*.

In Victoria, the AER is responsible for regulation under the NGL and NGR framework, including the approval of the AA proposals and revisions every five years.

The AA contains our proposed reference services and terms and conditions under which a customer can gain access to the AGN Victorian and Albury distribution networks.

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.

The terms and conditions approved through an AA set a framework around which gas distribution network operators like AGN and shippers (energy retailers and large businesses) can negotiate access. These terms and conditions then form the basis of the network component of residential and small business customers' bills.

Our review objectives

Our aim is to develop a plan that:

- ✓ Delivers for current and future customers.
- ✓ Is underpinned by effective stakeholder engagement.
- ✓ Is capable of being accepted by our customers and stakeholders.

Important to meeting these objectives is a "no surprises" approach to engagement, which means customers and stakeholders have been involved in the development of the Final Plan. A key element of the no surprises approach is the publication of this Draft Plan. The Draft Plan seeks feedback on our plans for the Victorian and Albury distribution networks for the next AA period commencing 1 July 2023. It will inform our Final Plan, which we are required to submit to the AER by 1 July 2022.

The Draft Plan provides our preliminary views on the activities and expenditure we propose to undertake in the next AA period. It includes feedback received to date from our customers and stakeholders through our engagement program.

After the opportunity to comment on the Draft Plan, our customers and stakeholders will also have further opportunity to engage as we develop our Final Plan. The AER will also engage with stakeholders through its own process.

How to read this plan

The first seven chapters of this document provide an overview of our plans, our business, our stakeholders, the future of gas, our pipeline services and the process we have undertaken to develop a plan that meets our objectives.

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

- *Operating expenditure* (opex) – the expenditure we require to run our business day-to-day (Chapter 8);
- *Capital expenditure* (capex) – the investment in our assets required to deliver services to our customers (Chapter 9);
- *Capital base* – the total value of our investment in the Victorian and Albury networks, which we have not yet recovered from customers and therefore need to finance (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).

All numbers used throughout this Draft Plan are in dollars 2022/23, unless otherwise labelled.

Next steps

We encourage our customers and stakeholders to provide further feedback on this Draft Plan. Your feedback is a key means of achieving our objective of submitting a Final Plan that delivers for our customers and is capable of being accepted.

We have highlighted key questions and issues on which we are seeking your feedback.

Your feedback can be provided by Monday 7 March 2022:

- online at gasmatters.agig.com.au
- by mail
- in person

Contact information is provided on the back cover of this document.

1 January to 30 June 2023 extension

Framework

In April 2019, the Victorian Minister for Energy, Environment and Climate Change advised of the intention to make changes to the timing of the Victorian electricity and gas network price resets to operate on a financial year basis. This would allow network and retail price changes to both take effect on 1 July and to bring Victoria into alignment with other National Electricity Market states. This was seen as a better outcome for Victorian energy customers.

On 27 October 2020 the *National Energy Legislation Amendment Act 2020* (Vic) (NELA Act) came into effect. On 30 September 2021 the Victorian Government published an Order in Council under the National Gas (Victoria) Act 2008 to give effect to the extension of the current AA period.

To facilitate the transition, the Order sets out that the six-month period from 1 January 2023 be treated as an extension of the current AA period, so that the next AA period commences 1 July 2023 (rather than 1 January 2023). When determining the revenue for the six month period 1 January to 30 June 2023, the Order requires:

- The use of the 2018 Rate of Return instrument instead of the 2015 Rate of Return Guideline applicable to the current AA period;
- Forecast operating expenditure which either reflects expected levels of opex for the six month period or is equivalent to half the final year's benchmark of the current AA period (being calendar year 2022);
- Forecast capital expenditure which either reflects expected levels of capex for the six month period or is equivalent to half of an average of current AA period benchmark;
- Forecast depreciation as per current AA period schedules;
- Incentive payments – the AER to determine how the incentive schemes are applied, if at all; and
- Prices for the six month period to not exceed the prices set by the AER for the regulatory year commencing 1 January 2022, adjusted for inflation.

Transitional arrangements

In line with the Order, the AER released a position paper on 8 November 2021 that sets out transitional arrangements for the six-months, which will:

- base the prices to apply in the 1 January to 30 June 2023 six-month period extension period on 2022 tariffs;
- make a revenue adjustment in the next AA period to true up for any under or over recovery in revenue that arises from continuing with 2022 prices in the six-month period;
- use an updated demand forecast from the business for the period 1 January 2023 and 30 June 2023 to calculate the revenue expected to be recovered; and
- apply a simple trended-forward methodology for capex and opex, similar to that applied for the Victorian electricity distribution businesses in 2021, to determine the applicable building block revenue recoverable for the period 1 January 2023 to 30 June 2023.

Variation proposal

We are required to submit to the AER a proposal for the six-month period 1 January to 30 June 2023 on 1 April 2022. This proposal will set out the key building blocks and proposed revenue adjustment in the next AA period consistent with arrangements detailed above.

1 Plan highlights

Our Draft Plan outlines the activities and investments we propose to undertake for the 2023/24 to 2027/28 period and the resulting price change for our customers.

IN THIS CHAPTER:

- **We have delivered against our targets in the current AA period by providing strong safety, reliability and customer service, connecting a record number of new customers and completing our low pressure mains replacement program.**
- **We are proposing an upfront price cut of 8% (after inflation) on 1 July 2023, building on the price cut of 5% delivered on 1 January 2018.**

Customers are at the centre of our planning, and their feedback helps us to deliver the services they value today and in the future. Alongside the other Victorian gas distribution businesses, we are engaging extensively with customers and stakeholders and their insights have informed our Draft Plan.

This section highlights how we have developed our Draft Plan, our achievements for the current period and the key elements of our proposal for the next period.

1.1 Developing this plan

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

To date we have undertaken a series of 14 dedicated customer workshops spanning six locations and 153 participants. Insights from these workshops have informed our Draft Plan.

In the development of this Draft Plan we have completed stages one and two of our engagement program (see Chapter 5). Further feedback and engagement activities will help to refine our Final Plan for submission to the AER in July 2022.

1.2 Our track record

In the current AA period we have achieved strong performance towards our vision, met the key safety standards set for the network and delivered the major outputs set by the AER.

Our vision is to continue to deliver quality services that our customers value, be recognised as a good employer and to remain sustainably cost efficient. During the current period we have delivered on that vision, and we aim to continue our progress during the next AA period.

Our key achievements during the current AA period so far are summarised below.

Delivering for customers

- Strong public safety and reliability performance – repairing 99% of leaks within one hour and keeping interruptions low; and
- Good customer service – an average customer satisfaction score of 8.2, 2021 year at 8.7, our highest score to date and 99% of new connections completed within 20 days.

A good employer

- Continuous improvement in health and safety – we have updated our approach to

measuring health and safety and achieved an average Total Recordable Injury Frequency Rate (TRIFR)

- 9.9 since we began tracking this metric in 2018; and
- Employee engagement and skills development – annual average engagement score of 69%, achieving top decile in 2020, and
- compliance training above 90%.

Sustainably cost efficient

- Price cut of 5% (after inflation) on 1 July 2018;
- On track to complete low pressure mains replacement program totalling 297 kilometres and including the Melbourne CBD – this delivers on our target for the current AA period, represents a significant safety milestone for our network and our customers, and will reduce reported scope 1 emissions by a further 13,500 tonnes CO_2-equivalent per annum (or 5%) compared to 2017 levels;
- Operating costs have been within the benchmarks set – these savings have occurred during the first period in which we have operated under both an opex and capex incentive scheme;
- Made significant progress on Gas Vision 2050, including setting clear decarbonisation targets into the future; and
- Received conditional ARENA funding towards delivering the Hydrogen Parl Murray Valley project.

1.3 What we will deliver

Our Draft Plan for the next period builds on our strong performance over the current period. The activities and expenditure we propose to undertake in the next five years are summarised below.

Delivering for customers

- Responding to public leak reports within the timeframes set by the safety regulator more than 95% of the time;
- Improve customer satisfaction scores to be 8.2 or above;
- Laying reticulation mains and services, and installing meters, to connect around 69,000 new residential, business and industrial customers;
- Introducing a new Priority Services Program which will help us to recognise individual circumstances of our customers and provide them tailored support when they need it, and
- Providing more digital services and a greater variety of communication channels.

A good employer

- Continuing to target zero harm through workshops and embedding our HSE culture model;
- Continuing ongoing health and safety initiatives, including our various wellbeing initiatives;
- Targeting top quartile employee engagement scores, including to ensure our staff remain customer and safety focussed.

Sustainably cost efficient

- Delivering an upfront price cut of 8% (after inflation) on 1 July 2023, which builds on price cut delivered by our business in the current period. This reduction will result in savings over the period of:[1]
  - $22 per year for the average residential customer;
  - $76 per year for the average commercial customer; and
  - $1,900 per year for the average industrial customer;
- Maintaining combined operating and capital expenditure at current levels, while still continuing to provide the high level of service to a growing customer base;
- Taking steps to support the long-term future of the network in line with the decarbonisation goals of Victoria and Australia's energy sector, as well as our own plans, such as:
  - Keeping options open by accelerating $144 million of depreciation which will support the long-term competitiveness of the network to provide energy choice for customers in a net zero carbon future;
  - Investing $25 million in no regrets actions to ensure the network is ready for the distribution of hydrogen which includes updating procedures, replacement of incompatible parts, renewable gas

[1] This savings estimate assumes inflation of 1.5% per annum in years 2 – 5.

compatibility studies and a digital ultrasonic residential meter trial in the Albury/Wodonga region;

- Introducing a new Gas Network Innovation Scheme, which will provide $5 - 7.5 million in funding over the period that can be used to deliver innovative projects that are likely to deliver customer benefits, with any unspent funds passed back to customers; and
- Undertaking a renewable gas communications and education program which will help customers to feel confident today that renewable gas will be available in the future.

We believe this plan is consistent with the activities our customers expect over the next AA period. In saying this, this Draft Plan provides an important opportunity to seek further feedback from customers before we finalise our plan for the 5 year period commencing 1 July 2023.

2 Our Business

We deliver gas safely and reliably to more than 700,000 homes and businesses every year.

IN THIS CHAPTER:

- **AGN is part of AGIG, 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 Victoria and Albury is part of AGIG, one of the largest gas infrastructure businesses in Australia.

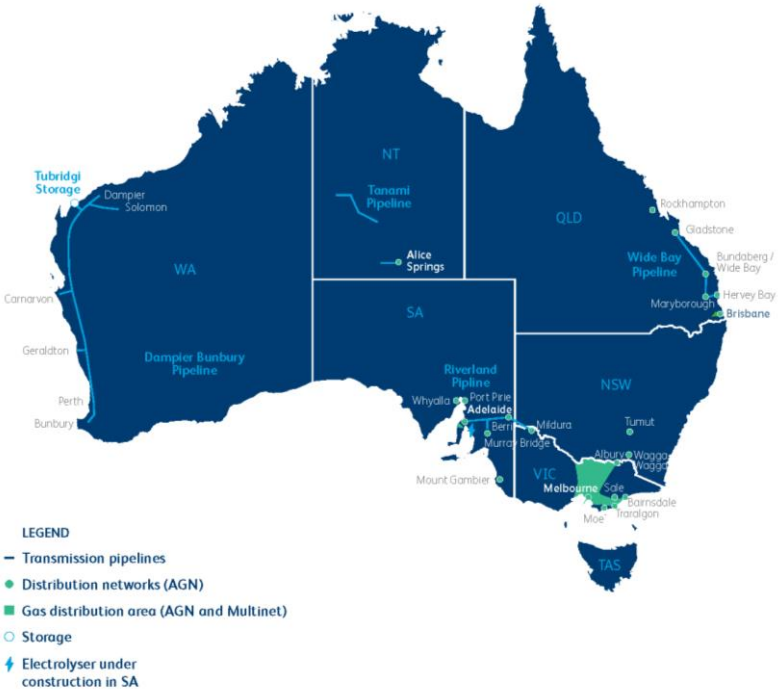
2.1 About AGIG

AGIG serves over two million customers across every mainland state and the Northern Territory. Our assets include around 34,900km of distribution networks, over 4,300km of transmission pipelines and 60 petajoules of storage capacity.

In 2017 AGN, Multinet Gas Networks (MGN) and Dampier to Bunbury (DBP) came together as a group, to form AGIG. The scale and expertise of AGIG is delivering enhanced benefits to AGN's customers in Victoria and Albury in the current AA period as outlined in Chapter 3.

AGIG is also leading the decarbonisation of gas supply in Australia. We are already injecting a 5% renewable hydrogen blend into part of our South Australian network, and we are working towards injecting a 10% hydrogen blend into our Albury and Wodonga network. Our low carbon strategy is described in section 2.8 below.

Figure 2.1 AGIG's operations across Australia



2.2 Our vision

Our vision is to be the leading gas infrastructure business in Australia. Our definition of leading is to achieve top quartile performance across all our key targets compared to other Australian gas infrastructure businesses.

To help achieve this vision, we have set ourselves the following objectives, which we believe are consistent with being the leading gas infrastructure business in Australia.

- *Delivering for customers* – this means ensuring public safety and the provision of high levels of reliability and customer service.
- *A good employer* – this means ensuring the health and safety of our employees and contractors, and having an engaged and skilled workforce.
- *Sustainably cost efficient* – this means getting the work done within benchmark levels by continually looking for ways to improve cost of service, pursuing growth, and ensuring we are environmentally and socially responsible in the way we provide services.

The activities and investments in this Draft Plan are designed to achieve these objectives. 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 against our vision, most recently in our 2020 Annual Review.

2.3 Our values

Our values of respect, trust, perform and one team drive our culture, how we behave and how we make decisions. As the owner and operator of critical infrastructure providing essential services to Australians, we must ensure we act with integrity and do the right thing for current and future customers.

Our vision

To be the leading gas infrastructure business in Australia. By achieving top quartile performance on our targets.

Delivering for customers

- Public safety
- Reliability
- Customer service

A good employer

- Health and safety
- Employee engagement
- Skills development

Sustainably cost efficient

- Working within industry benchmarks
- Delivering profitable growth
- Environmentally and socially responsible

Our values

Drive our culture: how we behave and how we make decisions.

Perform

We are accountable to our customers and stakeholders, we are transparent on our performance and we deliver results. We continously improve by bringing fresh ideas and constructive challenge.

Trust

We act with integrity, we do the right thing, we are safe guardians of essential Australian infrastructure. We act in a safe and professional manner.

Respect

We treat our customers and our colleagues the way we would want to be treated, and we embrace and respect diversity.

One Team

We communicate well and support each other, and we are united behind our shared vision.

2.4 Delivering for customers

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

The AGIG Disclosure Report developed under the Energy Charter is available at agig.com.au.

This commitment is consistent with our ongoing practice to engage with customers and stakeholders prior to providing our Final Plan to the AER. In developing this Draft Plan, we have engaged with customers through several activities. This engagement process has enabled customers and other stakeholders to inform and shape our proposals. The outcome of this process is explained throughout this document, while the stakeholder engagement program is detailed in Chapter 5.

2.5 Zero harm

Maintaining the safety of our workforce and the public is always front and centre in all our activities. When developing our Draft Plan and the work programs that underpin it, our aim is to do everything we can to continue to provide services in a safe and reliable manner.

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 rules 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. 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 through our Victorian and Albury distribution networks.

2.7 Our role in Victoria

Natural gas plays a pivotal role in Victoria by providing a reliable source of energy for homes, businesses and for power generation. Gas represents almost 22% of the total energy consumption in the state.

The following page shows the location and key features of our Victorian and Albury distribution networks. The network is more than 11,518 km long, serving residential, commercial and industrial business customers in the Melbourne CBD, northern, eastern and outer southern areas of metropolitan Melbourne, the Mornington Peninsula, and northern, eastern and south-eastern areas of Victoria.

A section of our distribution network (around 20,000 customers) extends into Albury in NSW, and operates within the Victorian Declared Wholesale Gas Market (DWGM).

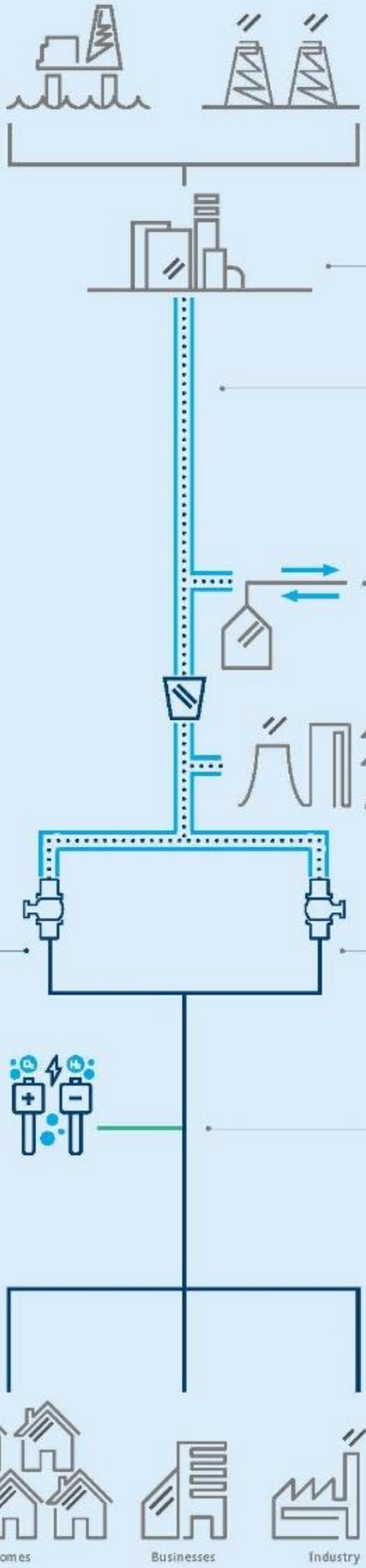
Our Services

We own and operate gas distribution infrastructure that delivers gas to Victorian homes and businesses.

We do not own the gas in our distribution networks, we deliver it on behalf of energy retailers and large customers across the gas supply chain.

The Gas Supply Chain

The process in which gas is produced and used; from the field to users.



Production and processing
Onshore and offshore gas fields are drilled to access gas reserves and gas is processed to specification.

Transmission
Transmission pipelines are large high-pressure pipelines which carry gas from the gas fields/processing plants to key markets (large users and distribution networks). At the end of transmission pipelines pressure is reduced before it enters the distribution network.

Storage
Gas storage facilities are used to store gas, including to balance fluctuations in gas demand.

Large users and power generation
Most large gas users such as industrial facilities and power generators connect directly to transmission pipelines to source gas for their operations.

Distribution
Gas from transmission pipelines is distributed via a network of lower pressure pipelines in towns and cities to customer sites.

Our distribution networks deliver gas directly to homes and small business customers, providing essential energy for hot water, heating and cooking for over two million customers. We are also responsible for reading the gas meter.

Renewable gas
The gas sector's vision for the future includes supplying renewable/carbon-neutral gas to customers. Biomethane and renewable hydrogen facilities are under development across the country.

Our **renewable gas facility** Hydrogen Park Murray Valley will begin production in 2024. We will supply this renewable hydrogen blended with natural gas to around 40,000 customers.

Retail
Residential, business and industrial customers buy gas from retailers. Retailers contract with gas producers, gas transmission pipelines and gas distribution networks to enable supply to customers. Retailers bill customers for providing these services.

- AGIG Services
- Non-AGIG Services

Australian Gas Networks

11,518
Kilometres of mains

56PJ
Gas delivered in 2020

712,063
Customers

8.7
Customer satisfaction score

2.8 Our low carbon strategy

Recognising the need for our assets to be sustainable in the long-term, AGIG is at the forefront of the emerging hydrogen industry in Australia. In 2017 we worked with Australia's five peak gas bodies to develop Gas Vision 2050 – a pathway to achieve near zero emissions in our gas sector.

We have developed a low carbon strategy, which includes the following targets:

- delivering 100% renewable gas developments from 2025;
- 10% renewable gas blend in networks by no later than 2030; and
- full decarbonisation of our networks by 2040 as a stretch target, but no later than 2050.

Our low carbon strategy is consistent with Gas Vision 2050, as well as Australian state and territory net zero ambitions, including Victoria.

We are now delivering on our strategy by deploying renewable gas projects. Hydrogen Park Murray Valley (HyP Murray Valley) was awarded conditional funding by the Australian Renewable Energy Agency. HyP Murray Valley is a key part of our vision to deliver for our customers and employees and to be environmentally and socially responsible.

Through HyP Murray Valley we expect to deliver 10% renewable hydrogen gas blend (by volume), produced with 100% renewable electricity[2] to around 40,000 residential, commercial and industrial customers in Albury and Wodonga. Along with our partner ENGIE, we are targeting a Final Investment Decision (FID) in 2022 and first production in 2024.

Hydrogen Park South Australia (HyP SA) is an Australian-first facility to supply blended renewable gas via the existing gas network. HyP SA is currently Australia's largest electrolyser and started production in May 2021. The 1.25MW unit produces renewable hydrogen which is blended up to volumes of 5% with natural gas and supplied to more than 700 existing homes in the adjacent suburb of Mitchell Park. It also supplies industry via tube trailer.

In Queensland at Hydrogen Park Gladstone we are building an electrolyser to produce renewable hydrogen for 10% blending with natural gas. This hydrogen blend will supply the entire network of Gladstone, including industry. First production is expected in 2022.

In Western Australia we have partnered with ATCO to deliver the Clean Energy Innovation Park which was also awarded conditional funding by ARENA in May 2021. This 10MW facility would produce renewable hydrogen for supply to gas network, transport and industrial customers. We are targeting FID in 2022 and first production in 2024.

In Western Australia we have completed a feasibility study into blending hydrogen into the Dampier Bunbury Pipeline – the first study in Australia to consider the potential for hydrogen blending in gas transmission pipelines.

Through the Australian Hydrogen Centre, we are developing feasibility studies to decarbonise gas distribution networks in Victoria and South Australia, including studies for 10% blending and 100% hydrogen networks in each state.

A detailed overview of hydrogen and renewable gas development is outlined in Box 1.

[2] AGIG will purchase (and voluntarily surrender) Large Scale Generation Certificates as required to ensure the electricity used to produce hydrogen is renewable.

Box 1: Hydrogen and renewable gas development

Hydrogen and other renewable gases represent a significant opportunity to achieve emissions reduction targets in a cost effective manner by making use of Victoria's existing gas networks. Renewable or 'clean' hydrogen can help decarbonise Australia's industry, transport and mining sectors.

For a number of AA periods now we have been replacing old low pressure cast iron and other material mains in our network. While this program of work is driven by safety considerations, it also means much of our network consists of modern polyethylene pipes which are compatible with the distribution of hydrogen.

In the future, clean hydrogen could also help firm the electricity grid as renewables reach very high levels, and provide an important source of controllable energy demand to increase power system resilience.

Australia's long-term emissions reduction plan 2021

Clean hydrogen has been identified as a priority low emissions technology – with a stretch target of clean hydrogen production under $2 per kilogram by 2035.

Australia's Hydrogen Strategy 2019

The National Hydrogen Strategy, which was released in December 2019, recognised the enormous potential of hydrogen for domestic use and export.

"*Domestic use of hydrogen will give us opportunities to expand into new and revitalised industries while helping us to develop the skills and credibility that will contribute to the development of our export industry*"

Victorian Renewable Hydrogen Industry Development Plan 2021

The Victorian Renewable Hydrogen Industry Development Plan released in 2021, sets out a blueprint for how the Victorian Government supports the growth of the emerging renewable hydrogen sector.

"We have a vision for renewable hydrogen to be a part of our economy and the transition to a net zero emission future"

"Victoria has the most extensive gas main network in Australia and uses a significant amount of natural gas. Renewable hydrogen could become a low carbon substitute for natural gas, either through gas blending or complete replacement in the long term"

National Gas Regulatory Reform: introducing hydrogen and renewable gas

The national gas regulatory framework, does not currently contemplate hydrogen blends, which means the regulation of hydrogen blends and renewable gas is uncertain under the current arrangements.

In August 2021 Commonwealth, State and Territory Energy Ministers agreed to reform the national gas regulatory framework to bring hydrogen blends, biomethane and other renewable gases within its scope, with an initial focus on gases and blends that can be used in existing natural gas appliances. Jurisdictional Officials, the Australian Energy Market Commission and the Australian Energy Market Operator have all commenced concurrent consultations reviewing various areas of the regulatory and market frameworks (National Gas Law, National Gas Retail Law, Regulations, National Gas Rules, National Gas Retail Rules and AEMO Procedures).

If these reforms proceed, this will enable hydrogen blends and other renewable gases to be recognised by the national gas regulatory framework, including extending the functions and powers of the AER and other market bodies in the NGL so that they will be able to exercise their functions and powers with respect to low level blends of hydrogen and renewable gas, just as they currently do with respect to natural gas.

The reforms will also enable hydrogen blends and other renewable gases to participate in wholesale markets. In terms of timing, the draft legislative package is aimed to be presented to Ministers for approval by mid-2022 and draft rules in the latter half of 2022.

Victorian program of hydrogen and renewable gas regulatory reforms

The *National Gas (Victoria) Act* was recently amended to introduce a new power which enables the Minister for Energy to declare hydrogen, hydrogen blends and other renewable gases as 'natural gas' for the purposes of the National Gas Law as it applies in Victoria. This is an interim step until the national gas regulatory framework reforms outlined above are developed and implemented.

Also, the Australian Energy Market Commission (AEMC) has initiated a rule change process for the National Gas Rules applying to the Victorian gas market in response to a request by the Victorian Energy Minister. The rule change will allow hydrogen and biogas production facilities as well as others such as storage facilities to directly connect into the gas distribution network.

3 Our track record

In the 2018 to 2022 period we have continued to deliver the strong safety, reliability and service standards expected by our customers.

IN THIS CHAPTER:

- **We are on track for our highest customer satisfaction score again in 2021 of 8.7, following continued improvement in scores over the period.**
- **We have delivered real opex savings of around 4% compared to our benchmarks, while also connecting nearly 88,000 new customers. Both the cost savings and the new connections will benefit customers through lower prices in the next period.**
- **Despite major challenges, we are on track to complete the replacement of all low pressure mains, including the very complex Melbourne CBD program. This is a significant safety milestone for our customers and our business and will deliver ongoing reported scope 1 emissions reductions of 13,500 tonnes of CO_2-equivalent per annum (or 5%) compared to 2017 levels.**

Our focus in the current period has been on maintaining the safety and reliability of the network through completing the replacement of all of our old low pressure mains – a significant safety milestone for our customers and our business, improving customer service, and minimising costs.

In accordance with our vision, our aim is to be the leading gas infrastructure business in Australia by achieving top quartile performance on all of our key targets.

Our activities throughout the current period have been guided by our key objectives of delivering for customers, being a good employer and remaining sustainably cost efficient. For the 2018 to 2022 period, we set a number of targets that we could use to measure how we have delivered against our vision. These targets were shared in our Final Plan for Victoria and Albury in December 2016. Figure 3.1 below summarises our performance in the current period to date against these targets.

Overall, we have achieved strong performance against our vision, met the key safety standards set for the business and delivered the major outputs set by the AER.

3.1 Delivering for customers

We deliver for customers by ensuring public safety, reliability and customer service.

Our 2018 to 2022 targets included maintaining high performance levels, improving safety, maintaining reliability, supporting customer growth, engaging on our plans and improving and strengthening network incentives.

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

- Repairing 99% of leaks within the timeframes set by the safety regulator;
- Answering 93% of Emergency calls within 10 seconds;
- Investing $128 million to connect nearly 52,000 new customers to our network (99% of the time within 20 days);
- Completing 166 kilometres of low pressure mains replacement to June 2021, and being on track to complete the replacement of old, low pressure mains by the end of the period (see also 'Sustainably cost efficient');
- Improving our customer satisfaction scores to 8.7 in 2021, following continued improvement in our scores over the period; and
- Operating under the Efficiency Benefit Sharing Scheme and the contingent Capital Expenditure Sharing Scheme.

3.2 A good employer

To be a good employer we focus on the health and safety, engagement and skills and training of our workforce.

Our 2018 to 2022 targets were focused on continuous improvement, including Lost Time Injury Frequency Rate (LTIFR) less than 1.0 per million hours, restricted duties rate less than 15 days, 78% employee engagement, and training and compliance monitoring.

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

- Adopting a new approach to tracking health and safety, with Total Recordable Injury Frequency Rate (TRIFR) averaging 9.9 since we began tracking this metric in 2018 and bringing the number of Lost Time Injuries (LTIs) from three per annum down to two per annum;
- We have introduced a number of health and safety initiatives aimed at continuous improvement including a refresh of our Zero Harm principles, annual Zero Harm workshops, a HSE culture model and reporting, and HSE recognition awards;
- Employee engagement scores have remained at or near the top quartile for our industry, averaging 69%; and
- Above 90% of compliance training has been completed within the required timeframes.

3.3 Sustainably cost efficient

To be sustainably cost efficient we focus on working within industry benchmarks, delivering profitable growth and being environmentally and socially responsible.

Our 2018 to 2022 targets included completion of low pressure mains replacement (297 kilometres), delivering lower network tariffs in real terms and continuing to deliver leading productivity performance (by lowering expenditure relative to current levels).

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

- completing 166 kilometres of low pressure mains replacement to June 2021, including 29 kilometres within the Melbourne CBD. While this has been one of our biggest challenges in this period in terms of complexity and cost, we are on track for completion of all 297 kilometres – which will complete the low pressure replacement program – by the end of the period;
- Completion of the low pressure mains replacement program is a significant safety milestone and has the added benefit of making the network hydrogen ready. Completion of the program also delivers environmental benefits today, reducing our reported scope 1 emissions – as calculated under the National Greenhouse and Energy Reporting scheme – by a further 13,500 tonnes of CO_2-equivalent per annum (or 5%) compared to 2017 levels;
- We delivered a real price cut of 7% on 1 July 2018; and
- Our opex continues to benchmark favourably against our peers and we have lowered our opex further in the current period with actual opex forecast to be 4% below our allowance in real term.

Figure 3.1: Our performance against our vision in the current period (2018 to date, with forecast performance to the end of the period where applicable)

Vision	Vision	Vision
Delivering for customers	A good employer	Sustainably cost efficient
Which means	**Which means**	**Which means**
• Public safety • Reliability • Customer service	• Health & Safety • Employee Engagement • Skills Development	• Working within industry benchmarks • Delivering profitable growth • Environmentally and socially responsible
Our performance 2018 to date	**Our performance 2018 to date**	**Our performance 2018 to date**
• 99 % of high priority leaks repaired within the timeframes set by the safety regulator • Maintained strong reliability performance • 93 % of emergency calls answered within 10 seconds • Around 17,000 new connections per annum, with 99 % complete within the required 20 days • Customer satisfaction survey scored an average of 8.2, with our highest score to date of 8.7 in 2021 • First full period operating under the new contingent Capital Expenditure Sharing Scheme	• New approach to tracking health and safety, with Total Recordable Injury Frequency Rate (TRIFR) averaging 9.9 since we began tracking this metric in 2018 • Lost Time Injuries (LTIs) reduced from three per annum to two per annum • Employee engagement annual average score of 69 %, remaining at or near the top quartile of our industry every year • Compliance training: >90 % per cent	• 5 % upfront price cut on 1 July 2018 • Mains replacement: on track to complete low pressure mains replacement program (297 kilometres) in line with approved targets – including the Melbourne CBD mains replacement, despite challenges • Operating costs have been within the benchmarks set for the business, with real savings of around 4 % • Made significant progress on Gas Vision 2050 and set clear decarbonisation targets over the next 20 years • Reported scope 1 emissions reductions of a further 13,500 tonnes CO2-e pa (or 5 %) compared to 2017 levels related to the completion of the low pressure mains replacement program

4 What we will deliver

This Draft Plan supports our vision to be the leading gas infrastructure business in Australia by delivering affordable, safe, reliable and sustainable gas distribution services

IN THIS CHAPTER:

- **An upfront price cut of 8% (after inflation) on 1 July 2023 building on the 5% price cut (after inflation) delivered on 1 January 2018.**
- **We will connect around 69,000 new customers, with our total customer base expected to reach 800,000 by the end of the period.**
- **We will invest around $26 million to support the transition of our network to deliver renewable gases in line with the decarbonisation goals of Victoria and Australia's energy sector, as well as our own plans to achieve 10% renewable gas by volume by 2030 and 100% renewable gas by 2040.**

We have engaged with customers in Victoria and Albury to develop our Draft Plan for the five-year period 2023/24 to 2027/28. Their insights have shaped our plans and will ensure we continue to provide affordable, safe, reliable and sustainable gas distribution services today and for the future.

Our vision is to be the leading gas infrastructure business in Australia by achieving top quartile performance on all of our key targets.

Our Draft Plan presents further reductions in our prices by investing efficiently in our assets and operations. Highlights of what we will deliver in the next AA period are included in Figure 3.1 and described in more detail in the sections that follow.

4.1 Delivering for customers

- Delivering for our customers means ensuring public safety and high levels of reliability and customer service.
- Our customers expect and trust us to maintain the safety and reliability of the network. In the next period we will deliver for customers by:
  - Responding to public leak reports within the timeframes set by the safety regulator more than 95% of the time;
  - Maintaining customer satisfaction scores of 8.2 or above;
  - Laying reticulation mains and services, and installing meters, to connect around 69,000 new residential, business and industrial customers;
  - Introducing a new Priority Services Program which will help us to recognise individual circumstances of our customers and provide them tailored support when they need it, and

- Providing more digital services and a greater variety of communication channels.

4.2 A good employer

Being a good employer means prioritising the health and safety of our employees, focussing on employee engagement and skills development.

Investing in our workforce helps ensure we can continue to deliver services that meet our customers' expectations.

In the next period we will be a good employer by:

- Continuing to target zero harm through workshops and embedding our HSE culture model;
- Continuing ongoing health and safety initiatives, including our various wellbeing initiatives;
- Targeting top quartile employee engagement scores to ensure our staff remain customer and safety focussed.

4.3 Sustainably cost efficient

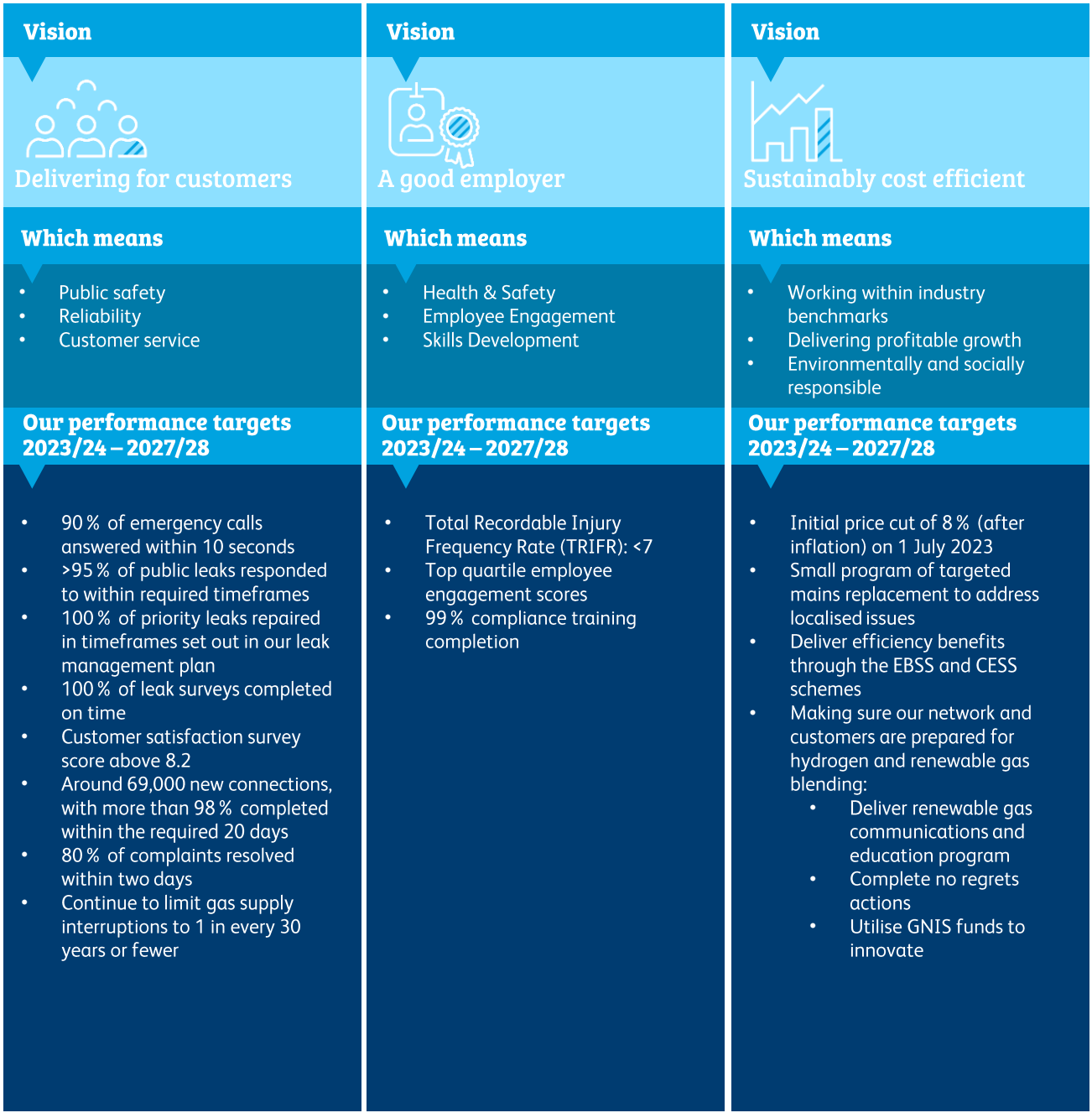
Being sustainably cost efficient means working within industry benchmarks, delivering profitable growth and being environmentally and socially responsible.

In the next period we will be sustainably cost efficient by:

- Delivering an upfront price cut of 8% on 1 July 2023, which builds on price cuts delivered by our business in the current period. This reduction will result in savings over the period of[3]:
  - $22 per year for the average residential customer;
  - $76 per year for the average commercial customer; and
  - $1,900 per year for the average industrial customer;
- Maintaining combined operating and capital expenditure at current levels, despite our network growing in size and customer numbers;
- Taking steps to support the long-term future of the network in line with the decarbonisation goals of Victoria and Australia's energy sector, as well as our own plans, such as:
  - Keeping options open by accelerating $144 million of depreciation which will support the long term competitiveness of the network to provide energy choice for customers in a net zero carbon future;
  - Investing $25 million in no regrets actions to ensure the network is ready for the distribution of hydrogen which includes updating procedures, replacement of incompatible parts, renewable gas compatibility studies and a digital ultrasonic residential meter trial in the Albury/Wodonga region;
  - Introducing a new Gas Network Innovation Scheme, which will provide $5 - 7.5 million in funding over the period that can be used to deliver innovative projects that are likely to deliver customer benefits, with any unspent funds passed back to customers;
  - Undertaking a renewable gas communications and education program which will help customers to feel confident today that renewable gas will be available in the future.

[3] This savings estimate assumes inflation of 1.5% per annum in years 2 – 5.

Figure 4.1: Our performance targets for the 2023/24 to 2027/28 period



5 Customer and Stakeholder Engagement

This Draft Plan has been developed collaboratively with customers and stakeholders as part of an extensive engagement program. Customer and stakeholder input and feedback is integrated into every aspect of this Draft Plan to ensure we deliver valued services for Victorians, now and in the future.

IN THIS CHAPTER:

- **We consulted widely on our proposed engagement approach and are delivering a joint engagement program with AusNet Services and Multinet Gas Networks.**
- **We established the Victorian Gas Network Stakeholder Roundtable (VGNSR) to inform, shape and challenge us in the development of our Plans.**
- **We held iterative workshops with key customer groups to understand their needs and preferences, including residential, business, culturally and linguistically diverse (CALD) customers, major gas users, and customers experiencing vulnerability.**
- **We designed and delivered bespoke engagement activities for key issues of importance: future of gas, and services for customers in vulnerable circumstances.**

We have undertaken extensive engagement with our customers and stakeholders in the development of this Draft Plan.

We have done this, and will continue to do this, to ensure that our plans deliver on what matters the most to our customers.

This Draft Plan outlines how our engagement activities have informed and shaped our proposals to date. It also provides further opportunity for input into the development of our Final Plan.

This Chapter explains our customer and stakeholder engagement program, activities undertaken, feedback we received, and how this feedback has influenced our plans.

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 capable of acceptance by our customers and stakeholders.

We adopted a four staged approach to our engagement program which is illustrated in Table 5.1.

In the development of this Draft Plan we have completed stages one and two of our engagement program.

This chapter describes how we engaged with key stakeholders on the development of our engagement approach and program, including the formation of our joint Victorian engagement program with AusNet Services and Multinet Gas Networks.

This chapter outlines our engagement approach, principles, methodology and timeline.

It also documents and describes the engagement activities we have undertaken and how we have responded in this Draft Plan including:

- Seven meetings of the VGNSR and Retail Reference Group;
- Two phases of customer workshops with over 150 AGN customers from metropolitan and regional Victoria and Albury, NSW;
- Four workshops with culturally and linguistically diverse (CALD) customers in Shepparton and Melbourne CBD in partnership with Ethnic Communities Council of Victoria (ECCV);
- Two forums with major gas users in collaboration with Energy Users Association of Australia (EUAA) and Australian Industry (Ai) Group;
- Six meetings of the Future of Gas Expert Panel, four of which were dedicated to a co-design process; and
- Two workshops with the Priority Service Advisory Panel to develop.

Critical to our program has been the ongoing engagement with our two stakeholder reference groups through a series of meetings and workshops.

Membership of VGNSR reflects the diversity of our customer base, with organisations representing residential customers, vulnerable customers, multicultural communities, business and industrial customers, builders and developers, and local government.

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

Through seven meetings and workshops we consulted with stakeholders on topics including:

- our pipeline services;
- customer experience and flexible solutions;
- our prices
- our capex and opex proposals;
- demand forecast;
- rate of return;
- incentives;
- setting our capital base; and
- future of gas

A list of engagement topics discussed at meetings and workshops is shown in Table 5.3 of this chapter.

Table 5.1: Our Four Staged Approach to Engagement

Stages 1 and 2 of engagement are now complete >

Stage 1 Strategy and research	**Stage 2** Developing our Draft Plan	**Stage 3** Consultation on our Draft Plan	**Stage 4** Refinement and engagement
Feb - Apr 2021	**May - Dec 2021**	**Jan – Feb 2022**	**Feb - Jul 2022**
Purpose Engaging with stakeholders to better understand customer needs and to consult on our proposed engagement approach.	**Purpose** Running a series of engagement activities designed to inform the development of our Draft Plan.	**Purpose** Focusing on public consultation on our Draft Plan.	**Purpose** Finalising our plan and incorporating feedback received during consultation on the draft.
IAP2 Spectrum CONSULT/INVOLVE	**IAP2 Spectrum** INVOLVE/COLLABORATE	**IAP2 Spectrum** CONSULT/INVOLVE	**IAP2 Spectrum** INFORM/INVOLVE/CONSULT
Engagement Activities • Meetings with key stakeholders • Publish and consult on a Draft Engagement Plan • Establish a Victorian Gas Networks Roundtable • Engage with the Retailer Reference Group • Establish partnership opportunities with stakeholder organisations (e.g. ethnic communities) • Establish online portal	**Engagement Activities** • Series of Victorian Roundtable meetings • Series of Retailer Reference Group meetings • Iterative customer workshops across Victoria with key customer segments (metro and regional) • Future of Gas Expert Panel co-design workshops • Gas Major User Forums • Meetings with the Property Industry and Gas Plumbers • Priority Services Program workshops with Advisory Group	**Engagement Activities** • Publish Draft Plans for AGN, Ausnet & MGN for a 6 wk consultation period • Customer workshops to consult on Draft Plan • Combined deep dive workshops for Victorian Roundtable and Retailer Reference Group meetings • Future of Gas Expert Panel co-design workshop to consider feedback on scenarios • Gas Major User Forum • Meeting with the Property Industry • Priority Services Program workshop with Advisory Group	**Engagement Activities** • Combined deep dive workshops for Victorian Roundtable and Retailer Reference Group meetings • Future of Gas – Dedicated engagement activities • Undertake post-lodgement engagement activities • Meetings/briefings with key stakeholders (e.g. AER Consumer Challenge Panel)
Key Deliverables: **Final Engagement Report** A report summarising and responding to feedback and including a Final Joint Engagement Plan.	**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 & Future of Gas Engagement Activities.	**Key Deliverables:** **Draft Plan** Summary tables/report of all feedback on key areas/issues for further engagement in Stage 4.	**Key Deliverables:** **Final Plans to the AER** Submission of Final Plans for AGN, Ausnet & MGN with supporting customer and stakeholder engagement reports.

5.2 Our Engagement Approach

On 19 February we published our Draft Engagement Plan for a six-week consultation period. We distributed the draft engagement plan widely and invited key stakeholder groups to provide feedback.

This is an important step in our four staged approach to ensure we engage with the relevant stakeholders and they had an opportunity to input into our proposed engagement activities.

We sought feedback on our proposed engagement strategy, including our proposed approach to stakeholder engagement, identification of key stakeholders, proposed engagement activities and the timeline.

We also sought to understand what is important to our customers and stakeholders – and what topics they wanted to be engaged on.

In February and early March 2021, we held one-on-one consultation meetings with the Australian Industry (Ai) Group, Ethnic Communities' Council of Victoria (ECCV), Energy Users Association of Australia (EUAA), St Vincent de Paul, Australian Energy Council, Energy and Water Ombudsman of Victoria (EWOV), and the Victorian Council of Social Services (VCOSS) to discuss our proposed approach and explore key issues for engagement.

A summary of feedback we received on our Draft Engagement Plan and how we have responded is included in Table 5.2.

Three Gas Network Business, One Engagement Program

In mid-2020, we engaged in early discussion with AusNet Services on opportunities to work more collaboratively on our regulatory resets in the interests of our customers and stakeholders.

We identified the opportunity to design and deliver a joint program with key activities delivered in partnership featuring:

- Consistent engagement methodology for all Victorian gas customers
- One engagement plan, with consistent timelines and key milestones
- A single customer and stakeholder roundtable to provide one forum for consumer advocates to attend rather than three separate ones
- Joint engagement projects on key issues of importance of commonality across networks, in particular future of gas and services for customers experiencing vulnerability
- Consistent engagement KPIs and reporting
- One online engagement portal

During consultation on our Draft Engagement Plan, we received very positive stakeholder feedback. Stakeholders highlighted that the joint approach promotes consistency and coordination across the networks and provides a single forum to discuss issues of importance to the sector. Consumer advocates noted the efficiency in reducing the number of consumer consultative panels and the benefit of having one platform to engage on issues relating to gas distribution for all Victorians.

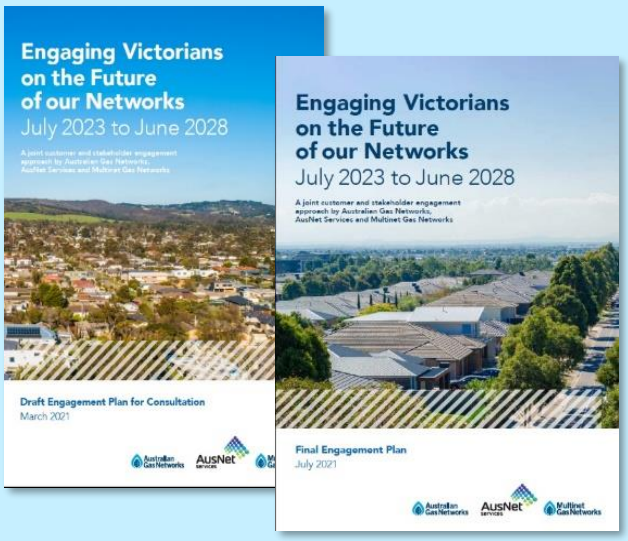


Table 5.2: Customer and stakeholder feedback on our Engagement Plan

Customer and stakeholder feedback	Our response
Our Engagement Approach	
• Stakeholders supported AGN, AusNet and MGN's shared objectives, being to develop a plan capable of acceptance, deliver for current and future customers, and be underpinned by effective customer and stakeholder engagement. • Stakeholders were supportive of our joint engagement approach and noted the efficiencies and effectiveness in providing a single forum for consumer advocates to engage with gas distribution businesses. • Stakeholders were keen to ensure the objective of a "plan of capable acceptance" was regularly discussed at stakeholder meetings.	• We have confirmed our four stage approach to develop our Final Plan. • We have confirmed our commitment to our engagement principles and a no surprises approach. • We have committed to working with MGN and AusNet to deliver an engagement program for all Victorians. • We have incorporated discussions around how we are progressing against our objective of a "plan capable of acceptance" into upcoming VGNSR, RRG and Consumer Challenge Panel meetings.
Our Principles	
• Stakeholders requested that we include "accountability" as an engagement principle.	• "Accountability" has been incorporated into the "measurable" principle underpinning our engagement program.
Key Stakeholders	
• Stakeholders suggested we expand our activities to include engagement with the following customer and other stakeholder groups: gas appliance manufacturers, developers, contractors, special-interest user groups (such as chemical manufacturers and food processors), First Nations People and social service organisations.	• We have revised our stakeholder map. • The Gas Appliance Manufacturers Association of Australia (GAMMA) was invited to participate on our VGNSR to ensure that their perspective is considered as we developed our Plans. • We briefed Australian Pipelines and Gas Association (APGA) on our engagement program and invited their participation / feedback. • We established the PSP Advisory Group which comprises of a broad range of social service organisations. We have also invited Brotherhood of Saint Laurence, VCOSS and St Vincent de Paul onto our VGNSR. • We have explored opportunities to engage with First Nations People through the PSP Advisory Group.
Our Engagement Activities	

• Stakeholders requested details on:
  • Future of Gas Co-Design, including the process that we had proposed, what topics would be addressed, the format and who will be involved.
  • Customer workshop specifics, including when they will be held and what groups of customers will be invited to each.
	• We committed to providing regular updates on the Future of Gas co-design work to VGNSR and RRG during our regular meetings. We also held a dedicated session on the Future of Gas with the VGNSR to brief them in more detail.
	• We are sharing all output from the Future of Gas co-design process with the VGNSR and RRG members and online via Gas Matters.

Table 5.2: Customer and stakeholder feedback on our Engagement Plan (cont.)

Customer and stakeholder feedback	Our response
Our Engagement Activities (cont.)	

• Stakeholders suggested changes to:
  • Customer workshops locations to include the northern Melbourne metro growth channel.
• Stakeholders suggested expanded or additional engagement with:
  • Major Gas Users
  • Customers Experiencing vulnerability
  • Property Developers and Contractors
	• We provided the VGNSR with the opportunity to have input into our customer workshop methodology.
	• We are providing regular updates on our customer workshop logistics and insights at VGNSR and RRG meetings.
	• We are sharing all presentation materials and output from our customer workshops on Gas Matters.
	• We expanded our engagement with major gas users to include dedicated forums and surveys.
	• We added engagement activities with property developers and contractors.
	• We identified that one-on-one meetings could be undertaken with interested environmental advocates.
	• We are undertaking dedicated PSP workshops with social service organisations to explore how we better support customers experiencing vulnerability in Victoria.

Timeline	
• Stakeholders asked that we provide more detail on the timeline for engagement activities, including any engagement we plan to do post-lodgement.	• We updated and expanded our timeline to include proposed dates for each engagement activity, as well as activities planned for engaging on our Draft Plan and Final Plan post-submission in July.

Overall, we received positive feedback regarding our proposed engagement approach.

Stakeholders were keen to ensure the objective of developing a plan "capable of acceptance" remains a strong focus throughout our engagement activities.

All stakeholders provided positive feedback on the proposed staged approach, engagement principles, the proposed timeline and proposed KPIs. We did receive feedback that we should provide more detail on post lodgement engagement which is included in our Final Engagement Plan.

In regard to key engagement activities, stakeholders identified opportunities for further engagement with key customer groups and industries as illustrated in Figure 5.2.

Feedback regarding topics for engagement are discussed in Section 5.5 of this chapter.

Feedback from stakeholders was used to inform our Final Engagement Plan.

5.3 Our Engagement Principles

We have adopted a series of engagement principles as shown in Figure 5.1. These principles guide how we engage with our customers and stakeholders.

5.4 Our Customers and Stakeholders

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

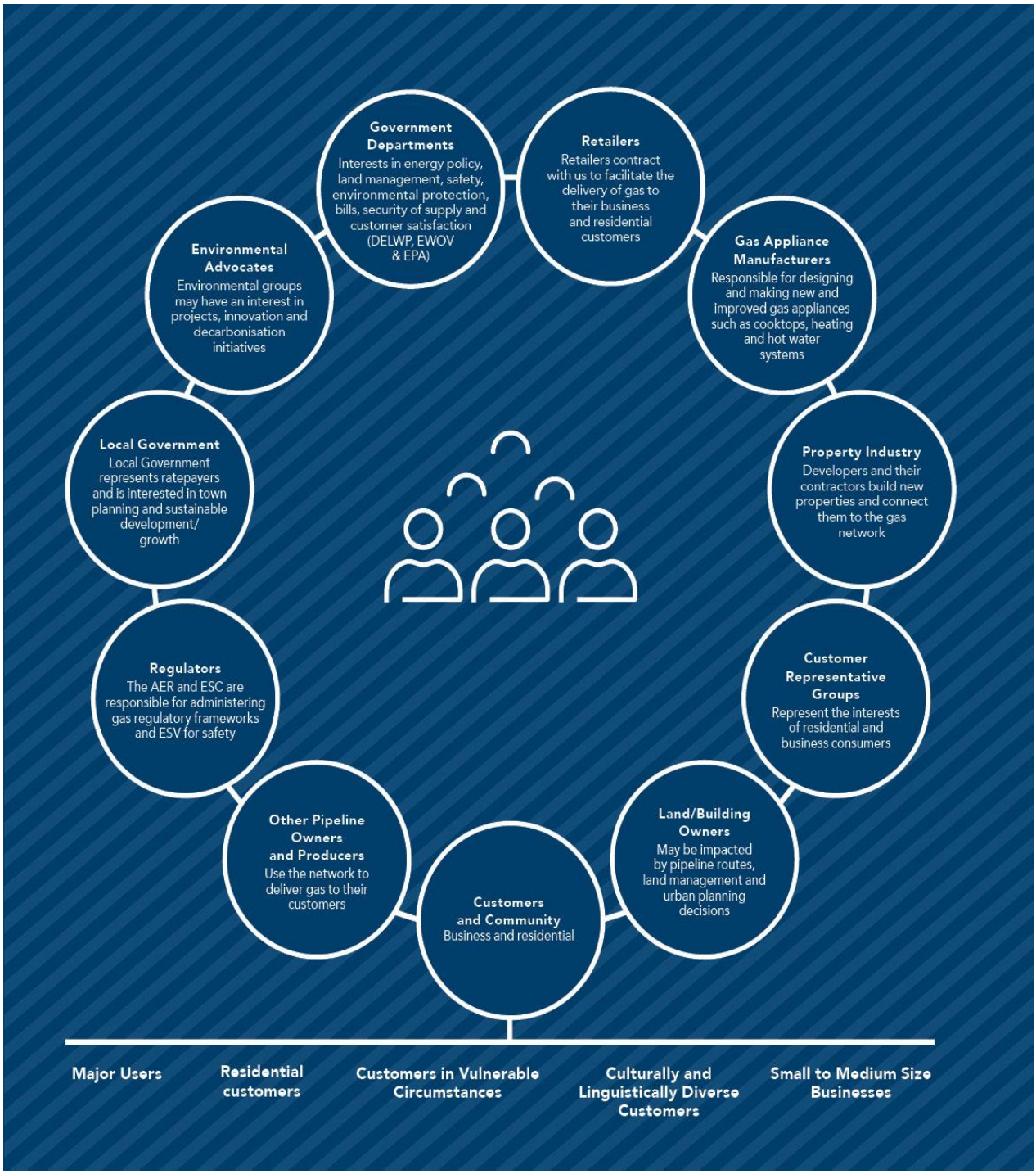
In the early stages of engagement, we consulted with key stakeholders and sought feedback on who should be involved, to ensure that we involve all relevant stakeholders.

Figure 5.1: Our Engagement Principles

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

Our key stakeholder groups are illustrated in Figure 5.2.

Figure 5.2: Our customers and stakeholders



5.5 Key topics for engagement

Our engagement program covers a broad range of often complex topics. In developing the list of topics (see Table 5.3), 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 distinguishable feature of this engagement program is the interest in, and importance of, discussions on the future of gas, particularly in light of actions taken by the Victorian Government to address the decarbonisation of gas to reach its net zero emissions targets.

We know that the Victorian energy sector is undergoing rapid transformation driven by a range of factors, including decarbonisation. When compared to the electricity sector, the decarbonisation pathway for gas is less certain and if left unaddressed could reduce the relevance of gas in the future energy mix.

Future of gas was identified as a critical topic for engagement as stakeholders are keen to understand:

- How decisions we make today will impact customers in the future;
- What renewable gas could mean for customers in the energy transition (e.g. appliances, costs); and
- The potential role gas will play in a low carbon future, and how to best consider and respond to uncertainty.

Table 5.3: Key Topics for Engagement

Key topics
Future of Gas
• Renewable gas opportunities
• Government policy impacts
• Future energy scenarios
• Customer impacts/ transition to renewable gas
• Gas appliances
• Development impacts / opportunities
• Demand impacts
• Long term planning (beyond 5 year reset)
Price and Affordability
• Price Paths
• Intergenerational equity
Customer Service and Experience
• Services for customers experiencing vulnerability
• Digital services
Public Safety
Reliability of Supply
Mains Replacement
Innovation
Impacts of COVID-19
Regulatory Building Blocks
• Pipeline services
• Capital base
• Depreciation
• Demand forecasting
• Capex & Opex proposals
• Incentives
• Revenue & Pricing

5.6 Engagement Activities & Feedback

5.6.1 Customer Engagement

Engaging directly with customers in the development of this plan is critical to ensure that we align our plans and proposals with customers' needs and expectations.

A summary table of customer feedback is included in Table 5.11, with more detail on methodology and key insights in this section.

Customer Workshop Methodology

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

To date we have completed two phases of workshops – in July and September 2021 - which have been used to shape these plans.

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

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

COVID Safe Engagement

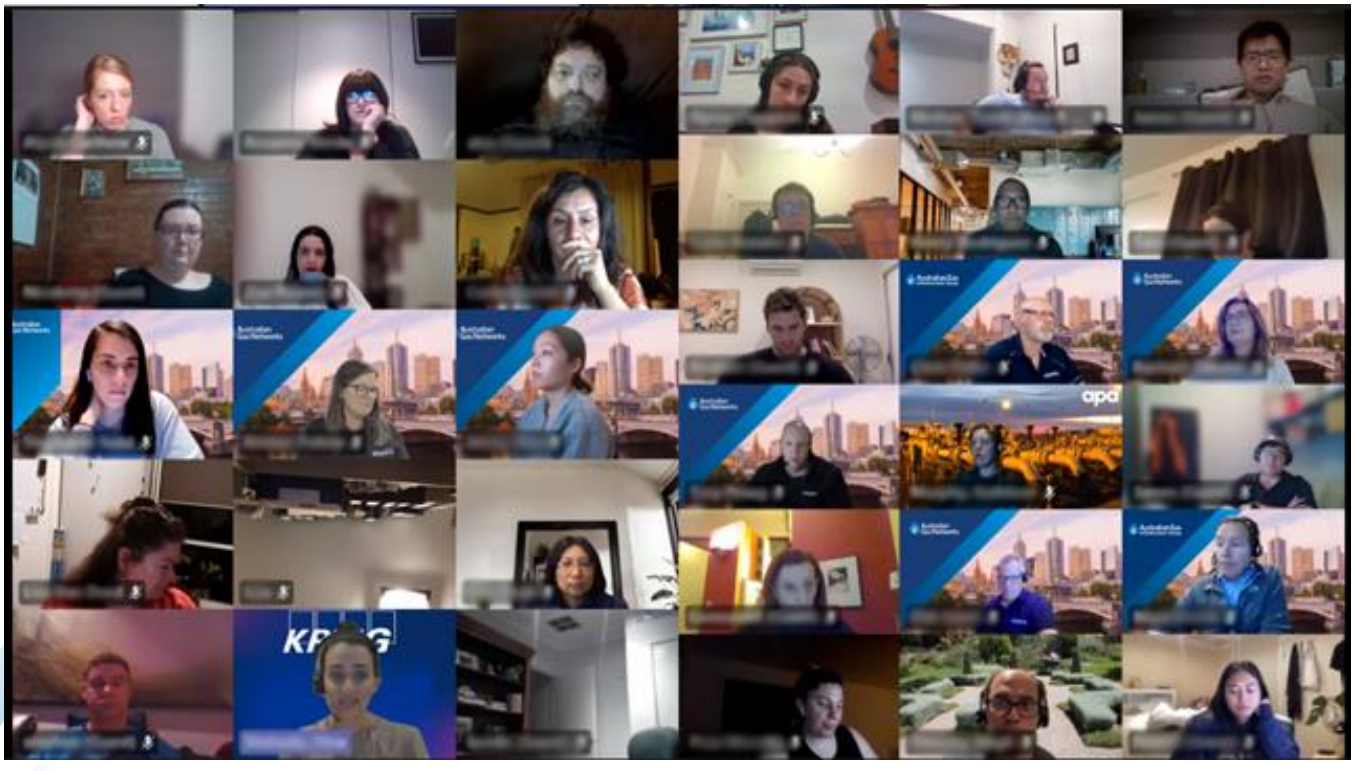
The COVID-19 pandemic has created some challenging conditions in which to undertake customer and stakeholder engagement activities.

The health and safety of our community and staff is our number one priority and will continue to undertake our engagement activities in a manner which is compliant with government health advice and regulations. With this in mind, we are hopeful that we will be able to deliver more engagement face-to-face in 2022.

While our preference was to hold the customer workshops face-to-face, owing to COVID-19 restrictions in place at the time, the first two phases were held online. We engaged with customers living across six locations in Victoria with a total of 164 (phase 1) and 117 (phase 2) participants attending across seven dedicated workshops. See summary table below.

Workshops consist of a mix of residential, small business,

Figure 5.3. AGN customers and AGN staff participating in the second round of customer workshops via MS Teams



metropolitan, regional and CALD customers.

Participants were recruited through a specialist third party provider and represented a broad cross section of the community.

We partnered with ECCV and Ethnic Council of Shepparton & District Inc. to hold dedicated workshops with CALD customers in the CBD and regional Victoria.

Customer workshops were facilitated by a third party (KPMG) to provide independence in how customer feedback was captured and documented.

We utilised a range of digital techniques to ensure that online workshops were engaging and interesting, including presentations from subject matter experts, online polling and surveying. We utilised the chat function within the digital platform to answer any customer questions as they arose, meaning that customers felt informed throughout the discussion.

Phase 1 Customer Workshops: Objectives, engagement activities, and results

The objectives of Phase 1 customer workshops were to:

- ✓ Educate customers about AGN and its role, to facilitate ongoing engagement at phase 2 and 3 workshops
- ✓ Understand customer values, service expectations and priorities to inform future investment plans
- ✓ Engage with, and listen to customers to understand issues of importance

Phase 1 workshops were 2 hours in duration and held online. AGN presenters and subject matter experts were available throughout the session to respond to questions. We used online break out rooms, surveying and quizzes to keep the workshop interesting.

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

Key topics, information presented and insights from Phase 1 are illustrated in Table 5.5.

Table 5.4: Workshop location, customer segments and attendance

Location	Customer Segment	Phase 1 Attendance	Phase 2 Attendance	Return Rate (%)
Melbourne CBD	CALD customers	21	17	81
Melbourne CBD	Residential and business customers	23	17	74
Shepparton	CALD customers	21	12	57
Richmond	Residential customers	25	19	76
Pakenham	Residential customers	21	16	76
Traralgon	Residential and business customers	20	18	90
Wodonga	Residential and business customers	33	18	55
	TOTAL	**164**	**117**	**71**

Table 5.5: Customer workshop summary feedback

Theme	Engagement Activity	Key Insights and Results
	Phase 1 Customer Workshops	

 **Get the basics right**	• We provided an overview of our business and role in the energy supply chain and how we maintain the network
	• Engagement activities:
	  • How important is it to you that your gas supply is reliable?
	  • Why is it important to you that your gas supply is reliable?
	  • What does public safety mean for you?
	  • Over the past 5 years, how satisfied have you been with public safety and reliability?
	  • What does great customer service look like?
	•
		✓ Customers value their current gas supply and expect levels of public safety and reliability to be maintained.
		✓ Customers consider gas as an essential service, especially for heating in the colder months in Victoria.
		✓ After price, reliability and safety are the top two priorities for customers. Although price is a top priority, customers are adamant lower prices should not compromise safety or reliability.
		✓ Customers view safety as a non-negotiable.
		✓ 93% of customers are satisfied or very satisfied with the reliability of their gas supply.
		✓ Customers trust that AGN are getting the basics right
		✓ When customers interact with AGN they expect responsive and effective resolution.
		✓ When communicating with AGN, customers expect professionalism, respect, simple and clear language, empathy and patience.
		✓ Customers prefer phone for priority services like a gas leak, whereas digital communications (SMS) are preferred for updates on outages and new connections.

	Phase 2 Customer Workshops	

	• We presented our current performance on reliability and safety of our network and proposed mains replacement.
	• We presented current customer service performance and CSAT scores.
	• We presented proposed options to test customer needs for improved digital services (e.g., SMS, online services)
	• Engagement Activity:
	  • How comfortable are you with AGN's approach to maintain current levels of reliability and safety?
	  • Which digital package of services do you think is best value and why? (3 options tested)
		✓ 88% of customers supported AGN's proposed approach to maintain current safety and reliability performance, with 11% of customers asking for more information to be able to make a decision.
		✓ Many customers provided positive feedback regarding current performance on call answering times and AGN's on shore call centres.
		✓ SMS for communications and customer service appeals to many customers for convenience and the ability to receive instant notifications.
		✓ SMS is a high valued communication tool by CALD customers and senior Australians.
		✓ 57% of customers support investment in SMS technology for communications at $2.50 p.a bill impact. The remaining 43% supported website and email questioning costs given low frequency of interactions.

Table 5.5: Customer workshop summary feedback (cont.)

Theme	Engagement Activity	Key Insights and Results
Focus on the future 	**Phase 1 Customer Workshops**	

	• We provided an overview of renewable gas and opportunities to convert the network to 100% zero carbon gas by 2040. We provided examples of hydrogen projects and how hydrogen can be blended into the network and supplied to homes and businesses.
	• We discussed innovation for a range of purposes (e.g. metering, trialling new technologies, investing in sustainability).
	• Engagement Activity:
	  • Is it important to you that AGN supplies cleaner energy to customers? Why or why not?
	  • What areas of innovation do you think are important?
		✓ Clean energy and reducing carbon emissions is an imperative for the majority of customers.
		✓ 87% of customers view climate change and reducing carbon emissions as important or very important.
		✓ Many customers place importance and value on protecting the planet for future generations.
		✓ Customers expect AGN to be on the journey towards a cleaner energy supply.
		✓ Customers are keen to better understand the cost implications for transitioning to renewable gas, including the need to potentially switch appliances in the future.
		✓ Customers view innovation as an enabler to transition to cleaner energy and more affordable and safe gas supply.

	Phase 2 Customer Workshops	

	• We presented our proposed approach and low carbon strategy including network readiness and no regrets investments.
	• We presented current communications, marketing and education activities on renewable gas.
	• Engagement Activity:
	  • Are you comfortable with our proposed approach to preparing our networks for renewable gas? Do you need more information?
	  • Should AGN invest in a standard, medium or broad renewable gas communications campaign? Why? (3 options tested)
		✓ 89% of customers support AGN's proposed approach to preparing our networks for renewable gas.
		✓ Customers were keen for more detail around how customers would be kept updated and informed of the energy transition, particularly in relation to appliances and costs to bills.
		✓ 74% of customers supported increased investment ($2-3 per annum) beyond AGN's existing activities on more renewable gas communications and education activities.
		✓ 52% of customers supported a very broad communications campaign noting the importance of school and community education.

Table 5.5: Customer workshop summary feedback (cont.)

Theme	Engagement Activity	Key Insights and Results
	Phase 1 Customer Workshops	

	• We provided an overview of the residential and business customer billing process and the composition of residential/business gas bills.
	• Engagement Activity:
	  • Do you have any questions on price and how bills are set?
	  • What does affordability mean to you?
		✓ 36% of customers ranked price as their number one priority.
		✓ Customers have little understanding of the makeup of their gas bill and are keen for more education and transparency.
		✓ Customers told us affordability means fair and transparent prices, manageable prices and forward visibility to avoid 'bill shock'.
		✓ Gas affordability for all is a key customer sentiment, with specific emphasis on those experiencing hardship (financial and non-financial).
		✓ Some customers, particularly CALD, desire more information and education on gas safety.
		✓ Customers are looking for new digital ways to manage their gas usage and reduce their bills.

Provide affordable and accessible services 	**Phase 2 Customer Workshops**	

	• We presented on how we set prices and our forecast price reduction. We discussed how gas distribution prices are set in the context of a regulatory framework.
	• We presented on ways in which we could provide services for people experiencing vulnerability.
	• We presented options for digital metering.
	• We presented some examples of how we communicate with CALD customers.
	• Engagement Activity:
	  • Do you have any questions on our early forecast on prices?
	  • How important is it to you that we provide services to customers who might be vulnerable?
	  • What tools could we make available to better assist CALD customers.
	  • When you think about smart metering, what would you see the benefits (options provided)
		✓ Customers were interested in understanding how price reductions are passed through to end users.
		✓ 93% of customers thought it was either important or very important that we look at dedicated services for customers experiencing vulnerability, quoting the need for inclusivity and fairness.
		✓ Financial support, energy saving support and opportunities for tailoring customer service are supported by customers as ways to help those in need.
		✓ CALD customers noted the importance of translation services, empathetic and patient customer service and tailored communications.
		✓ Customers want to better understand and increase efficiency of their daily usage.

In Phase 1, customers told us that:

- ✓ Gas supply is an essential service used every day in the kitchen, cooking, hot water, heating in winter and therefore needs to be **reliable** with no interruptions

"My life will come to a standstill if the gas supply stops. We cook on gas tops at home and at my restaurant"

- ✓ **Public safety** means responding to leaks as quickly as possible, maintaining the network and proactive technology, safety campaigns for home appliances
- ✓ **Affordability** means keeping prices as low as possible, looking after those who are vulnerable.

"I would be comfortable paying a higher bill if I knew it would offset a more needy customer's bill"

- ✓ Good **customer service** includes prompt responses, easily identifiable meter readers, multiple methods for contact, speaking to a person
- ✓ A **cleaner energy** is important for the environment, future generations, it is the right thing to do – but cost is also important
- ✓ Areas of **innovation** include smart metering/apps to monitor usage and cost effective management of assets, sustainable practices

"I want to understand what my gas usage is … to alter my budgeting needs"

<u>Phase 2 Customer Workshops: Objectives, engagement activities, and results</u>

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

The objectives of our Phase 2 workshops were to:

- ✓ Validate customer feedback from Phase 1
- ✓ Share information about AGN's activities
- ✓ Explain how prices are set
- ✓ Explore issues of importance to AGN and customers
- ✓ Test and seek feedback on costed proposals

Phase 2 workshops were 2 hours in duration and included opportunities for open discussion with AGN subject matter experts and digital polling. Participants were invited to vote and rank initiatives /options that they were supportive of, using an online voting tool.

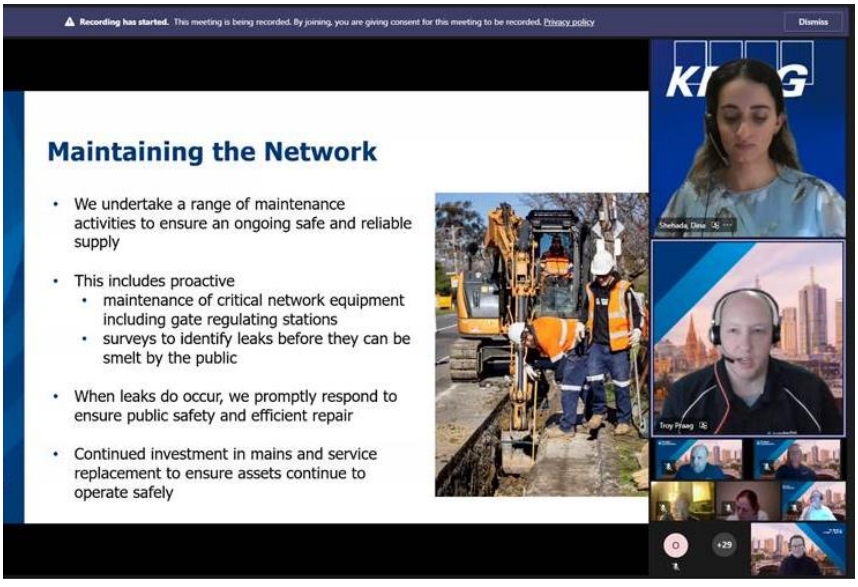
In Phase 2 we presented an early price forecast to reduce prices by an indicative 8%. In this context we presented our proposed approach for investment in reliability, safety, mains replacement and customer service. We explored areas for further development as identified by customers including digital customer service, preparing the network for renewable gas, renewable gas communication, supporting customers experiencing vulnerability, providing support in other languages and digital smart metering.

Key topics, information presented and insights from Phase 2 workshops are provided in Table 5.5. A full report on the Phase 2 Workshops and results is available on Gas Matters (gasmatters.agig.com.au).

In our Phase 2 workshops, we learned that:

- ✓ Cost remains a key driver of decisions making for some customers
- ✓ 9 out of 10 customers are comfortable with our proposed approach to maintain current levels of safety and reliability

Figure 5.4. Round two customer workshop presentation on MS Teams



- ✓ On communication, SMS remains a highly valued feature for many, particularly CALD and elderly customers
- ✓ Customers are interested in the future of gas, and this translates to a desire for more information
- ✓ A large proportion of customers support investment in renewable gas communications to educate and inform the community
- ✓ Ensuring that there is support for priority customers is accessible and fair is important to all customers
- ✓ Vulnerable and CALD customers have specific needs and require tailored support
- ✓ Customers want to better understand and improve efficiency of their daily usage

Engaging with large gas users

Feedback gathered at the outset of our engagement program highlighted the importance of engagement with large gas users through dedicated activities as they represent an important customer segment with unique needs.

To do this, we partnered with EUAA, Ai Group and Major Energy Users (MEU) and their members to deliver two forums in the lead up to the publication of this Draft Plan.

These forums focus on exploring the key issues facing major gas users when it comes to their gas supply over the 2023-28 period.

Specifically, gas major users have told us that:

- ✓ The price of gas represents a significant cost to them, and they would like to see AGN keep their prices down
- ✓ They expect high levels of customer service, through dedicated commercial and account managers
- ✓ They are concerned about the continuity of gas supply and would like to avoid gas curtailment
- ✓ They would like to understand our plans when it comes to the decarbonising the gas network and the potential implications for them
- ✓ They would like AGN to avoid stranded asset risk and continue to grow the network

The first two forums were held in June and October of 2021, with the third scheduled for early 2022.

We developed and distributed a survey to large gas users on our network, seeking their input into both the expected demand for natural gas with regards to their business and the services that we will provide over the five-year term of our business plan.

5.6.2 Stakeholder Roundtables, Meetings & Forums

Victorian Gas Network Stakeholder Roundtable

The VGNSR is made up of customers and other stakeholders advocates who represent a wide range of Victorian gas end-users, including customers in vulnerable circumstances, culturally and linguistically diverse customers, businesses of all sizes and industries, social service organisations, local government, property developers and appliance manufacturers.

Table 5.6: Victorian Gas Network Stakeholder Roundtable

Membership
• Australian Industry Group
• Australian Energy Council
• Brotherhood of St Laurence
• Council on the Ageing (COTA)
• Energy and Water Ombudsman (EWOV)
• Energy Users Association of Australia (EUAA)
• Major Energy Users (MEU)
• Ethnic Communities' Council of Victoria (ECCV)
• Ethnic Council of Shepparton and District
• Gas Appliance Manufacturers Association of Australia (GAMMA)
• Master Plumbers Association (MPA)
• Municipal Association of Victoria (MAV)
• Property Council of Australia
• Urban Development Institute of Australia (UDIA)
• Victorian Council of Social Service (VCOSS)

The role of the VGNSR is to:

- ✓ Provide input and feedback to inform the development of our plans, ensuring they are capable of acceptance by customers and stakeholders.
- ✓ Inform and shape our engagement activities to ensure we deliver best practice, fit for purpose engagement.
- ✓ Advocate in the interests of all constituents to ensure our plans deliver value for all customers.
- ✓ Challenge our business to deliver the best possible outcomes for current and future customers.

The VGNSR has had input into the design of all our engagement activities. We have also invited them to attend and observe any sessions of interest and presented back key insights at our meetings.

The VGNSR has met seven times between March and December 2021 in the development of our Draft Plan. We anticipate that we will meet with them a further two times as we refine our plans.

A summary of key topics and information presented is summarised in Table 5.7.

The VGNSR members were keen to understand our future plans in the context of price, and importantly that our proposals are cost efficient while delivering for current and future customers. As such, we provided early price modelling to members at our meeting in August (meeting #4). This early presentation of our price is consistent with our commitment to a no surprises approach to engagement.

Key challenges considered by VGNSR

While the VGNSR was established to engage directly on our plans for the 2023-28 regulatory period, there are broader challenges and themes that have been raised throughout our engagement with the group. These are summarised below.

- The **future of gas** and what options and responses might be considered by gas network businesses
- The **cost of renewable gas** and how the global market might impact that
- Ensuring that the **energy transition is cost effective** and in the interests of current and future customers
- **Intergenerational equity** and what pricing structures are being considered as part of the energy transition to safeguard current and future customers
- How networks might respond to **green developments** and the push for **electrification** in areas where aggressive 2030 decarbonisation targets have been set
- **Gas usage efficiency** and more efficient use of appliances
- Clarification around what it means to deliver a plan that is "**capable of acceptance**" and to whom this applies (i.e. the regulator, customers, or both)

Table 5.7: VGNSR Meetings

Meeting #	Key Topics	Summary of Information presented
Meeting #1 (March 2021)	• Developing our future plans • Stakeholder Roundtable • Our business • Draft Engagement Plan • Pipeline and Reference Services	• Proposed approach to developing future plans • Role of the Stakeholder Roundtable • Our networks • Draft Engagement Plan consultation • Pipeline and Reference Service overview
Meeting #2 (March 2021)	• Final Stakeholder Engagement Plan • Pipeline and Reference Services • Future of gas	• Feedback on our Draft Engagement Plan • Pipeline and Reference Services overview and update • Renewable gas projects, commitments and framework

Meeting #3
(May 2021)
	• Reference Services Proposals
	• Stakeholder engagement
		• Summary of feedback received on Pipeline and Reference service proposal
		• Engagement activity update:
		  • Major Users Forum
		  • Phase 1 Customer Workshops
		  • Future of gas engagement

Meeting #4 (August 2021)	• Future of gas expert panel • Early regulatory modelling • Stakeholder Engagement update	• Overview of early expenditure and price modelling • Future of gas co-design approach • Customer workshops update • Stakeholder engagement activity update
Customer Workshop and PSP Update (September 2021)	• Customer workshop results • Assisting customers experiencing vulnerability	• Our workshop methodology • Phase 1 findings and insights • Priority Service Program overview
Meeting #5 (October 2021)	• Early expenditure modelling • Incentive schemes • Stakeholder engagement update	• Early expenditure and price modelling update • Proposed approach to Incentive schemes • Future of gas co-design update • Stakeholder engagement activity update
Meeting #6 (November 2021)	• Customer workshops • Price modelling • Future of gas • Stakeholder engagement • AER presentation	• Recap of early price modelling • Round 2 customer workshops overview • Future of gas scenario modelling update • Stakeholder engagement activity update • AER presentation on information paper
Meeting #7 (December 2021)	• Draft Plan Overview • Expenditure • Future of Gas • Capital Base • Demand	• Early information on key parameters of proposals • Information detailing proposed opex and capex expenditure including step changes • Future of gas update and scenario modelling • Capital Base • Demand forecasts

Retailer Reference Group

The Retailer Reference Group (RRG) is a mechanism used to formally engage with gas retailers, who play a major role in customers experience with our gas networks.

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

Membership on the RRG includes AGL, Lumo/Red Energy, Alinta Energy, Energy Australia, Origin Energy, Simply Energy, Sumo Energy and 1st Energy.

The group has met seven times in the lead up to this Draft Plan. The table below provides a summary of key topics and information presented at RRG meetings.

Engagement with the Property Industry

With the support of the Urban Development Institute of Australia (UDIA), an advocacy group for the property development sector, we

Table 5.8: Retailer Reference Group Meetings

Meeting #	Key Topics	Summary of Information presented
Meeting #1 (March 2021)	• Developing our future plans • Our business • Stakeholder engagement program • Pipeline and Reference Services	• Proposed approach to developing our future plans • About our networks • Draft Engagement Plan for consultation • Pipeline and Reference services overview
Meeting #2 (March 2021)	• Stakeholder engagement • Pipeline and Reference Services	• Feedback on our Draft Stakeholder Engagement plan • Pipeline and Reference Services update
Meeting #3 (May 2021)	• Pipeline and Reference Services • Stakeholder engagement	• Pipeline and reference services Proposal overview • Stakeholder engagement plan update
Meeting #4 (August 2021)	• Early price modelling • Future of gas expert panel • Terms and conditions • Stakeholder engagement update	• Overview of early price modelling • Future of gas co-design approach • Terms and conditions overview • Stakeholder engagement activity update
Meeting #5 (October 2021)	• Early expenditure modelling • Incentive schemes • Terms and conditions	• Early expenditure and price modelling update • Proposed approach to Incentive schemes • Terms and conditions timeline update
Meeting #6 (November 2021)	• Terms and conditions • Future of Gas • Capital Base • Demand • Stakeholder engagement update	• Update on terms and conditions • Future of gas update expert panel and modelling update • Capital demand • Demand forecasts • Stakeholder engagement activity update
Meeting #7 (December 2021)	• Draft Plan Overview • Expenditure • Future of Gas • Capital Base • Demand	• Early information on key parameters of proposals • Information detailing proposed opex and capex expenditure including step changes • Future of gas update and scenario modelling • Capital Base • Demand forecasts

met with property developers in June 2021. A key focus for property developers is discussing our future plans for renewable gas developments, and what reaching net zero emissions by 2050 might look like for gas networks.

Engagement with Gas Plumbers

In collaboration with the Master Plumbers Association, we held an online forum with gas plumbers in June 2021. Gas plumbers are particularly interested in understanding our plans to safeguard the future of the gas networks, and any related government positions / policy. We will meet again with gas plumbers in early 2022, to seek their feedback on our Draft Plan.

5.6.3 Future of Gas Expert Panel

Based on our early engagement, we knew that the future of gas would be a major focus of our engagement program. We established a Future of Gas Expert Panel comprising of nine key stakeholders and experts from the energy sector in Victoria (see table 5.9 for details on Panel members).

The scope of the Expert Panel was to:

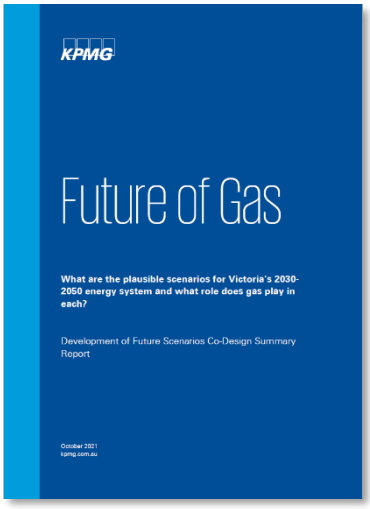
- Co-design four plausible scenarios for the future energy system (2030 – 2050), and the role of gas in each scenario
- Produce a qualitative description of the drivers for each scenario
- Ensure the output produced represented four plausible scenarios rather than predications or preferences for the future.

The Expert Panel was formed to leverage the skills and knowledge of each of the panel members.

Table 5.9: Future of Gas Expert Panel

Membership	Expertise
Anna Freeman, Director, Energy Generation Clean Energy Council	Anna is the Policy Director of Energy Generation and Hydrogen at the Clean Energy Council, and a member of the NSW Energy Sector Board.
Alison Reeve Deputy Program Director, Energy Fellow Grattan Institute	Alison is the Climate Change and Energy Deputy Program Director at the Grattan Institute and has two decades of experience in climate change, clean energy policy, and technology
Lynne Gallagher Chief Executive Officer, Energy Consumers Australia	Lynne is an Economist/Econometrician by qualification and has substantial experience in policy reform processes, including working with the Council of Australian Governments.
Matt Clemow Group Manager Gas Operations, AEMO	Matt is responsible for AEMO's gas operations in eastern Australia, including Victorian gas transmission, the wholesale gas markets, and gas supply adequacy for power generation.
Mark Grenning Director, Energy Users Association Australia	Mark has been a long-term Director and past Chairman of the EUAA.
Dr Patrick Hartley Leader of CSIRO Hydrogen Industry Mission	Dr. Patrick Hartley is the leader of CSIRO's Hydrogen Industry Mission.
** Membership also included AGIG CEO Ben Wilson (to Oct 2021), Craig de Laine AGIG CEO (from Nov 2021) and Jon D'Sylva EGM Strategy & Regulation at AusNet	

Panel members from diverse backgrounds were selected to ensure that the discussions on all scenarios considered the relevant political, economic, social, technological, environmental and legal drivers.



We undertook four, three hour co-design workshops with the Expert Panel. For each scenario the panel explored key industry trends and drivers, developing high-level narratives, outlined assumptions and enablers and graded the potential economic outcomes.

We asked members to complete a short online feedback survey at the end of co-deign process. All panel members agreed that the insights they shared were heard and reflected throughout the process, and the outcomes of the scenario development phase were achieved.

> ***"A well facilitated process which made the most of the time we had together. Certainly a good approach to get the stakeholders to co-design the scenarios". Expert Panel Member October 2021***

More detail about the co-design methodology undertaken with the Expert Panel can be found at gasmatters.agig.com.au.

5.6.4 Priority Services Panel

AGN is in the early stages of implementing a Priority Services Program (PSP) in South Australia, designed to better support customers on that network experiencing vulnerability. We were keen to explore a similar program with our Victorian customers but wanted to ensure that it was fit-for-purpose for Victorians who might need a little more support and care.

We know that affordability and helping those in need is important to our customers and stakeholders. In fact, 93% of customers in our customer workshops said that providing dedicated services to vulnerable customers was important or very important.

To design a program that supports the needs of priority service customers, we established a PSP Advisory Panel comprising of key representatives from social services organisations with a national and/or Victorian focus. Table 5.10 provides a summary of members on the Panel.

Table 5.10: Priority Services Panel Advisory Group

Membership
• Brotherhood of St Laurence
• Ethnic Communities Council of Victoria (ECCV)
• Financial Counselling Victoria
• Safe Steps
• Energy and Water Ombudsman (EWOV)
• Uniting Vic Tas
• Council on the Ageing (COTA)
• Victorian Council of Social Service (VCOSS)
• Consumer Action Law Centre
• St Vincent de Paul

In September and December 2021, we held the first two workshops with the Advisory Group. These workshops were designed to explore the role of gas network businesses in supporting priority customers, possible initiatives we could implement and how these should be prioritised. We will hold a third, and final, workshop with the Group in early 2022 to further refine our proposed program. The focus of each of the workshops is described below.

You can read more about our proposed PSP in Chapter 8.

5.6.5 Gas Network Innovation Scheme

Over a period of more than 12-months (September 2020 to October 2021) a sector-wide engagement program to explore innovation in the gas networks was undertaken. This sector-wide approach involved MGN, AusNet and Jemena Gas Networks (in New South Wales). Across two key phases, the aim was to understand levels of support for the development of a customer-funded gas innovation scheme and if there was majority support, to co-design a potential network innovation scheme with stakeholders.

We established a stakeholder reference group who was responsible for providing ongoing advice and feedback on the design and delivery of the GNIS engagement program.

The engagement was supported by KPMG as the independent engagement partner and a stakeholder reference group which provided ongoing advice and feedback on the design and delivery of the GNIS engagement program. Reference group membership included ATCO, Evoenergy, the AER, Energy Networks Australia, Energy Consumers Australia and APA.

More information on our GNIS engagement, including engagement materials and reports can be found at gasmatters.agig.com.au.

5.7 Summary Feedback

We have undertaken a range of engagement activities to support the development of this Draft Plan.

All customer feedback and how we have responded in this Draft Plan is shown in Table 5.11.

Table 5.11. Customer and Stakeholder feedback and our response

Topic	Customer and stakeholder feedback	Our response
Pipeline & reference services	• Stakeholders and Retailers were keen to see AGN, MGN and AusNet align their pipeline and reference services where practically possible. This was particularly important for Retailers who would like to be able to compare these services across each business. • Stakeholders asked for a comparison table of charges, both network and retailer, across each identified service • Retailers were keen to see AGN remove reference services with low use.	• We circulated a draft Pipeline and References Services Proposal (RSP) to VGNSR and RRG members on 30 April 2021 for consultation. • On 1 July 2021 we submitted our RSP to the AER. • The AER approved the RSP in November 2021.
Price & affordability	• 36% of customers ranked price as their number one priority. Although price is a top priority, customers are adamant lower prices should not compromise safety or reliability. • Customers told us affordability means fair and transparent prices, manageable prices and forward visibility to avoid 'bill shock'. • Customers were keen to understand how gas distribution prices are included in their final bill – and how any savings might be passed on from their retailer. • Gas affordability for all is a key customer sentiment, with specific emphases on those experiencing hardship. • 74% of customers supported increased investment ($2-3 per annum) beyond AGN's existing activities on more renewable gas communications and education activities. • Gas is a significant cost for many major gas users (commercial and industrial customers) and they stressed the importance of keeping costs low. • Stakeholders supported AGN's proposal to consider opportunities to better support customers experiencing vulnerability for inclusion in this Draft Plan.	• We have had regard for the price impact of individual decisions as we developed the Draft Plan. • This Draft Plan proposes reducing prices for customers by 8% (after inflation) the first year of the next period, followed by increases consistent with inflation in subsequent years. We will engage on the price path with customers in the lead up to the Final Plan. • We will engage with Retailers to encourage that they pass on of any savings to customers when our new prices take effect on 1 July 2023. • We are considering investing in a Priority Services Program to deliver service improvements for customers who are experiencing vulnerability on our network. We will further test and explore this in our Draft Plan consultation.

Table 5.11. Customer and Stakeholder feedback and our response

Topic	Customer and stakeholder feedback	Our response
Customer Service	• Stakeholders and customers have provided positive feedback on our current performance in terms of customer service, in particular that AGN tracks and sets targets for customer satisfaction levels. • When customers interact with AGN they expect responsive and effective resolution. • When communicating with AGN, customers expect professionalism, respect, simple and clear language, empathy and patience. • Customers prefer phone for priority services like a gas leak, whereas digital communications (SMS) and preferred for updates on outages and new connections. • SMS for communications and customer service appeals to many customers for convenience and the ability to receive instant notifications. • SMS is a high valued communication tool by CALD customers and senior Australians. • 57% of customers support investment in SMS technology for communications at $2.50 pa bill impact. The remaining 43% supported website and email questioning costs given low frequency of interactions. • Many customers are satisfied with current meter reading practices, with some customers interested in smart meters and access to real-time data on gas usage. • Major gas users (commercial and industrial customers) expect high levels of customer service from AGN via dedicated commercial and account managers.	• We are proposing to maintain investment in customer service and achieve 8.4 out of 10 or above in our customer satisfaction survey. • Our opex proposal will ensure continued improvement in customer service experience in terms of inclusivity and accessibility of communications and new investment in a priority services program for customers experiencing vulnerability. • Our capex proposal includes investment to improve online services via digital channels in response to feedback from customers. • We have also proposed to replace around 3,600 hard to read meters with new meters that are read remotely and undertake a trial of digital meters in Albury/Wodonga as a first step for digital metering. This will reduce estimated reads which we know are a particular pain point for our customers and will provide us with more information that may support the wider roll out of digital metering options across our network. • We will continue to provide quality customer service to our major gas users through the employment of dedicated account managers.

Table 5.11. Customer and Stakeholder feedback and our response

Topic	Customer and stakeholder feedback	Our response
Our capital and operating expenditure proposals	• Customers value their current gas supply and expect levels of public safety and reliability to be maintained. • Customers consider gas as an essential service, especially for heating in the colder months in Victoria. • After price, reliability and safety are the top two priorities for customer. Although price is a top priority, customers are adamant lower prices should not compromise safety or reliability. • Customers view safety as a non-negotiable. • 95% of customers are satisfied with the reliability of their gas supply. • 88% of customers supported AGN's proposed approach to maintain current safety and reliability performance, with 11% of customers asking for more information to be able to make a decision. • Stakeholders raised questions about our mains renewal program expenditure, and whether this is prudent given uncertainty around the future of these assets and the potential for more stranded assets and larger write downs. • Stakeholders and Retailers raised a question around whether it is prudent to continue to invest in growing the network by connecting new customers and network augmentation while simultaneously proposing accelerated depreciation, when the two activities seem at odds.	• Our totex forecast (combined opex and capex) for the next AA period are consistent with the levels we expect to incur in the current AA period. • The level of totex enables us to maintain safety, reliability and the service levels expected from our customers. • Our opex forecast is discussed in Chapter 8 of this Draft Plan, and has been developed applying standard regulatory methodologies. • Our capex forecast is discussed in Chapter 9 of this Draft Plan. While we are proposing lower investment compared to current levels on the back of completing our low pressure mains replacement program, our proposal will deliver the high levels of public safety and reliability valued by our customers and in line with our safety obligations, grow our network (ultimately leading to lower prices for all of our customers), assist the transition of our network to support the delivery of renewable gases over the next decade and ensure we continue to provide customer service that meets the expectations of our customers today.
Capital Base	• Stakeholders acknowledged complexities around the future of the network given the ongoing decarbonisation of energy supply, particularly how this could affect the economic life of gas assets/networks and therefore the need to accelerate depreciation. • Stakeholders queried if Victorian network businesses were proposing accelerated depreciation on the entire asset base or just certain types of assets. • Stakeholders asked about pricing access to new developments and whether these are considered when networks undertake expansion work for the next regulatory period. • Stakeholders and Retailers acknowledged that it might make sense for networks to propose	• As discussed in the Future of Gas (Chapter 6), this Draft Plan proposes the acceleration of depreciation given the uncertainty for gas networks in a decarbonised future energy supply. • Taking these steps today will mitigate risk and enable stable pricing into the future, thereby supporting the transition of the network to renewable gases. • As outlined in Chapter 10 of our Draft Plan we have however continued to apply the asset lives that were approved by the AER for the current AA period.

Table 5.11. Customer and Stakeholder feedback and our response

Topic	Customer and stakeholder feedback	Our response
	more accelerated depreciation now (in the near-term being smaller price cuts / bigger price rises), from an intergenerational equity standpoint.	
Rate of return	• Stakeholders acknowledged our intention to adopt the AER's Rate of Return Instrument and the AER's approach to determining the tax allowance.	• We have applied the AER's current Rate of Return Instrument, as described in Chapter 11 of this Draft Plan. • We have applied the outcome of the AER's Tax Review.
Demand forecast	• Stakeholders noted the complexities faced by AGN when forecasting demand. They noted that macro-trends such as population change, new housing growth and regulatory codes need to be considered. • Stakeholders were interested in more details around expected connection growth on our network in the coming regulatory period. • Stakeholders were interested in understanding the impact of any ban on new connections, if one were to be imposed, and how AGN might respond to that. • Stakeholders wanted to understand the current rate that customers are choosing to disconnect from the network.	• As outlined in Chapter 13 of this Draft Plan, our demand forecast applies methodologies accepted by the AER for our most recent South Australian and Victorian reviews. • The forecasts are based on our historic trends but also consider current state and federal energy policy, future projections of dwelling growth, energy prices and the impact of weather.
Incentives	• Overall, Stakeholders support the idea of a Gas Network Innovation Allowance. The support was stronger among consumers and their representatives, compared to Retailers (who did not support it). • Stakeholders are keen to see appropriate checks and balances are in place to safeguard customers.	• We consider incentive mechanisms to be an important part of a regulatory framework that help deliver efficiencies to customers in a timely manner. Incentive schemes proposed are outlined in Chapter 12 of this Draft Plan. • We are proposing the continuation of the opex and capex incentive mechanisms for the next AA period, with the contingent CESS updated to reflect the more recent AER decisions for Jemena in NSW and AGN in SA. • We are proposing a Gas Network Innovation Scheme which we have co-designed with customers, stakeholders and the other gas distribution businesses. We are seeking further feedback on the level of funding and types of projects that should be allowed under the GNIS for the next AA period.
Future of Gas	• Clean energy and reducing carbon emissions is an imperative for the majority of customers.	• We are taking steps to support the long-term future of the network in line with the decarbonisation goals of Victoria and Australia's energy sector, as well as our own plans, such as:

Table 5.11. Customer and Stakeholder feedback and our response

Topic	Customer and stakeholder feedback	Our response
	• 87% of customers view climate change and reducing carbon emissions as important or very important. • Many customers place importance and value on protecting the planet for future generations. • Customers expect AGN to be on the journey towards a cleaner energy supply. • Customers are keen to better understand the cost implications for transitioning to renewable gas, including the need to switch appliances. • Customers view innovation as an enable to transition to cleaner energy and more affordable and safe gas supply. • 89% of customers support AGN's proposed approach to preparing our networks for renewable gas. • Customers were keen for more detail around how customers would be kept updated and informed ongoing in the energy transition, particularly in relation to appliances and costs to bills. • 74% of customers supported increased investment ($2-3 per annum) beyond AGN's existing activities on more renewable gas communications and education activities. • 52% of customers supported a very broad communications campaign noting the importance of school and community education. • Stakeholders and Retailers stressed that through renewable gas communications AGN should not guide customers to choose one gas pathway over another, and the need to align messaging with potential future policy decisions. • Stakeholders acknowledge the complexities facing network business when it comes to the future of gas and agree that is important that networks keep their options open. • Stakeholders wanted to see our engagement on the future of gas tie in with other processes and projects exploring the same issue. • The cost of renewable gas and associated intergenerational equity issues were raised as	• Keeping options open by accelerating $144 million of depreciation which will support the long-term competitiveness of the network to provide energy choice for customers and stable prices in a net zero carbon future; • Continuing to connect new customers to ensure the viability of the transition of the network to renewable gases; • Investing $25 million in no regrets actions to ensure the network is ready for the distribution of hydrogen which includes updating procedures, replacement of incompatible parts, further compatibility studies and a digital ultrasonic residential meter trial in the Albury/Wodonga region; • Introducing a new Gas Network Innovation Scheme, which will provide $5 - 7.5 million in funding over the period that can be used to deliver innovative projects that are likely to deliver customer benefits, with any unspent funds passed back to customers; and • Undertaking a renewable gas communications and education program ($7 million) which will help customers to feel confident today that renewable gas will be available in the future.

Table 5.11. Customer and Stakeholder feedback and our response

Topic	Customer and stakeholder feedback	Our response
	a key concern among Stakeholders and Retailers when considering solutions for the future. • Stakeholders stressed the need to bring customers along the gas decarbonisation journey with them with effective communication techniques. AGN was encouraged by stakeholders to do more in this space. • Major gas users (commercial and industrial customers) stressed the importance of gas for industrial processes and were keen to understand our plans to safeguard this supply into the future, particularly when considering policy uncertainty.	

5.8 Next Steps

Consultation on this Draft Plan is open for 2 months.

A range of engagement activities are supporting the consultation period including a further phase of customer workshops, and continued engagement with VGNSR and RRG. We will also be holding dedicated deep dive sessions on key aspects of this Draft Plan with interested stakeholders.

A series of consultation questions are included in this Draft Plan. Submissions can be made online at Gas Matters (gasmatters.agig.com.au)

Gas Matters – our online engagement platform

All customer and stakeholder engagement resources relating to this Draft Plan are publicly available on our online engagement platform Gas Matters at gasmatters.agig.com.au

Resources include: -

- ✓ Engaging Victorians on the Future of our Networks (July 2023 to June 2028) – Draft Engagement Plan for Consultation
- ✓ Engaging Victorians on the Future of our Networks (July 2023 to June 2028) – Final Engagement Plan
- ✓ Customer workshop presentation materials and insights reports
- ✓ Major User Forum presentation materials
- ✓ VGNSR meeting presentation materials and minutes
- ✓ RRG meeting presentation materials
- ✓ Future of Gas Expert Panel KPMG report
- ✓ Priority Services Program Advisory panel workshop materials
- ✓ Gas Network Innovation Scheme insights reports

Consultation questions

Customer and stakeholder engagement	1. Do you have any feedback on our customer and stakeholder engagement program? 2. Have we considered customer and stakeholder feedback and responded appropriately in this Draft Plan?
Future of gas	3. Do you support the no regrets actions we have proposed? 4. Do you consider the accelerated depreciation approach we have proposed to be a reasonable response to the uncertainty we face? 5. Are there any other factors or information you think we should be considering in regard to the future of gas and the energy transition more broadly?
Pipeline and reference services	6. Do you think the pipeline and reference services we have proposed are appropriate?
Operating expenditure	7. Do you support our approach to forecasting operating expenditure? Is there sufficient information to understand our proposals and the basis of the costs included? 8. Do you support investment in a priority services program? Do you have any feedback on the activities we have proposed? 9. Do you support investment in a renewable gas communications and education program? Do you have any feedback on the activities we have proposed?
Capital expenditure	10. Do you support our approach to forecasting capital expenditure? 11. Is there sufficient information to understand our proposals and the basis of the costs included in our capex forecast? Is there any other specific information that would assist in the assessment of our proposal?
Capital base	12. Do you have any comments on our proposed approach to adjust our capital base over the current and next AA periods, including how we have taken into account the future of gas?
Financing costs	13. Do you have any comments on our approach to setting the financing and tax costs in this Draft Plan?

Incentives	14. Do you support our proposal to maintain the opex efficiency benefit sharing scheme EBSS? 15. Do you support our proposed changes to the contingent capital expenditure efficiency scheme (CESS) to align it with the schemes recently implemented in NSW and SA? 16. Do you support our proposed introduction of a Gas Network Innovation Scheme (GNIS) which we have co-designed with customers, stakeholders and other network businesses? 17. Do you have any feedback on the level of funding that should be allowed under the GNIS; for example $1 per year (or around $4 million over the period)? 18. Do you have any feedback on what types of projects should be in scope of the GNIS?
Demand	19. Do you support our approach to forecasting demand? 20. Do you have any feedback on how we have had regard to energy policy changes, Victoria's net zero by 2050 target and other factors that will affect demand over the next AA period?
Revenue and prices	21. Do you support our intended approach to aligning revenue with underlying costs in setting our proposed price path? Would you prefer an alternate price path, and if so, on what basis?
Network access	22. Do you support standardising terms and conditions across our AGN and MGN networks (including in other jurisdictions)?
Other	23. Is there anything else that our Draft Plan hasn't considered that is important to you? 24. Do you have any further comments or feedback on our Draft Plan?

6 Future of gas

The future of gas networks in a decarbonised energy environment is uncertain. Our networks are capable of transporting renewable gas, however it will take time for renewable gas to become commercially competitive. There are steps we can take today that will provide us the best opportunity to continue to provide customers with a choice in energy supply as we transition to the decarbonised energy future.

IN THIS CHAPTER:

- **We have co-designed four plausible Future of Gas scenarios with an expert panel to inform our proposal for the next AA period.**
- **Applying this framework is not about choosing a "correct" or most likely future scenario, but about developing approaches which are robust across scenarios and therefore keeping decarbonisation pathways open.**
- **We are proposing additional depreciation reflecting future uncertainty and competitive pressures posed by rapid technological change, and the Government policy risks our network may face over the next AA period.**

The energy sector is rapidly changing

Since the beginning of the current AA period, there has been significant change in the energy sector. There are three main drivers that impact the future of gas:

- Government policies and customer sentiment towards gas as we target a decarbonised future;
- Technological change which impacts both how energy is produced and the appliances which use energy; and
- The actions of electricity networks, largely in response to technological change as it affects them.

6.1 Government Policy – a framework for emissions reduction

Global, national and state-level commitments are driving policy action to reduce emissions and lower reliance on fossil fuels. At the same time, technological change in the renewable electricity sector is driving lower electricity prices and changing the competitive nature of the energy sector as a whole. As a result, governments, businesses and

customers are shifting to cleaner forms of energy.

For our networks in Victoria, emissions reductions targets at both the Commonwealth and State levels provide important context – both are targeting net-zero emissions by 2050. Victoria also has interim emission reduction targets - 28–33% by 2025 and by 45–50% for 2030 below 2005 levels.

In achieving Victoria's emissions reduction targets the State is looking to cut emissions across the entire economy – including the energy sector. For electricity, Victoria is accelerating the transition by ensuring that 50% of Victoria's electricity will come from renewable sources by 2030.

We are also seeing local governments take actions to decarbonise with some considering all-electric (renewable) solutions for developments in their jurisdictions.

For the gas sector, the Victorian Government is developing a *Gas Substitution Roadmap* (the Roadmap), which aims to "accelerate the development and deployment of all opportunities to decarbonise gas supply".[4] Through the Roadmap, the Victorian Government will outline actions for the displacement of natural gas in support of the emissions reduction targets in 2025, 2030 and the forthcoming 2035 target including hydrogen and biogas (see Box 1).[5] The Roadmap is expected during the first half of 2022.

6.2 Technological changes are impacting how energy is produced and the appliances which use energy

The rise of renewable electricity, particularly at the household level, affects both gas and electricity networks. There has also been significant technological growth and change at the appliance level. For example, improvements in air-conditioning efficiency and the introduction of electric heat-pumps. These developments may lead to changes in the cost advantage gas has traditionally had in home heating and cooking.

6.3 Electricity networks are responding to technological change

Electricity and gas prices both have a fixed and variable component. Almost all of our gas customers also consume electricity. If customers make a decision to switch from gas to electric appliances (for example, a gas hot water system to an electric heat pump), along with the cost of conversion, it is the variable charge for electricity that influences that decision, not the total fixed and variable charge (because the fixed charge for electricity will be incurred in either case).

Electricity networks are facing their own competitive challenges from rooftop solar. Solar delivers significant benefits to customers

Box 1: Renewable gases

Hydrogen

Hydrogen can be used much like natural gas to heat homes, power vehicles and produce electricity, but importantly when burned it produces only water vapour and energy as heat, with no carbon emissions. Blended with natural gas at volumes of 10% and potentially higher, hydrogen is likely to require no need for modification to existing appliances or the network. However, for 100% hydrogen, some modification to appliances will be required to account for the different characteristics of hydrogen and methane.

Hydrogen can be produced in a carbon free way by using a process called electrolysis, which uses renewable electricity to split water into hydrogen and oxygen.

Biomethane

Biomethane is the net zero emission gaseous fuel recovered from a wide range of renewable sources such as wastewater, food waste and landfill. Because the biomethane is recovered from other sources (preventing it from entering the atmosphere), it can be a source of net zero emissions. More importantly, biomethane can be produced to have much the same composition as natural gas today, meaning it can be injected into our networks with no modification to the network or user appliances.

[4] See: https://s3.ap-southeast-2.amazonaws.com/hdp.au.prod.app.vic-engage.files/1716/2544/4975/Victorias_Gas_Substitution_Roadmap_Consultation_Paper.pdf
[5] See: https://www.climatechange.vic.gov.au/victorian-government-action-on-climate-change/Energy-Sector-Pledge-Accessible.pdf

who install it, at the expense of those customers who do not. As electricity network charges are largely volumetric, but the costs are largely fixed (or sunk), customers who do not have rooftop solar bear more of the burden of costs.

There are several possible changes to the structure of electricity charges that networks could make to alleviate this issue. For example, increasing the fixed component of the network charge or introducing a specific charge for those customers with rooftop solar, to recover the costs borne by the network to support solar and other distributed generation. These sorts of changes to the structure of electricity pricing may result in lower variable electricity charges, making it harder for gas to compete. This is a key impact for gas network businesses, but also for all gas and electricity customers. Individual decisions made by customers comparing relative volumetric charges leading to disconnection from the gas network could lead to increased aggregate costs for the community, due to the significant electricity network augmentation required to accommodate the new load.

Box 2: Actions for the next AA period

Hydrogen ready capex

We are proposing to spend $21 million to ensure the network is ready for the distribution of hydrogen which includes updating procedures, replacement of incompatible parts, further compatibility studies and a digital meter trial in the Wodonga/Albury region (See Chapter 9).

Renewable gas communications

We are investing in a renewable gas communications package (based on average customer support levels of $2-3 per customer per year), as while 87 per cent of customers consider decarbonisation as important very few know about the decarbonisation plans for the gas networks (See Chapter 8).

Gas Network Innovation Scheme

We are proposing a gas network innovation scheme which will provide a clear framework (including rules and requirements) for funding innovative projects over the next AA period, including but not limited to renewable gas projects. More information is available in Chapter 12.

HyP Murray Valley

HyP Murray Valley will be integrated with the local network in Wodonga throughout the next AA period – delivering a 10% renewable hydrogen blend to around 40,000 customers in Wodonga and Albury. The aim is to demonstrate the technical viability and safety of this important technology (see Chapter 2).

6.4 Gas will continue to play an important part of Victoria's energy mix

As Victoria transitions to cleaner sources of energy, natural gas will continue to play an important part of Victoria's energy mix for years to come. In Victoria, households use more gas for cooking, space heating and hot water than anywhere else in Australia. Winter demand is approximately three times higher than summer, primarily due to heating. However, if we are to meet longer-term climate goals, natural gas will need to be replaced with a zero carbon alternative.

We are actively developing opportunities through hydrogen and biomethane projects. Gas distribution networks are capable of decarbonising residential and industrial heat through the use of renewable gases like hydrogen and biomethane. We are working closely with government, industry and amongst our stakeholders to make renewable gases a reality. Projects like HyP SA, HyP Murray Valley and the Australian Hydrogen Centre are laying a foundation for a zero emissions future (see Chapter 2). We are also proposing to undertake activities in the next AA period as part of the transition to renewable gas (see Box 2). We will continue to build on this foundation over the next decade as we transition to a zero carbon network. This will assist us in helping Victoria to decarbonise in the most efficient manner. Given the significant role that natural gas plays in the energy mix in Victoria (making up 22% of Victoria's total energy demand), decarbonising by way of full electrification to meet the ambitious policy targets set by Governments will prove more costly for customers in the long run, requiring very significant investment in electricity infrastructure to meet the increased demand.

6.4.1 Challenges of transition

Planning for transition, however, requires more than just considering hydrogen opportunities, and requires us to

carefully consider the kind of business we might be in the future and the market we will compete in. A key consideration will be the value our assets we can recover in decades to come as the energy sector evolves. In particular, based on the information currently available, it is likely that we would need to increase the speed of recovery of capital in most future circumstances because:

- if hydrogen is ultimately successful, we will transport it in a much more competitive energy marketplace, which would require prices lower than a regulatory building block model delivers without any changes to the current depreciation profiles. Current information suggests that if the speed of recovery currently provided for in the regulatory framework remains unchanged, by circa 2040, our competitors will be able to produce and deliver energy at a lower cost and gas networks will not be able to compete; and
- if hydrogen is not part of the future energy mix, we would need to recover our assets before full electrification occurs to avoid risks for our investors from asset stranding and significant price increases for our customers, who will not leave the network all at the same time.

Obviously, the second future circumstance involves a much greater increase in depreciation than the first. However, this Draft Plan proposes relatively small changes in depreciation, reflective of a balanced (in terms of our business continuity) view of the two scenarios. This is reflective both of our optimism about the future for our business and recognition of the importance of price stability to our customers wherever possible.

Price stability also informs our approach to depreciation in the modelling work we are undertaking. With the right plans for depreciation, we believe we can deliver stable prices for our customers through time (ie over multiple AA periods), even under future scenarios where hydrogen is not successful, provided we start early enough and make some changes now. However, if we make no change now, we know that under all scenarios (including where hydrogen succeeds) our customers will face increasing prices.

6.5 Planning for the future

As noted above, planning for our future involves considering both the physical aspects of the gases we transport (discussed in Chapter 9), and the type of market in which we are likely to operate. Both are equally important parts of our planning. We discuss in this section how we approach the market or "economic" component of our planning. The key risk we face is that some part of the capital we have invested to date, which is depreciated over very long time periods (up to 60 years), will remain unrecovered once competitive forces and the changing marketplace start to affect our pricing, and the market power we currently have and which forms the premise for the regulatory framework, no longer exists.

This is known as "economic asset stranding"; physical assets are still used, but the price of our services no longer reflects the unrecovered value of those assets, rather, only some portion of that unrecovered value. Economic asset stranding has negative impacts on asset owners and our customers. For us, the negative impact is obvious (an inability to recover investment in the network). For our customers, the risk arises because customers differ in their ability to leave the gas network, and those who leave last face higher and higher prices under the building block model embedded in the regulatory framework.

The key to dealing with economic asset stranding risk is to make relatively small changes early on, even in the face of future uncertainty. This is because doing so can result in smoother prices through time, and relatively small price impact for current customers. This has been recognised by the AER in its own recent Regulating Gas Pipelines Under Uncertainty paper (available here), which we have considered in preparing our approach (see below).

The information paper sets out a good summary of the risks faced by our industry and the ways in which regulators can and should respond to them. Amongst the tools available to networks and the AER, changing the profile of capital return by accelerating depreciation is the best approach. This is because it does not change the overall amount of capital recovery, only its timing.

The regulatory framework is set up such that depreciation schedules are supposed to be revisited from time to time as economic change occurs.[6] In support of this, the National Gas Objective requires consideration be given to both current and future customers.

[6] *See NGR 89(1)*

However, largely due to the stable environment which has prevailed for the first two decades of regulation, this has not happened for some time. Further, the factors forcing consideration of change in the next AA period are new.

Our Draft Plan has been formulated based on a substantial body of evidence and modelling, which will continue to be refined as we prepare our Final Plan. We have engaged with stakeholders to develop our approach. Our initial positions in this Draft Plan will form the basis for further consultation as we prepare our Final Plan.

We now describe our process in more detail.

6.5.1 Developing our accelerated depreciation proposal

In broad terms, our Draft Plan incorporates a framework which:

- assesses how much depreciation would need to be brought forward under four future scenarios in order to alleviate the economic asset stranding associated with each scenario; and
- brings that information together to inform an estimate of how much additional depreciation is required during the next AA period to provide a reasonable opportunity of earning back our efficiently invested capital, while supporting efficient prices for current and future customers.

Our process to date has had three stages:

- **Scenario development:** we brought together an expert panel from government, industry and consumer groups to come up with four scenarios which they think are feasible for our future. Applying this framework correctly is not about choosing a "correct" or most likely future scenario, but about developing approaches which are robust across scenarios.
- **Model development:** we engaged ACIL Allen to develop a consumer choice model which we use as our decision-making tool.
- **Model operation:** we run the model to derive outcomes for the different scenarios, and then use this information to formulate a final depreciation amount which we think balances risks between ourselves and customers appropriately.

The four scenarios are described in a report from KPMG, who facilitated our engagement with the expert panel.[7] The KPMG report describes the scenarios developed by the expert panel, what each scenario means for each of the drivers, and details how the expert panel reached their conclusions through a series of workshops.

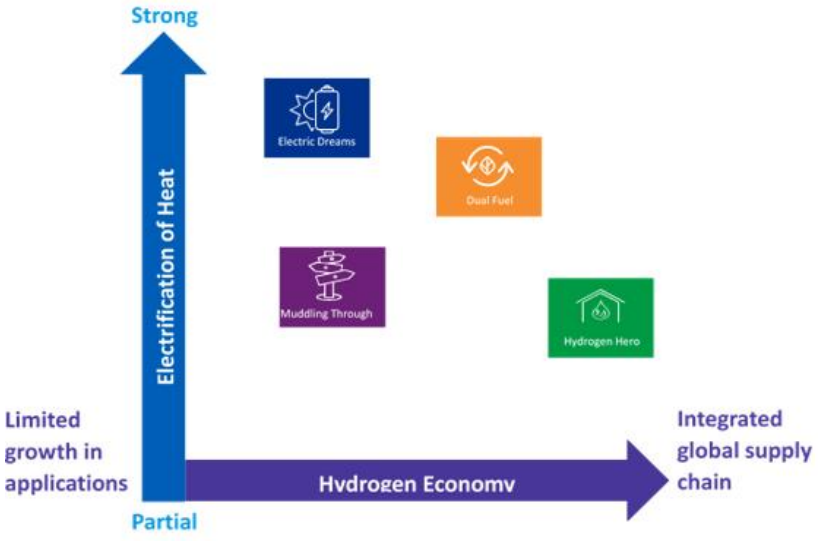
The scenarios themselves revolve around two "axes" describing the future, chosen by the experts as the most important aspects of how the future could play out. These aspects are the amount of electrification that occurs and the degree to which hydrogen succeeds as an energy carrier.

The four scenarios are shown in Figure 6.1.

For our business, the impacts of the four scenarios can be summarised as follows:

- **Electric Dreams:** Government follows a deliberate electrification policy involving new connection bans for gas and support for switching. There is limited or no support for hydrogen, which does not take off. Our networks are effectively out of business by 2050.
- **Dual Fuel:** Government supports both hydrogen and

Figure 6.1: Scenarios for the future of gas



[7] *See:* https://gasmatters.agig.com.au/66513/widgets/357049/documents/219128

electrification using a "horses for courses" approach whereby it supports a particular fuel for the use where it is likely to be most economical. Hydrogen does develop, including for export, but its use amongst our customers is limited to industrial customers and areas of our network which are close to industrial areas and can thus be served from the overflow of cheap hydrogen supply. Elsewhere, residential and commercial customers shift to electrification of their energy needs, as policy support has made this cheaper.

- **Muddling Through:** There is no particular policy direction supporting either hydrogen or electrification. We are able to move to a 10 percent hydrogen blend by 2030 due to our own efforts but cannot move any further. This blended gas competes with electricity in a market with no clear policy direction which might serve to lower risks associated with long term investment and both energy sources have higher costs than might otherwise be the case. It is not clear whether net zero by 2050 targets will be met.
- **Hydrogen Hero:** Strong government support is provided for hydrogen, which is essentially able to hold its own against the electrification of domestic energy. This is the closest to a business-as-usual scenario, with a different gas. It also requires the most investment on our part to meet the shift to a 100 percent hydrogen market, though most of this investment happens in subsequent AA periods.

The scenarios as described by the Expert Panel do not provide detailed quantitative information such as the price of hydrogen in 2040. Instead, they provide broad direction such as whether the relevant driver (things like gas prices, electricity prices and appliance prices) is high, medium, or low. In our modelling we therefore relied upon third party, reputable sources of information for things like fuel price paths and chose the quantitative information from scenarios which most closely match each of those above.

For the most part, we rely on information from AEMO's 2021 Inputs, Assumptions and Scenarios Report[8] as its scenarios were broadly comparable to those the Expert Panel developed. Our operating and capital costs are also different from one scenario to the next, and these have been sourced from internal engineering advice, which we aim to confirm with independent analysis in our Final Plan. We will update all inputs again before our Final Plan as new information becomes available.

Full documentation of the model, including a "User's Guide", will be provided with our Final Plan. We have already provided the AER with an early version of the model, and we have also provided information on several of the inputs to other stakeholders on request. We will continue with a high level of transparency and engagement going forward, including some "deep dives" with interested stakeholders in March 2022.

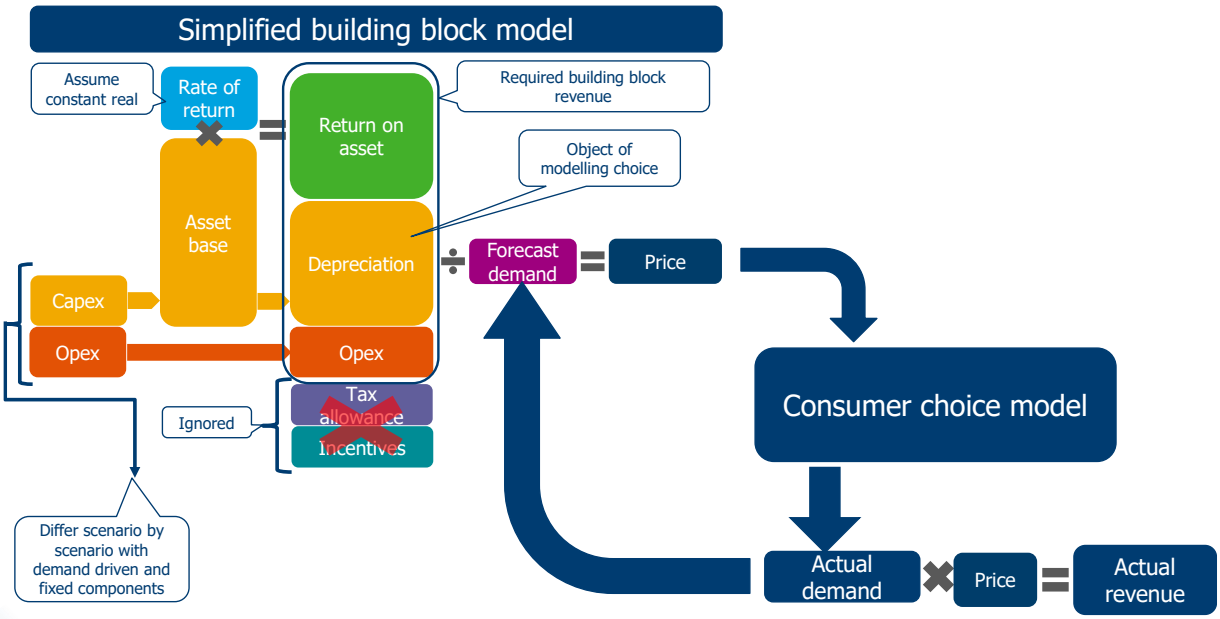
The structure of the economic model is shown in Figure 6.2, and it consists of two parts; a simplified building block model like the one the AER uses to set our regulatory prices and a consumer choice model which aims to proxy how future customers would react to those prices.

[8] See: https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-assumptions-and-scenarios-report.pdf?la=en..

In each scenario, we use the simple building block model to produce a price by dividing our costs (or "required revenues") by a forecast of demand. That price is applied in the consumer choice model which generates an "actual" demand for that future period. That demand is then used by the building block model to determine the price for the subsequent AA period. This is an iterative process between the building block and consumer choice models as the arrows in the figure below indicate. We then compare the revenue projected by the consumer choice model (price times demand for each year) with our costs in the building block model. If they are not the same, we amend the depreciation profile in the building block model until they equate, bringing forward the recovery of invested capital (but recovering no more capital overall). This works because there are fewer competitive pressures now than in the future, meaning shifting costs between future and current periods has less price impact on customers through time.

The net result of this process is a set of additional depreciation requirements during the next AA period.[9] It is important to note the outcome of the modelling presented below is preliminary and will be further refined as we work towards the Final Plan to be submitted to the AER on 1 July 2022. We will continue to engage with stakeholders and the AER as we progress the modelling over the coming months.

Figure 6.2: Simple model schematic

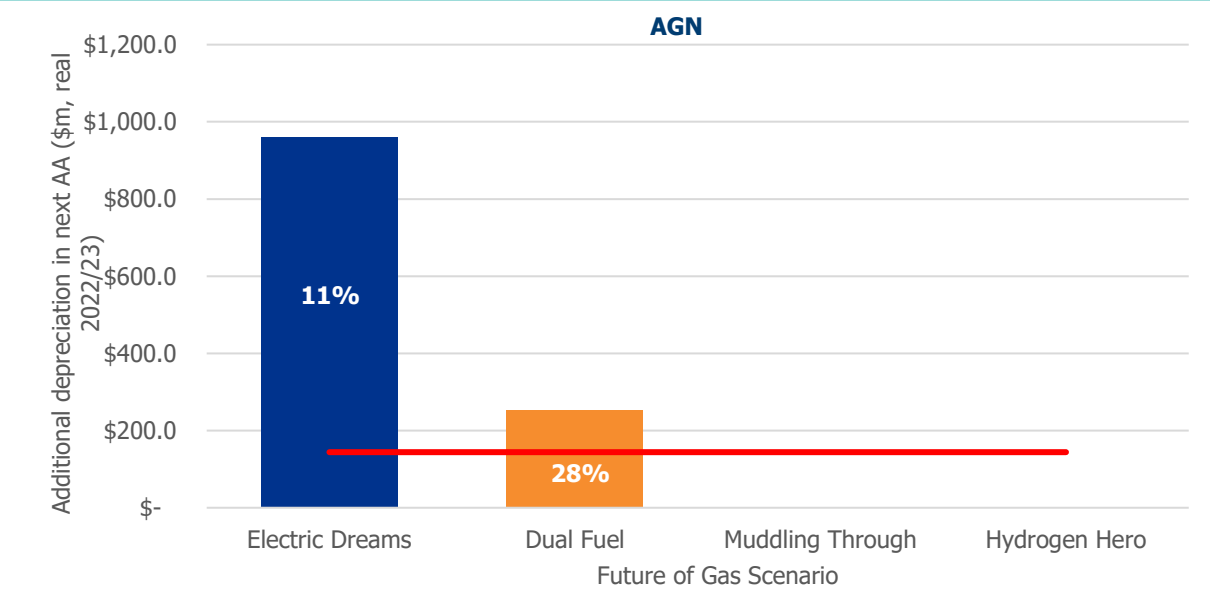


[9] We show just one set of results here. We have undertaken sensitivity analysis around these results and will continue to do so as we develop this work post-Draft Plan – the variable electricity price being a key focus. For now, our work provides us with confidence that the amount of extra depreciation we want to claim is very small compared to the risks we face.

Preliminary modelling for our AGN network

The preliminary modelling suggests that the Electric Dream scenario would require almost a billion dollars of additional depreciation over the next AA period, but this would only have a relatively small impact on economic asset stranding (reducing it by only 11% - the figure in the blue bar). For the Dual Fuel scenario, the increase would be in the order of $200 million, again without fully alleviating the economic asset stranding. The Muddling Through and Hydrogen Hero scenarios require no additional depreciation.*

Figure 6.3: Initial additional depreciation results



The modelling shows a great deal of variability in results at this early stage. Relying solely on the models produces two extreme results;

significantly increase depreciation (and prices) to try and alleviate the worst-case scenario (cognisant that this might only have a small effect); or

do nothing and hope the most optimistic scenario eventuates.

The former is unlikely to be acceptable given its pricing consequences, and the latter is overly risky and not in the long-term interests of our customers.

Given the uncertainty in the initial modelling undertaken to date, we have formulated what we believe to be a reasonable approach for this Draft Plan and a balancing of risk. This is represented by the red line which is the amount of depreciation ($144 million) which leads to price stability for our customers and only a small decrease in the risk we face. This amount of depreciation leads to a 22% (rather than 28%) reduction in asset stranding risk for the Dual Fuel scenario and a 2% reduction for Electric Dreams.

We note there are other options we could choose, which can change our risk profile. For example, a small price increase associated with more depreciation, in the scenario shown in Figure 6.3 above, could achieve almost all of the risk reduction of the "optimal" model results shown. Other approaches, such as shortening the lives of new assets (to a maximum of 30 years) could improve the risk outcomes with only a relatively small price effect.

These are issues we want to consult with customers on between now and the Final Plan to understand customers' views on the risk burdens, the appetite for price change now and the impact that might have on the sharing of risk between customers through time. We are also working on our model with the AER to make sure it reflects the best possible view of the future based on the information currently available. We will continue to review and change depreciation approaches in future AA periods as more information becomes available. The speed of recovery of our investment can be reviewed as the energy sector evolves.

** Sensitivity analysis around the results in Figure 6.3 shows that, with even slightly smaller electricity prices, this total would increase (as it does for the other scenarios). This highlights the importance of our approach of working with the AER and other stakeholders between the draft and final plans to refine all of the inputs and provide the best forecasts for the Final Plan.*

6.6 AER Information Paper – regulating gas pipelines under uncertainty

As noted above, the AER has recently released an Information Paper which summarises its views of the future risks to the gas industry and the options available to address these risks. The paper is available here, and we recommend it to interested stakeholders seeking to further understand the issues we have covered above. Other regulators have also begun to look at this issue, most notably the ERA in its recent decision for our Dampier to Bunbury Pipeline Decision (available here). In that decision, the ERA accepted our accelerated depreciation arguments for the DBNGP given the current uncertainty and likely decline in usage of the pipeline arising from technological and policy change.

The AER explores eight options for dealing with risk, ultimately expressing a preliminary view that depreciation is the best tool to use. This has informed our approach outlined above. The AER also discusses the need for thinking flexibly about depreciation, including changes in asset lives for new assets to try and balance the risk. This flexibility is something we plan on building into future discussions with the AER and stakeholders as we develop our approach towards the Final Plan.

The AER Information Paper makes clear that the burden of proof is on networks to provide strong evidence to support a case for a change designed to deal with future economic asset stranding risk. The AER is willing to act under conditions of uncertainty (understanding the improved outcomes for customers associated with acting early), but requires the best evidence currently available. In particular, the AER indicates that it would expect to see evidence to justify:

- the factors that influence the estimates of expected economic lives, such as applicable government policies, evidence of their customers' sentiments in switching away from gas, developments in competing technology etc (informs our consumer choice model discussed above, and informed by the Expert Panel);
- those assets that may be repurposed for transporting hydrogen and those that cannot be (considered as part of our capex plan and informs the consumer choice model discussed above);
- those assets whose economic lives may need to be adjusted to reflect the potential decline in long-term demand (part of extensions to the modelling done to date which we will be discussing with the AER to improve the flexibility of our depreciation approach);
- the value of stranded assets under the different forecasting scenarios (discussed above in the modelling results);
- the costs that may be avoided or incurred in the different forecasting scenarios (forms part of the consumer choice modelling inputs);
- the level of customer support for the business's proposed action to manage the risk and the quality of that customer engagement (started as part of our stakeholder consultation undertaken to date and a major focus of our work between this Draft Plan and the submission of our Final Plan on 1 July 2022); and
- analysis of the price impact for the business's proposed action (a key part of the consumer choice model which we are developing and refining).

We have developed our approach around these seven requirements and we will continue to work on our approach, with stakeholders, in the coming months. Our Final Plan will reflect the detail of the entirety of our approach so that it can be assessed against the AER's requirements.

The AER's Information Paper also notes the possibility of using trigger mechanisms to re-open access arrangements to address uncertainty (for example if a government were to implement an electrification policy). We will consult on this issue and give further consideration to possible trigger mechanisms as we continue to develop our Final Plan.

7 Pipeline and reference services

Our proposed services for the next AA period are largely the same as those currently provided by the Victoria and Albury distribution networks.

IN THIS CHAPTER:

- **We propose to largely maintain the same suite of reference and non-reference services in the next AA period.**
- **Our proposed reference services include a range of haulage and complementary ancillary services.**

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

In the current AA period we have offered a number of different haulage and ancillary services.

The haulage services and most commonly used services ancillary to providing a haulage service have been classified as reference services – haulage reference service (HRS) and ancillary reference services (ARS). These services, which have accounted for over 99% of the revenue earned in the current AA period, are the basis of the reference tariffs approved by the AER in the current AA period.

A small number of less frequently used services have been classified as non-reference services, with the price reflecting the cost of providing the services by AGN.

Based on the stakeholder feedback received to date, we propose to largely maintain the same suite of reference and non-reference services we propose to offer in the next AA period.

The following sections provide further detail on the reference and non-reference services we propose to offer in the next AA period. Details of the price and other terms and conditions that will apply to the reference services are provided in subsequent chapters of this Draft Plan.

7.1 Regulatory framework

This Draft Plan describes all of the pipeline services that we can reasonably provide. It also specifies which pipeline services are proposed to be the regulated reference services we intend to provide, which must be consistent with the AER's Reference Service Proposal (RSP) decision, unless there has been a material change in circumstances.

On 1 July 2021 we provided our RSP to the AER for the next AA period.[10] This RSP was developed on the basis of feedback provided by our customers and stakeholders, and the reference service factors set out in the National Gas Rules.

The AER consulted on the RSP with stakeholders and in November 2021 approved our proposal.[11]

[10] See: https://www.aer.gov.au/system/files/AGN%20-%20AGN%20%28Victoria%20%26%20Albury%29%20Reference%20Service%20Proposal%20-%201%20July%202021.pdf
[11] See: https://www.aer.gov.au/system/files/AGN%20Vic%20Albury%202023%E2%80%9328%20-%20Reference%20service%20proposal%20-%20AER%20final%20decision.pdf

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 resolutions for other services; and
- The likely regulatory cost.

Customer and stakeholder engagement

When developing our RSP, we met with our VGNSR and RRG. Through this engagement process, we asked whether:

- the services offered in the current AA period met our customers' needs;
- the current reference services are appropriate to continue in the next AA period;
- if there were any additional services that should be reference services; and
- if there was support for alignment of services across the three network businesses.

Our reference groups generally supported the retention of the existing reference services and non-reference services for the next AA period as they met our customer's needs.

One member of our RRG suggested one additional service (Cross Meter Investigations) should be classified as an ARS. However, given the low demand we considered it should remain as a non-reference services at this point.

No additional services were considered necessary by reference group members.

After submitting our RSP, the AER provided stakeholders an opportunity to comment before making its final decision. The AER received one submission, which focussed on promoting price transparency on our non-reference services. Providing cost transparency to our customers is embedded in our existing processes, however we will continue to improve our processes to ensure our services meet our customers' needs, and customers understand how the cost of those non-reference services have been determined.

7.2 Pipeline services

Table 7.1 sets out the reference and non-reference services we propose to offer in the next AA period and are consistent with the AER's RSP decision.

The classification of the services in this table as either reference or non-reference services is largely consistent with the classification that applies in the current AA period. It is also consistent with our July 2021 RSP, which the AER approved in November 2021.

As Figure 7.1 shows, the proposed reference services have accounted for over 99% of the revenue earned by AGN between 2016 and 2020, while non-reference services have accounted for around 0.5%. What this means is that the AER determines the price we charge for services that make up over 99% of our revenue.

7.2.1 Reference services

In the next AA period, we propose to offer two haulage services and six ancillary services as reference services (refer Table 7.1).

Our haulage reference services, which is the delivery of gas to our AGN customers fall into two categories:

- volume haulage service, delivering gas to around 705,000 residential and 25,000 commercial customers; and
- demand haulage service, delivering gas to over 270 industrial customers.

The proposed reference services remain the same as those in the current period, with one non reference service (Appointment for Special Meter Read) proposed to be classified as an ARS in the next AA period.

Consistent with the reference services factors, these services:

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

7.2.2 Non-reference services

In the next AA period, we also propose to offer several non-reference services.

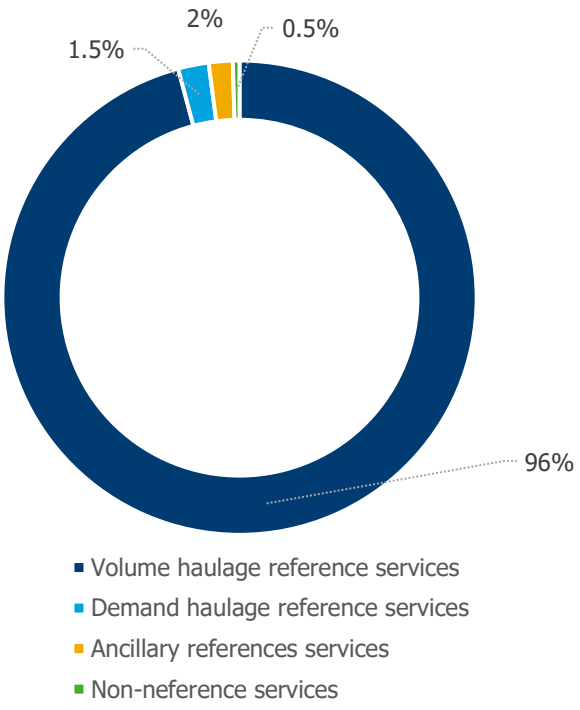
These services have been classified as non-reference services because, in contrast to reference services:

- they are generally substitutable with other services;
- the demand for these services is relatively low and in most cases unpredictable; and/or
- the cost of providing most of these services varies markedly depending on the specific customer requirements.

We are proposing to treat two existing non-reference services that are currently classified as Other non-reference services as separately identified non-reference services in the next AA period.

While we are not proposing to define these services as reference services in the next AA period, we understand customer preferences are changing. We will therefore re-evaluate the classification of services for the subsequent AA period and consult with our stakeholders at the time.

Figure 7.1: VIC & Albury distribution network share 2016 to 2020



7.3 Summary

We propose to largely maintain the current set of reference and non-reference services in the next AA period. Our customers support this approach, which is also consistent with our RSP approved by the AER in November 2021.

Table 7.1: Summary of pipeline services for the Victoria and Albury distribution networks 2023/24 – 2027/28

Service	Description
Haulage Reference Services	
Volume Haulage Service	The delivery of gas to through an existing Volume Delivery Point (DP). A DP is a volume DP for a given period if it is not a Demand DP.
Demand Haulage Service	The delivery of gas through an existing Demand DP. A DP is a Demand DP if the Quantity of Gas delivered at that DP has either: • exceeded 10 TJ in the preceding 12 month period (or, if less than 12 months of data is available, 10 TJ reduced in proportion to the period for which data is available as a proportion of 365 days); or • exceeded 10 GJ in any hour during the preceding 12 months.
Ancillary Reference Services	
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.

Service	Description
Disconnection	Disconnection by the carrying out of work using locks or plugs at a Metering Installation in order 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 Removal	Removal of a meter at a Metering Installation in order to prevent the withdrawal of 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.
Special Meter Read	Meter reading for a DP that is in addition to the scheduled meter reading that forms part of the Haulage Reference Service. This service also includes a service request for an appointment to read a meter.
Non-reference Services	
Same day premium charge	Used for jobs requested to be done on the same day. This premium is in addition to the original job charge like the reconnection service.
Disconnect service in street for debt – requiring excavation	This may be requested by RB, or by Distributor as a matter of safety, when disconnection of supply is intended to be longer term due to non-payment of outstanding account by consumer.
Incomplete Meter Fix	Original Meter Fix request was unable to be completed on appointment date due to site not ready and includes 'no access to site' or appliances not installed.
Alter Meter Position	To be used when a customer is requesting the relocation of an existing gas meter to a new position.
Attend meter fix after faults rectified	Where a consumer requests a meter to be connected to a property where the gas main and service pipe are already connected.
No Access (gas meter)	Field crew could not gain access to the property on the agreed day to perform the service.
Other non-reference services	Any other non-reference service requested by the customer or retailer and which the Service Provider agrees to provide.
Cross Meter Investigations	Used when investigating Cross Meter enquiries - charged if not a Crossed Meter.
Reconnect Service in street after payment	Used to request reconnection of gas supply, previously disconnected in the street, following satisfactory payment by consumer (or other agreed arrangement).
Relocate service pipe	Used to relocate the service or "Inlet" pipework.

Service	Description
Upgrade service request	Used when the increased gas load requires a larger capacity of service line to be installed.
Downgrade Meter Size	To be used where a retailer requests a customer's meter to be downgraded.
Pressure Change	To be used when a customer requests a change in gas pressure and may involve a regulator.

8 Operating expenditure

Our operating expenditure will ensure we maintain the strong performance our customers value, provide tailored support to customers in vulnerable circumstances and communicate our plans for decarbonisation.

IN THIS CHAPTER:

- **Our opex forecasts have been developed using the base-step-trend methodology approved by the AER.**
- **We have delivered real opex savings of around 4% compared to our benchmarks, while also servicing a forecast 82,000 net additional customers. Lower costs and higher connections will benefit customers in the next period.**
- **We are proposing two new opex initiatives in the next AA period which we have developed with our customers and stakeholders; our priority service program and renewable gas communications.**

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 and the day-to-day needs of our workforce.

Consistent with our approach in previous reviews, we have adopted the AER's base-step-trend methodology. This means for most opex items we look at the total costs we are incurring now and project those costs forward, but for some items we develop specific forecasts giving consideration to the individual factors that drive those costs.

On an aggregate basis, our opex is forecast to be $455 million over the next AA period (see Table 8.1 and Figure 8.1). Excluding the effect of our proposed changes to the approach to the capitalisation of some overheads and other activities, this is around 11% ($40 million) higher than the $365 million we expect to incur in the current AA period (forecast to December 2022).

This increase can be attributed to the increasing costs we have incurred over the current AA period from 2018 to 2021, such as higher safety levies, along with new activities in the next AA period including an uplift of our cyber security, renewable gas communications and our priority services program. For most other categories we have been able to keep costs at similar levels, despite servicing an additional 82,000 customers in the current AA period and a further 69,000 forecast for the next AA period.

Table 8.1: Total forecast opex ($million, 2022/23)

Category $m June 2023	Current AA period	Next AA period	Drivers
Base year opex excluding Debt Raising Cost (DRC)		374.9	✓ Overall real cost saving of ~4% compared to benchmarks and reflecting real cost increases incurred between 2018 and 2021
Plus change in capitalisation of some overheads		35.7	✓ We have adjusted our base year for a change in the capitalisation of some overheads (i.e. have opted not to capitalise some costs, and kept them as opex)
Plus Trend		13.7	✓ Includes real labour cost escalation, output growth and 0.4% pa productivity growth
Plus Capex to opex step activites		14.1	✓ Activities previously treated as capex that are more akin to opex
Plus cyber security uplift step change		4.1	✓ We are uplifting our cyber security capabilities in line with the Australian Energy Framework and Security of Critical Infrastructure Act requirements
Plus renewable gas communication step change		7.4	✓ We are investing in a renewable gas communications package, as while 87% of customers consider decarbonisation as important very few know about the decarbonisation plans for the gas networks
Plus Priority Services Program		5.0	✓ Introduction of Priority Services Program (previously VCAP)
Total opex excluding DRC	**364.6**	**454.9**	

Figure 8.1: Comparison of opex

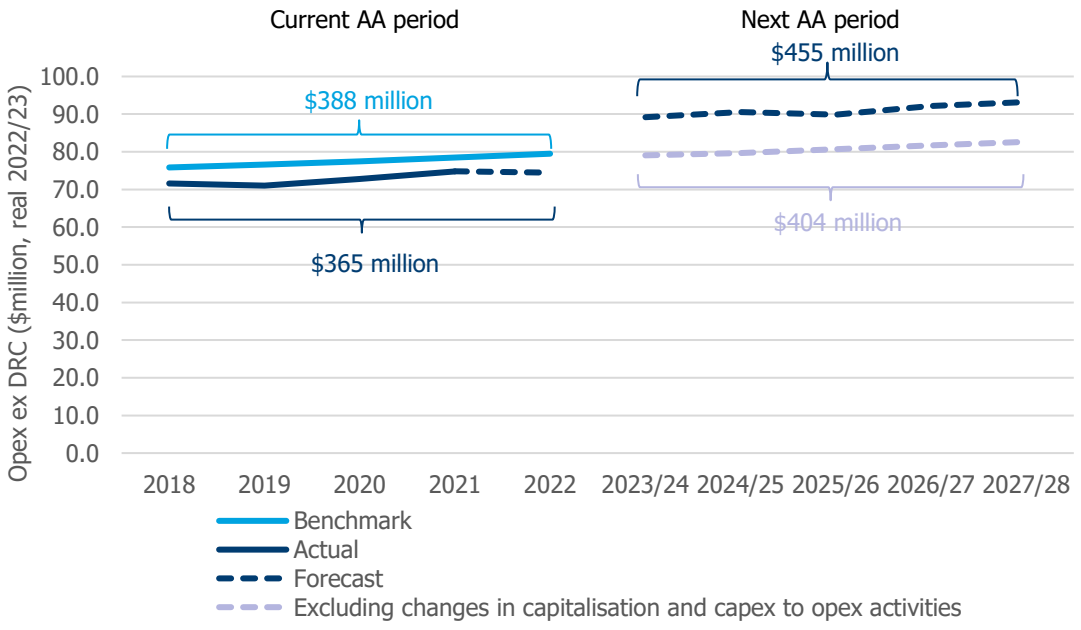


Figure 8.2 below shows a comparison of benchmark and actual opex per customer in the current AA period compared to forecast opex per customer. It shows that we have achieved a reduction in opex per customer in the current AA period compared to benchmarks and that opex per customer is also forecast to decrease in the next AA period, before the proposed changes in cost treatment and new activities. While new activities increase overall cost of service per customer by $4, the change in cost treatment represents a shift rather than an increase in total costs.

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. Further detail is also provided on how we have performed in the current AA period and how we ensure the expenditure we incur is both prudent and efficient.

All numbers quoted in this section are expressed in 2022/23 dollars, unless otherwise stated.

8.1 Regulatory framework

Our AA proposal must include the forecast opex for the next AA period.

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

Our forecasts 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

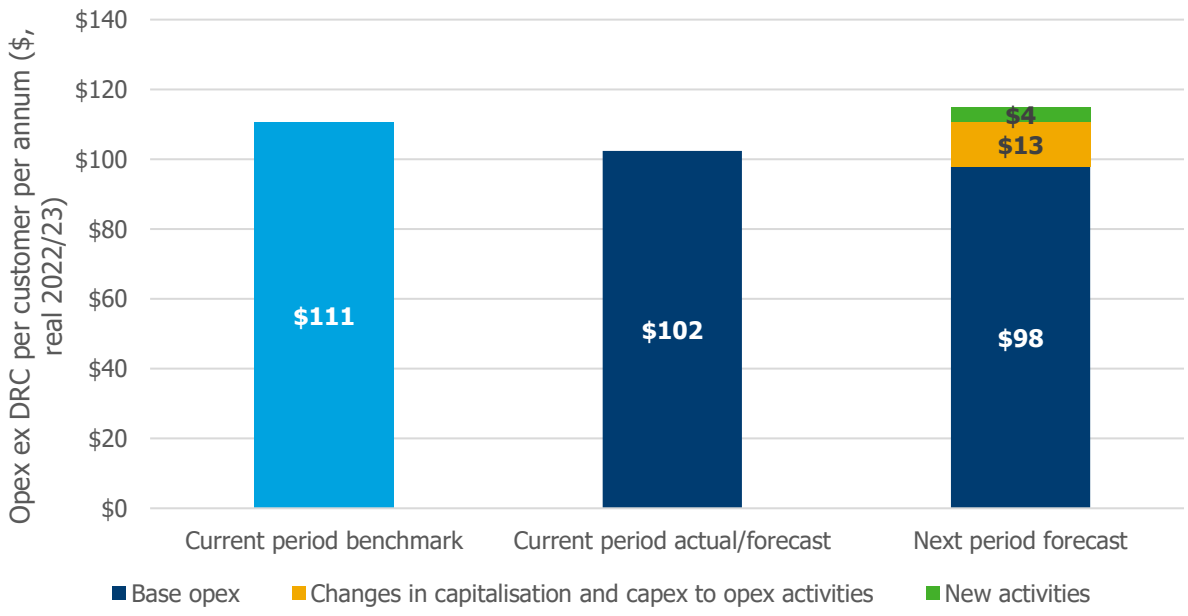
Customers told us they value their current gas supply and expect levels of public safety and reliability to be maintained. While price is the top priority for our customers, they are adamant lower prices should not compromise safety or reliability. With this in mind, our opex proposal focuses on maintaining current levels of safety and reliability.

When interacting with us, customers expect:

- responsiveness;
- effective resolution;
- professionalism;
- respect;
- simple and clear language;
- empathy; and
- patience.

Our opex proposal will ensure continued improvement in customer service experience in terms of inclusivity and accessibility of communications and new investment in a priority services program for customers experiencing vulnerability.

Figure 8.2: Comparison of opex per customer



Customers are concerned about climate change and protecting the planet for future generations. They expect us to reduce carbon emissions and are keen to understand more about the steps we are taking to deliver a cleaner energy supply. In response, we proposed investment in a renewable gas communications and education program as part of our opex in the next AA period. 74% of customers participating in our workshops were supportive of increased investment in this space at a level of $2-3 per annum bill impact. This will also help to reduce demand risk that may arise from uncertainty about the future our gas networks will play in a net zero carbon future.

We have developed our opex proposal in consultation with stakeholders. We presented our draft opex proposals to our VGNSR and RRG reference groups at various stages of its development between August and December 2021 to seek feedback on our investment priorities and levels of expenditure. Stakeholders were supportive of how we have developed our proposal.

Engagement insights

- ✓ Customers value their current gas supply and expect levels of public safety and reliability to be maintained.
- ✓ Customers consider gas as an essential service, especially for heating in the colder months in Victoria.
- ✓ Customers view safety as a non-negotiable.
- ✓ 95% of customers are satisfied with the reliability of their gas supply.
- ✓ 87% of customers view climate change and reducing carbon emissions as important or very important.

Engagement insights

- ✓ Customers expect AGN to be on the journey towards a cleaner energy supply and want insights and education on renewable gases.
- ✓ Customers are keen to better understand the cost implications for transitioning to renewable gas, including the need to switch appliances.
- ✓ 93% of customers thought it was either important or very important that we look at dedicated services for customers experiencing vulnerability, quoting the need for inclusivity and fairness.
- ✓ CALD customers noted the importance of translation services, empathetic and patient customer service and tailored communications.

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 for our opex excluding ancillary reference services, UAFG and debt raising costs (DRC). 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 priority service program).

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

Figure 8.3 illustrates the key elements of this approach.

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.

8.4.1 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 base 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 2021. At this point in time we do not have the actual costs for this year. We have therefore had to develop an estimate of the 2021 costs for this Draft Plan. This estimate is based on the actual opex incurred to September 2021 and a forecast for the remaining three months of the year.

When we submit our Final Plan to the AER on 1 July 2022, more information on our actual opex in 2021 will be available. We therefore intend to update this forecast with a full 12 months of actual data when we submit our Final Plan.

Removal of non-recurrent opex

As noted in Figure 8.3, once the base year costs are determined, they must be adjusted to remove any non-recurrent costs.

Unaccounted for gas (UAFG) costs in Victoria are the responsibility of the retailer. To incentivise us to

Figure 8.3: 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) for:

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

(ii) a full year of costs, where it is not currently reflected in the base year;

(iii) 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

(iv) 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. debt raising costs and priority services program)

maintain our network in a way that minimises gas losses, the Essential Services Commission in Victoria (ESCV) sets an efficient benchmark for UAFG. If losses are above the benchmark, we must pay the retailer for the additional gas it has had to purchase and vice versa, if losses are below the benchmark, we are compensated for the gas saved by the retailer.

As this can vary year-to-year, and the efficient level is deemed to be zero (i.e. UAFG on our network is in line with the benchmark and hence no payments between us and the retailer are required) we remove non-recurrent UAFG costs incurred in the base year. The adjustment for non-recurrent UAFG costs in 2021 is $1 million. All other costs incurred in 2021 are recurrent, therefore no further adjustments have been made.

Adjusting the base year to reflect a full year of costs for some recurrent activities

The base year may also be adjusted to reflect a full year of costs for recurrent activities which have not been incurred for the full year of the base year.

For AGN, the opex we have forecast to incur in 2021 reflects a full year of all recurrent activities, therefore no adjustments have been made.

Removal of opex categories to be forecast separately

The base year must also have removed those opex categories for which category specific forecasts are required to better estimate efficient costs. That is, the base step trend approach is not the appropriate method to forecast those costs.

As noted above, we have developed separate forecasts for the costs associated with ancillary reference service and debt raising costs. We have therefore excluded $3 million from the 2021 estimated expenditure to remove the costs associated with ancillary reference services and $1 million for debt raising costs.

Accounting for changes to capitalisation of overheads

The base year costs must also be adjusted to account for any changes in the treatment of costs.

Our capitalised overheads account for around $12 million of expenditure per year. These overheads relate to activities undertaken by our lead contractor, APA, such as:

- management costs associated with the administration, supervision and controlling of capital projects;
- network analysis, design, mapping and costing support in relation to network extensions and modifications;
- 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.

We have reviewed the activities included within our overhead costs which we have typically capitalised. We have identified a portion of these activities which are more akin to operating expenditure than capital expenditure, and we therefore propose they be treated as operating expenditure going forward. These activities are:

- management costs associated with the administration, supervision and controlling of capital projects; 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, $8 million of the forecast capitalised overheads for 2021 have been included in the base year opex. This results in a $35 million increase in the five year base expenditure. An offsetting change has also been made to our capex forecast for the next AA period, resulting in a capitalised overhead rate of 4% compared to 10% in the current AA period.

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

Reclassifying these activities as opex will also have the benefit of assisting to maintain the long-term competitiveness of gas by reducing the growth in our asset base.

Base year opex used for forecasting

The base year opex that we have used for the purposes of the Draft Plan is $78 million. As noted above, this amount will need to be updated ahead of the Final Plan to reflect the actual costs incurred in the full 12 months of 2021.

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 EBSS (see Chapter 12), 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.

To this end, the AER noted in its decision for the current period that:

"AGN's opex was subject to the incentives of an ex ante regulatory framework, including the application of an efficiency carryover mechanism in the 2013–17 period. Typically, where a service provider is subject to these incentives, we are satisfied there is a continuous incentive for a service provider to make efficiency gains and it does not have an incentive to increase its opex in the proposed base year. Taking this into account, and in the absence of any evidence to the contrary, we are satisfied AGN's proposed 2016 base year reflects its year-to-year opex requirements."[12]

The costs we incur in the base year will therefore provide a prudent and efficient basis for forecasting opex in the next AA period.

Table 8.2: Establishing the base year for forecasting opex in the next AA period ($million, 2022/23)

Category	2021 forecast
Total opex	76.0
Minus UAFG and provisions	0.8
Minus category specific forecasts (debt raising costs and ancillary reference services)	4.4
Base year opex	**70.9**
Plus change in capitalisation of overheads	7.1
Base year for forecasting	**78.0**

8.4.2 Step changes and Capex to Opex Activities

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 as a result of changes to legislation, regulatory obligations, new activities or where it is efficient to substitute capex with opex.

Step Changes

While we have identified a number of potential step changes in opex over the next AA period, we don't intend to seek additional funding for all of these at this time.

One new activity we are exploring in response to customer feedback that we need to decarbonise gas supply is our renewable gas communications and education program.

While 87% of customers who participated in our workshops view climate change and reducing emissions as important or very important, we found few customers were aware of our decarbonisation plans. The renewable gas communications and education program is focussed on getting the message out there about the renewable pathways for gas distribution networks and what this means for our customers now and in the future.

Based on customer support and feedback in our second round of workshops, we will deliver a broad scale media campaign and grass roots community and school-based activities at a forecast cost of $7 million in the next AA period.

A summary of positive step changes we expect in the next AA period, and how we intend to treat them, are:

- higher IT opex driven by continuing requirements to improve our cyber security ($4 million), as well as the new platform that will support digital customer services – opex step change for cyber uplift, absorb digital customer services; and
- a new renewable gas communications and education program ($7 million) –opex step change.

[12] AER, "Attachment 7: Operating Expenditure | Draft Decision Australian Gas Networks Victoria and Albury gas access arrangement 2018 to 22", July 2017, p 12.

Table 8.3: Opex step changes in the next AA period ($million, 2022/23)

Category	Total AA
Cyber uplift	4.1
Renewable gas communications	7.4
Total step changes	**11.5**

Capex to Opex Activities

In addition to the step changes outlined, we have also identified programs previously classified as capital expenditure but would better fit the definition of opex, making them a transfer of costs from capex to opex.

These capex to opex activities have been developed and forecasted using a bottom up approach.

The activities include;

- a HDPE assessment where 110 samples will be collected from the HDPE network and assessed to determine the remaining life of these mains, which will inform ongoing asset management required in future AA periods;
- reactive mains replacement where we reactively repair or replaced small sections of mains where needed;
- inline inspection of transmission pipelines using a tool called a pig;
- direct current voltage gradient survey and coating repairs on pipelines; and
- process safety revisions.

Table 8.4: Capex to Opex transfers in the next AA period ($million, 2022/23)

Category	Total AA
HDPE Assessment	1.3
Reactive Mains Replacement	3.5
Pipeline Inline Inspection	3.7
DCVG Survey & Coating Repairs	5.0
Process Safety	0.6
Total Capex to Opex	**14.1**

8.4.3Trend

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 as a result of:

- 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.

While we are still having some work undertaken by independent experts on these factors, for the purposes of the Draft Plan we have assumed a trend rate of change of 1.2% per year.

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: [13]

- labour costs are assumed to account for 59.2% of our opex and are forecast to grow in real terms by an average annual rate of 0.6% per year over the next AA period; and
- materials costs are assumed to account for 40.8% of our opex 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 the average of the Wage Price Index forecasts for Electricity, Gas, Water and Wastewater Services developed by BIS Oxford and Deloitte Access Economics (as shown in Table 8.5).

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

The application of these assumptions results in a real (i.e. before inflation) average annual input cost escalator of 0.4% per year over the next AA period (see Table 8.6).

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 has been calculated having regard to the forecast growth in:

- customer numbers over the next AA period; and

[13] These weights are based on the AER's benchmark weights.

- kilometres of network over the next AA period.

The forecast customer numbers and kilometres of network added over the next AA period are set out in Chapters 9 and 13. We have applied weights to each factor 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 1.2% per year over the next AA period (see Table 8.7).

This is consistent with the approach recently approved by the AER for Jemena's New South Wales gas distribution network and our AGN South Australia gas distribution network.

We consider this approach reflects the drivers of our costs.

Productivity growth

In applying the base-step-trend approach, the AER considers whether there should be an adjustment to capture expected changes in the productivity of the business (which could be positive or negative).

Table 8.5: Calculation of annual real labour cost escalation

Labour cost estimates	2023/24	2024/25	2025/26	2026/27	2027/28
BIS Oxford (A)	0.92%	1.37%	1.53%	1.03%	0.84%
Deloitte Access Economics (B)	0.17%	-0.14%	-0.12%	0.21%	0.03%
Annual labour cost escalation (average of A and B)	**0.55%**	**0.62%**	**0.71%**	**0.62%**	**0.44%**

Table 8.6: Calculation of annual input cost escalation (weighted average of real cost escalation for labour and materials)

Category	Weight	2023/24	2024/25	2025/26	2026/27	2027/28
Labour	59.2%	0.55%	0.62%	0.71%	0.62%	0.44%
Materials	40.8%	0.00%	0.00%	0.00%	0.00%	0.00%
Annual input cost escalation		**0.32%**	**0.36%**	**0.42%**	**0.37%**	**0.26%**

Table 8.7: Calculation of the output growth factor

Category	Weight	2023/24	2024/25	2025/26	2026/27	2027/28
Customer numbers	50.6%	1.38%	1.31%	1.35%	1.49%	1.64%
Network length (km)	40.4%	1.02%	0.96%	0.99%	1.10%	1.14%
Weighted output growth factor		**1.20%**	**1.14%**	**1.17%**	**1.30%**	**1.39%**

Table 8.8: Calculation of output growth net of productivity growth

Category	2023/24	2024/25	2025/26	2026/27	2027/28
Weighted output growth factor	1.20%	1.14%	1.17%	1.30%	1.39%
Annual productivity	0.40%	0.40%	0.40%	0.40%	0.40%
Annual output growth net of productivity	**0.80%**	**0.74%**	**0.77%**	**0. 09%**	**0.99%**

In this Draft Plan, we have applied annual productivity growth of 0.4% per annum. This is based on the value accepted in our South Australian network and work we engaged ACIL Allen to undertake on productivity trends.[14]

There is some evidence in ABS statistics of a slowdown in productivity over the past year, since our South Australian network decision, and we will consider this evidence in our Final Plan. However, for this Draft Plan, we have adopted the same value as applied for our South Australian network. The application in this Draft Plan of a productivity growth factor of 0.4% per year over the next AA period results in a $5 million reduction in total opex when compared with a factor of 0% as was applied in the current AA period.

8.4.4 Category specific forecasts

As noted above, separate forecasts have been developed for ancillary reference services and debt raising costs. We are also proposing a new category specific forecast for our priority services program.

The priority services program is based on our recently approved vulnerable customer assistance program developed in our AGN South Australia AA. In line with the AER's Final Decision for that network we have included this program as a category specific forecast so that the costs and activities delivered within this program can be separately tracked.

The way in which each of these costs have been forecast is outlined below.

Ancillary reference services

Ancillary reference services (ARS) are services such as special meter reads, meter relocations or disconnections and reconnections that may be required by individual customers from time to time.

Our ARS forecast has been calculated by multiplying:

- the average annual volume of each ARS in the last three years; by
- the forecast average cost of providing each ARS.

We forecast to spend a total of $21 million for the provision of ARS in the next AA period.

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 has been calculated using the AER's standard benchmark method.

The application of this method produces a debt raising cost forecast of $4.5 million in the next AA period.

Priority services program

Our priority services program is a new program which provides tailored services and support to customers facing circumstances of vulnerability.

This program is being introduced in Victoria for the first time in response to customer and stakeholder feedback that supporting customers facing vulnerable circumstances is important to them.

We forecast a total of $5 million in the next AA period to deliver this program. The costs have been forecast using a bottom-up approach for a program of activities which have been co-designed with our customers and stakeholders.

8.4.5 Summary

Figure 8.4 and Table 8.9 set out our forecast opex for the next AA period.

As this table shows, we expect to incur $459 million in opex over the next AA period. This is $40 million (or 11%) higher than what we expect to incur in the current AA period (forecast to 31 December 2022).

The increase can largely be attributed to the proposed change in treatment from capex to opex of:

- Over half of the previously capitalised overheads;
- HDPE assessment program;
- Reactive mains replacement;
- Pipeline Inline Inspection;
- DCVG Survey & Coating Repairs; and
- Process Safety.

[14] AGN South Australia, Five year plan for our South Australian network, Final Plan, July 2020, Attachment 7.3.

The proposed change reflects that the identified activities are better described as operating activities. Importantly, the proposed amendments do not change our combined total expenditure (i.e. opex plus capex) forecast for the next AA period, just their assignment to either opex or capex.

Excluding the effect of the changed capitalisation policy, proposed step changes and capex to opex transfers, our opex in the next AA period is around 11% ($16 million) higher than what we expect to incur in the current AA period.

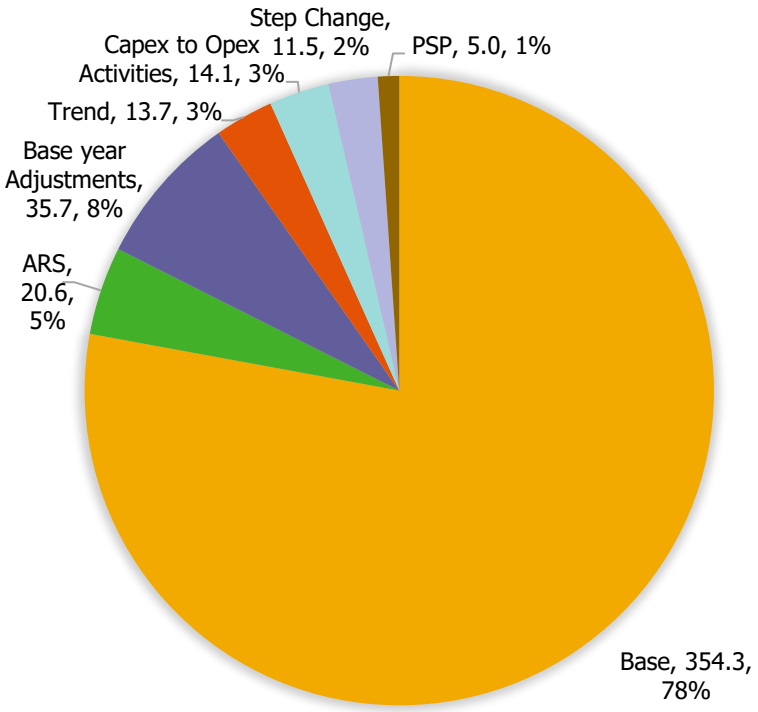
As noted above, we will need to make some revisions to this opex forecast when submitting our Final Plan to the AER.

We will, for example, update our estimate of the 2021 base year costs with the actual costs incurred in that year, once the information is available.

Our opex in the next AA period aligns with our vision by:

- delivering for customers – we will respond to leaks on our network (one of the most important activities we undertake to ensure public safety) and maintain our network assets as required by our asset management plans (AMPs), along with other operational activities to maintain our safety, reliability and customer service performance;
- being a good employer – we will undertake workplace health and safety programs, and employee and contractor training and development initiatives to maintain a healthy, safe and skilled workforce; and
- being sustainably cost efficient – we will pass through opex savings made in the current period to our customers and incur similar levels of opex to that incurred in the current AA period (excluding the effect of the change in capitalisation policy), while facing upward cost pressures and servicing a larger customer base.

Figure 8.4: Opex in the next AA period by category ($million, $2022/23)



The following sections provide more information on two key areas of our opex proposal which have been developed in response to the insights and feedback from our customers in the first two rounds of customer workshops:

- our priority services program to provide additional support to customers facing circumstances of vulnerability; and
- our new renewable gas communications program which focusses on getting the message out there about renewable pathways for gas distribution networks and what this means for our customers now and in the future.

In particular, we are seeking customer feedback on these additional initiatives to ensure they deliver on the expectations communicated to us by our customers.

Table 8.9: Opex forecast summary ($ million, 2022/23)

	2023/24	2024/25	2025/26	2024/25	2025/26	Total
Base year opex	70.9	70.9	70.9	70.9	70.9	354.3
Change in capitalisation of overheads	7.1	7.1	7.1	7.1	7.1	35.7
Base year	**78.0**	**78.0**	**78.0**	**78.0**	**78.0**	**390.0**
Capex to opex activities	2.9	3.5	1.8	2.9	2.9	14.1
Trend	0.9	1.7	2.7	3.7	4.7	13.7
Ancillary Reference Services (ARS)	4.1	4.1	4.1	4.2	4.2	20.6
Step changes	2.2	2.2	2.3	2.4	2.4	11.5
Priority services program (PSP)	1.1	1.0	1.0	1.0	1.0	5.0
Total opex forecast (ex debt raising costs)	**89.2**	**90.5**	**89.9**	**92.2**	**93.2**	**454.9**
Debt raising costs	0.9	0.9	0.9	0.9	0.9	4.5
Total opex	**90.1**	**91.4**	**90.8**	**93.1**	**94.1**	**459.4**

8.5 Priority services program

This section sets out our plans over the next AA period to improve services for vulnerable customers.

As discussed in Chapter 2, we are one of the founding businesses across the energy supply chain who have committed to the Energy Charter. The Energy Charter seeks to bring energy business together to deliver energy for a better future, which includes supporting customers facing a vulnerable circumstance as a key principle.

We know affordability and helping those in need is important to our customers and stakeholders. In fact, 93% of customers said that providing dedicated services to vulnerable customers was important or very important. Figure 8.5 summarises the key customer insights on priority services for customers facing circumstances of vulnerability from our customer workshops.

Customers in vulnerable circumstances can include people with a disability, those who are chronically sick, older Australians, and also those in financial hardship.

We have been actively engaging with our Priority Service Advisory Group, comprising of experts in the social service sector, through a series of workshops to develop potential new ways in which we could support Victorians and people in Albury experiencing vulnerability.

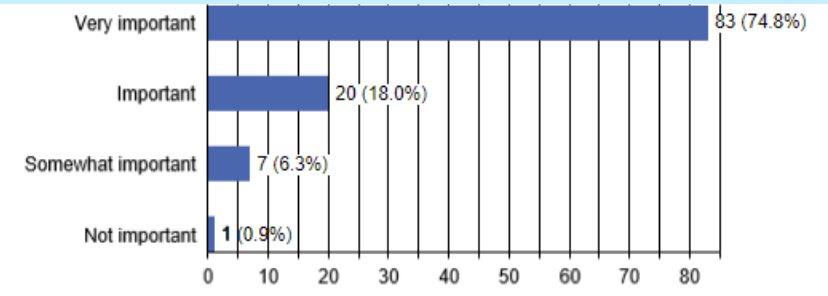
Figure 8.5: Customer insights on priority services for customers facing circumstances of vulnerability

Customers value having flexible payment options and financial support to make gas more affordable.

- Changing circumstances brought about by Covid-19 have introduced financial hardship to a new cohort.
- Customers desire flexibility, with some preferring more frequent payments to accommodate their budgeting process.
  - Customers desire more financial concessions for vulnerable communities.
  - "Lots of communities are struggling with bills"

Vulnerable customers require tailored safety measures.

- There is a need for alternative safety measures for vulnerable members of the community (i.e. elderly and those with medical conditions).
- ***"I have a form of dementia, we have a gas stove and had to put a switch on it as I forget to turn the gas off. I can't smell either, what is an alternative form of detecting gas?"***
- Diversity of the community means native language preferences exists.
- CALD customers value having communications offered in their native language.
- They also desire more accessible education on gas safety, particularly for customers that are new to Australia.
- "When English isn't a first language, we need to make information available on using gas appliances safely"
- Perceived importance of providing dedicated services to customers who might be vulnerable



In the first workshop, we explored various elements of the Priority Services Program including the role of networks businesses, existing support available in Victoria and possible initiatives. We also confirmed the six key needs of customers experiencing vulnerability shown in Figure 8.6.

In the second workshop, we sought to refine our plans with stakeholders. We presented the three key streams of activities shown in Figure 8.7 which we considered could address these needs and asked if we had missed any potential initiatives. We then went through each of the activities and asked:

- Would this duplicate an existing program?
- How would you rate the customer benefits of this program?
- Are we missing any benefits or implementation considerations?

Figure 8.7: Key needs for a Priority Services Program

Figure 8.6: Potential Priority Services Program initiatives

The feedback received to date has helped us to shape the draft program and we are now seeking further stakeholder and customer feedback.

The proposed Priority Service Program is a new program for the next AA period, with the objectives of:

- Doing more to financially support our customers and improve affordability;
- Improving how we communicate with our priority services customers, especially CALD customers; and
- Simplifying our processes to ensure that they are easily accessed by all.

To meet these objectives, we have identified the following potential initiatives, which were identified as having considerable customer benefit by members of our Priority Service Advisory Panel:

- The establishment of a **dedicated Customer Support role** within AGN, which will be responsible for resolving complaints involving our priority service customers, liaising with community organisations, developing referral programs for our customer service teams and implementing the new services included in the program.
- **Train front line staff** to engage with empathy and sensitivity and refer priority service customers to:
  - our program and other initiatives available from AGN to support them;
  - dedicated support services where available and required;
  - energy efficiency advice available through trusted organisations; and
  - Retailer programs that enable customers to 'self-read' their meter.
- **Improve our communications** with priority service and CALD customers by improving the accessibility of our communications, including by making information available in multiple languages using, easy English and using visuals where possible.
- **Ensuring optionality around communication channels** to ensure that priority service customers are able to choose how they receive our communications.
- Provide funding for:
  - Gas appliance safety checks;
  - Emergency appliance repairs; and
  - Emergency heating and cooking appliances during extended outages.
- The development of a **Priority Service Register** using an upgraded Customer Relationship Management System – this register will form the basis of a range of services to our priority customers. The development of this register would also mean that customers do not need to self-identify as vulnerable, which reduces the burden of providing proof and potential stigma associated with asking for support.

8.6 Renewable gas communications and education

Customers expect AGN to reduce carbon emissions and told us we should be doing more to communicate our renewable gas plans, and what this means for customers.

87% of customers view climate change and reducing emissions as important or very important, but very few customers are aware of our decarbonisation plans, with only around 15% of Victorians having heard of renewable gas.

In response to customer feedback that we should enhance our existing activities, three options were presented for further feedback:

- A standard campaign reaching 35% of customers which introduces the concept of renewable gas and includes a two-month television campaign, run twice per year (~$1 per customer per year).
- A medium campaign reaching 55% of customers which explains a renewable gas future, includes a two-month television campaign, run twice per year and some community events (~$2 per customer per year).
- A broad campaign which can be recalled by most Victorians, explains a renewable gas future, includes a three-month television campaign delivered three times per year, media partnerships, community events and a schools education program (~$3 per customer per year).

74% of customers participating in our workshops supported increased investment ($2 - $3 per annum) beyond our existing activities on more renewable gas communications and education activities.

We are also of the view that clear and informed customer education and communication is required to manage any major transitional change such as the shift away from natural gas to renewable gas. The low levels of customer awareness of our low carbon future support this. Related, if our customers are not aware of our future, they are more likely to choose alternate energy such as electricity, where awareness levels are far greater.

As a result, we have developed our Proposed Renewable Gas Communications Program (Figure 8.9). Our proposal incorporates customer feedback that a mix of community activities, school-based education and media and digital communications will enable us to reach most customers and provide engaging educational opportunities for all of our customers and the community.

We have also leveraged our recent experience implementing enhanced communications on our low carbon future to our South Australian customers which has delivered very positive results.

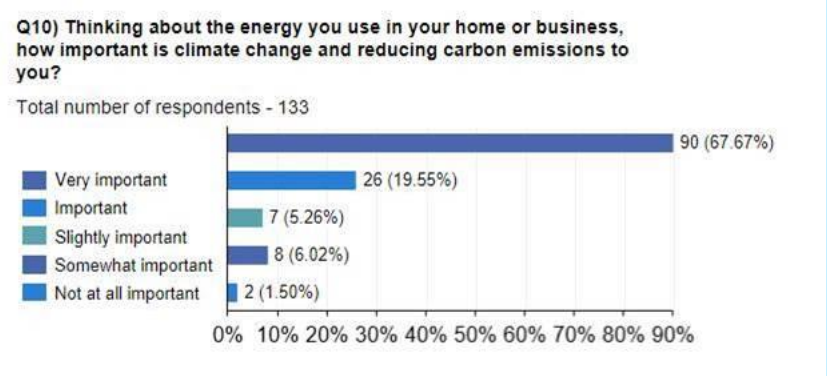
We consider that the proposed enhanced program is needed as it:

Figure 8.8: Customer insights on decarbonisation

Clean energy and reducing emissions is an important issue for customers. 87% of customers view climate change and reducing emissions as important or very important.

- Many customers emphasise the importance of protecting the planet for future generations.
- They expect AGN to be on the journey towards cleaner energy supply.
- Customers have low levels of awareness of renewable gas and are keen to learn more
- 74% of customers expect AGN to do more to communicate with customers on renewable gas, and are willing to pay $2-3 per annum for enhanced renewable gas communications

Importance of climate change and reducing carbon emissions (as ranked by customers during workshops)



- Allows customers to be informed, involved and engaged in the energy transition as it relates to gas
- Provides customers and communities the information they need to make informed choices about energy in their homes and businesses (e.g., appliances)
- Delivers against customer and stakeholder expectations that the future of gas is of critical importance to Victorians.
- Reflects prudent commercial practice to manage a major industry transition such as the shift to renewable gas.
- Is an appropriate and prudent investment to compliment technical and operational investments to support our low carbon strategy and the energy transition (See Future of Gas Chapter of this Draft Plan).

Figure 8.9: Our Proposed Renewable Gas Communication and Education Program

Customer communications

Our proposed communication campaigns would increase levels of customer awareness and education of renewable gas, and importantly, respond to key information our customers are seeking.

The communication campaigns would include information relating to renewable gas including how it can be blended into the network, and what this means for customers. It would also provide further information on key issues of importance for customers, including the timing for introducing renewable gas, what it means for reliability and safety of the network, gas appliance compatibility, and a pathway for the low carbon transition.

The communication campaign would include:

- ✓ Television, radio and digital media awareness and educational information reaching over 80% of households in Victoria
- ✓ Social media activity and as an interactive engagement channel for answering community questions and providing project updates.
- ✓ Supporting online materials as a key source of information on renewable gas

Community Activities

In addition to broad customer communications, we are proposing to engage at a community level and deliver tailored communications activities.

The program would include:

- ✓ Presentations and forums with community groups, including multicultural community organisations
- ✓ Site tours and presentations at renewable gas facilities
- ✓ Attendance at community events including sustainability and environment events, home shows and Science Fairs
- ✓ Regular communication through online resources, updates by way of regular newsletters and social media

Student Learning and Education

We are proposing a school education program as a key component of our communications and education program. We are looking to support Victorian school and tertiary education through a series of events and learning resources for students and teachers. Designed to align to the Australian Curriculum, the program would provide learning through individual programs that raise awareness of the role of gas networks businesses in reducing emissions across the energy sector. The program would focus on providing education and information on the need to reduce emissions across the energy sector, benefits of renewable gas, how it is used, a greater understanding of the science behind renewable gas production, the roadmap for decarbonising natural gas networks and renewable gas projects.

The program would engage with around 160,000 Victorian primary and secondary school students across the more than 2,000 schools, and 50,000 tertiary students.

The program would include:

- ✓ A combination of in person and digital/online resources
- ✓ Hands-on and interactive curriculum linked workshops through incursions and excursions
- ✓ Professional learning opportunities for educators
- ✓ Presentations and forums
- ✓ Attendance at student events including sustainability and environment events and Science Fairs
- ✓ Tailored activities for students where English is second language

8.7 Summary

Our proposed opex forecast of $455 million for the next AA period will ensure the gas network continues to operate safely and reliably, and will also include the provision of additional services such as the priority services program – an important initiative to assist our vulnerable customers. Our forecast combined total expenditure (opex and capex) for the next AA period is lower than that incurred in the current AA period in absolute terms and is lower again when considered on a per customer basis

Overall, our customers will continue to benefit from the opex savings we have achieved over the current AA period, as well as the new focus on supporting those facing vulnerable circumstances and communicating the transition of the network to delivering renewable gas.

Our opex forecast will also ensure that we:

- maintain our strong safety, reliability and service performance;
- have a healthy, engaged and skilled workforce; and
- are sustainably cost efficient into the future.

9 Capital expenditure

Our capex program focuses on maintaining safety and reliability, supporting customer growth and preparing our network for a decarbonised future.

IN THIS CHAPTER:

- **We will invest $544 million in the next AA period, which is 18% lower than current levels due to the completion of our low pressure mains replacement program.**
- **We are undertaking a program of augmentation works to support the continued growth we have seen (and will continue to see) in the north following the Hume highway, the south in Cranbourne and Clyde and a number of regional towns.**
- **We will connect a further 69,000 new customers to our networks.**

The capex we incur is required to ensure gas is supplied safely and reliably to existing and new customers connecting to our network with a high level of customer service.

Consistent with prior AA reviews, our capex forecast has been determined using a bottom-up approach.

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

Our capex net of customer contributions is forecast to be around $544 million in the next AA period, which is 16% ($100 million) lower than what we expect to incur in the current AA period (see Table 9.1).

This is driven by decreases in mains replacement, with expenditure on augmentation, transmission assets, and IT all forecast to increase compared to the current AA period. The capex forecast also includes a small amount (5% of proposed capex spend) to support the transition of the network to a decarbonised future. Joint work undertaken with the Australian Hydrogen Centre (AHC) has confirmed that while the network of pipes are largely hydrogen ready, there are some materials used within some regulators and meters that will require replacement.

Importantly, a major safety milestone for our business and our customers will be achieved before the next AA period with the completion of the replacement of all old low pressure mains in the network, including the Melbourne CBD. Not only has the program delivered safety benefits, the program delivers reliability benefits through fewer instances of water-in-mains events, and also reduced carbon emissions of 13,500 tonnes of CO_2-equivalent compared to 2017 levels per year.

Expenditure on our transmission assets will increase in the next AA period as we progress with modifying our older pipelines to make them compatible for in line inspection. In line inspection

Table 9.1: Actual and forecast capex by priority ($million, June 2023)

Priority	Current AA period	Next AA period	Highlights
Mains replacement	226.9	24.4	✓ Substantially lower mains replacement capex following completion of our low pressure mains replacement program in the current period ✓ Targeted replacement of 3.5km of high pressure steel mains in high-density coastal areas, 16.4km of camera inspection and reinforcement of our oldest HDPE 575 mains in Albury and Wodonga and renewal of 170 older material multi-user services
Growth assets	238.1	238.6	✓ Connection growth in line with independent dwelling growth forecasts and government policy
IT	45.4	89.5	✓ Uplift in cyber security, digital customer service and information management ✓ Transition and bring in-house a number of core IT systems toward the end of the period
Meter replacement	33.6	34.5	✓ In line with current levels and age of meter fleet
Augmentation	17.6	70.4	✓ Increased augmentation work to maintain minimum operating pressures in growing corridors in Melbourne's south east and northern suburbs and regional areas including Wodonga, Traralgon and Echuca
Telemetry	1.6	4.3	✓ Maintaining our SCADA network and network monitoring capabilities
Other assets	22.1	58.3	✓ Completion of alterations to two transmission pipelines, and a section of a third, to allow for in line inspection ✓ Ongoing replacement and refurbishing of valves and cased crossings ✓ No regrets expenditure to prepare our network for the decarbonised future
Escalation		2.6	✓ Real cost increases in inputs such as labour and materials
Overheads	58.8	21.1	✓ Project management, engineering and support costs associated with delivering the capital program
Total	**644.1**	**543.7**	

allows us to pinpoint potential integrity issues and target our maintenance and repair activities to ensure their continued safety and reliability.

The following sections provide further detail on our regulatory requirements, the forecasting method we have used and our capex forecasts for the next AA period. This chapter also provides an overview of how we have performed in the current AA period and how we ensure the capex we incur is both prudent and efficient.

All numbers quoted in this section are expressed in 2022/23 dollars including overheads and escalation, 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.[15]

Forecast capex must also satisfy various additional criteria,[16] including to:

- maintain and improve safety;
- maintain the integrity of the network;
- comply with our obligations;
- meet demand on the network;
- result in an overall economic benefit; or
- where additional revenue generated exceeds the associated costs.

Any forecast or estimate we provide must also be arrived at on a reasonable basis and represent the best forecast or estimate possible in the circumstances.[17]

9.2 Customer and stakeholder engagement

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

Across all three of the Victorian gas distribution networks, we found customers' key priorities are affordability, safety and reliability, customer service and preparing for the future. We presented our investment plans to customers with these priorities in mind.

Customers were happy with our track record of strong safety and reliability performance and were comfortable with our plans to maintain our safety and reliability performance.

When customers interact with us they expect us to be responsive and provide effective resolution. While customers prefer phone for priority services like a gas leak, digital communications (SMS), which are not currently available were preferred for updates on outages and new connections. SMS for communications appealed to many customers for its convenience and the ability to receive instant notifications. It is also a high valued communication tool by CALD customers and senior Australians. Customers also told us they are looking for new digital ways to manage their gas usage and reduce their bills.

Knowing affordability is a top priority, we presented a number of varying options, with different cost impacts, that could improve the way we deliver customer service, including by more digital channels. When presented with these options 57% of customers support investment in SMS technology for communications at a level of $2.50 per annum bill impact. The remaining 43% supported website and email enhancements, as they considered the additional cost of SMS too high given the low frequency of interactions.

We have developed a digital customer experience program for the next AA period to deliver on these customer needs.

We also discussed potential digital metering options with customers (technologies and likely costs) and asked what benefits they would see from more digital metering. We have proposed to replace around 3,600 hard to read meters with new meters that are read remotely and undertake a trial of digital meters in Albury/Wodonga as a first step for digital metering. This will reduce estimated reads which we know are a particular pain point for our customers and will provide us with more information that may support the wider roll out of digital metering options across our network.

87% of customers participating in our workshops view climate change and reducing carbon emissions as important or very important. Customers expect us to be on a journey to reducing emissions and delivering a cleaner energy supply. The balancing of affordability and sustainability of gas services has also been a strong theme throughout our engagement activities. 89% of customers who participated in our workshops were supportive of our proposed approach to preparing our networks for renewable gas.

In this Draft Plan we have presented additional detail on the investment in no regrets actions we plan to make over the next five years, which we have been developing with the Australian Hydrogen Centre simultaneously to this process. This information will enable further engagement with our customers and stakeholders on these aspects of our proposal and to ensure it is reflective of their values.

A summary of customer insights that relate to our capex investment plans is provided in Table 9.2 below.

Table 9.2: Customer insights for our capex plans

Insights
✓ Customers value their current gas supply and expect levels of public safety and reliability to be maintained.

[15] NGR 79(1)
[16] NGR 79(2)
[17] NGR 74

Insights

- ✓ Customers consider gas as an essential service, especially for heating in the colder months in Victoria.
- ✓ Customers view safety as a non-negotiable.
- ✓ Customers prefer phone for priority services like a gas leak, whereas digital communications (SMS) are preferred for updates on outages and new connections.
- ✓ 87% of customers view climate change and reducing carbon emissions as important or very important.
- ✓ Customers expect AGN to be on the journey towards a cleaner energy supply.
- ✓ Customers have little understanding of the makeup of their gas bill and are keen for more education and transparency.
- ✓ Customers are looking for new digital ways to manage their gas usage and reduce their bills.

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 wear and tear of our assets.

Figure 9.1 shows our actual and forecast capex over the current and next AA period. The completion of the low pressure mains replacement program is a key driver in the decrease we are forecasting compared to our current expenditure.

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 and program 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.

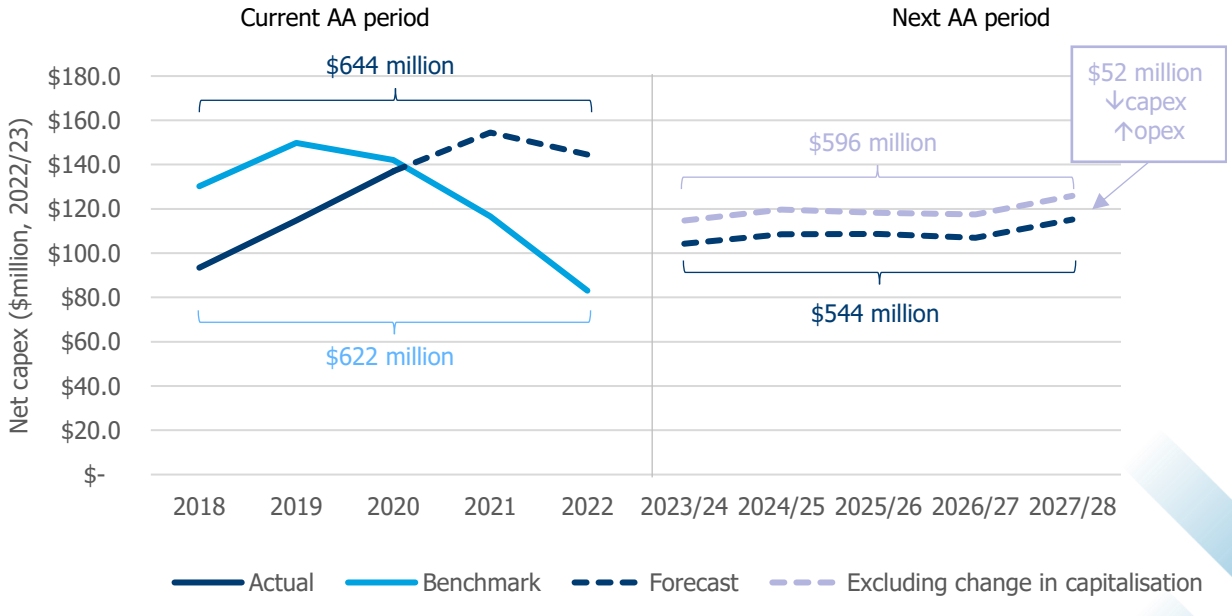
9.4.1 Determining our investment priorities

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 obligations.

Mains replacement in the next AA period will be modest and targeted at localised issues. This follows a significant replacement program of old cast iron and PVC low pressure mains that has been a key focus in the current and prior AA periods.

We are also investing in a number of new projects, such as digital experience, a digital/remote meter reading solution and a hydrogen network readiness program.

Figure 9.1: 10 year capex



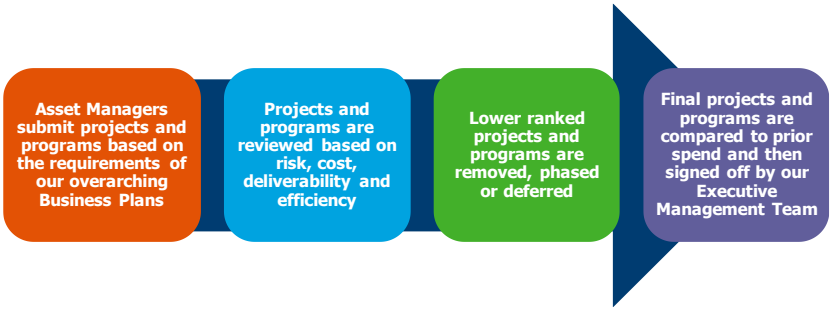
The process we use to identify the projects to be carried out is shown in Figure 9.2.

As this figure shows, potential projects and program activities are identified by asset managers having regard to our overarching Business Plans such as our 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.

Full business cases are then developed for the higher ranked programs and projects that are proposed to be delivered within the regulatory period. This allows a more detailed assessment to be undertaken of the options to address the identified problems, the costs of the options and the consistency of the selected option with the relevant provisions in the NGR. Lower ranked projects and programs, on the other hand, are deferred.

Figure 9.2: Summary of capex planning process



9.4.2 Forecasting efficient costs

Our forecast costs must be efficient, reasonable and represent the best possible forecast or estimate in 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 – new estates, existing homes and industrial and commercial (I&C) customers;
  - Services – new homes, multi-user sites, existing homes and I&C customers; and
  - Meters – new domestic and I&C customers' meter connections;
- Meter Replacement – periodic meter change (PMC) (also known as time expired meter replacement), domestic and I&C meters; and
- Mains Replacement – camera inspection and repair of High-Density Polyethylene (HDPE) 575, high pressure small diameter steel mains replacement, multi-user service renewals and piecemeal mains replacement.
- Unit rate prices are based on a range of information sources including:
- tender or contract information which has been tested through a competitive market process;
- current actual rates or a historical average rate (i.e. over the last three years of the current AA period) achieved for similar work; and
- both internal and external specialist engineering estimates.

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 may be based on tender or contract information, current actual or historical costs for similar works or specialist engineering estimates.

9.4.3 Escalation

Our forecast capex costs are developed in real dollars as at June 2021. To escalate these costs to real dollars as at June 2023 we apply two years of inflation. We also incorporate real cost escalation of inputs, such as labour, across the next AA period. There are two types of labour typically employed to deliver our capital program. These are specialised Electricity, Gas, Water and Wastewater Services (EGWWS) labour and Construction Services labour. For each type of labour, we apply the average of two independent real labour price forecasts to escalate costs. For material and non-labour cost components, zero real cost escalation is applied.

9.4.4 Capitalised overheads

We undertake a number of activities and support services within our business that contribute to the delivery of our capital program. The costs of these activities and support services that are attributable to capital works are capitalised and applied as a capital overhead across the program.

As discussed in Chapter 8, we are proposing to reduce the scope of activities and support services that are capitalised as an overhead across the program. The activities that will make up the capitalised overhead in the next AA period are planning and system design, technical and compliance services and network engineering.

On average, 73% of overhead costs of these activities are fixed and 27% vary depending on the total size of our capital program. Based on current costs and the comparative size of our capex program in the next period, we forecast $21 million of overhead (or around 4%).

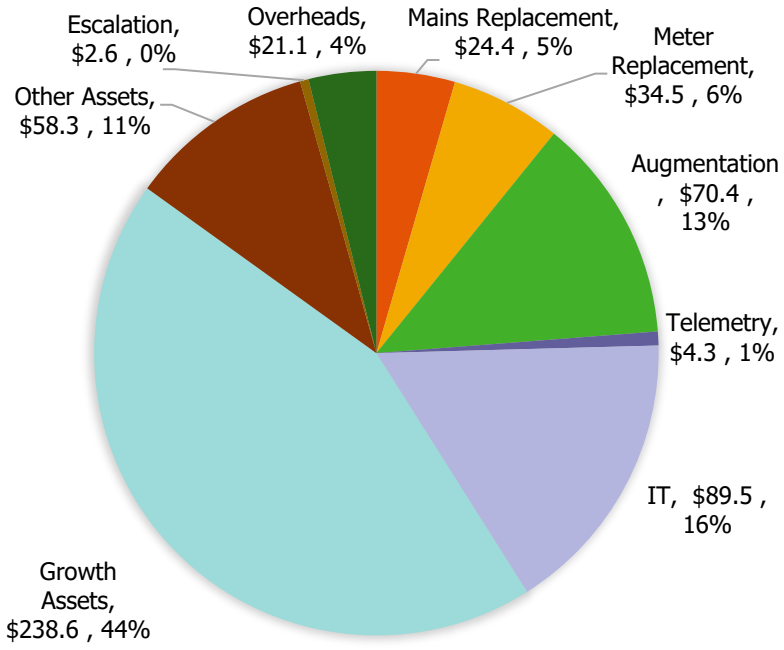
9.5 Capex drivers in the next AA period

The following sections provide further detail on the capex drivers and 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. These business plans and business cases assess the options considered to address the identified issue, the estimated cost of each option, the untreated risk each option would result in, the alignment with both our vision and the capex requirements of the NGR.

Individual business cases will form part of our Final Plan submitted to the AER in July 2022.

Figure 9.3: Capex by driver over the next AA period ($million, 2022/23)



9.5.1 Mains replacement

Despite the mains replacement program falling from $272 million in the current AA period to a forecast of $25 million in the next AA period, mains replacement and monitoring remains a key focus for the business as it is the single most important activity we undertake to ensure public safety. We will invest $25 million to:

- Replace 3.5 km of high pressure small diameter steel mains in coastal areas which have a high number of leaks and take samples from other sections for assessment;
- Inspect and repair 16.4 km of HDPE 575 mains in Albury and Wodonga which have been subject to hot and dry conditions, which is known to promote slow crack growth which has lead to gas escape in our South Australian distribution network;
- Conduct a HDPE 575 assessment with other Victorian gas distribution businesses, Deakin University and Future Fuels Cooperative research Centre (CRC) of 100 samples to test the life expectancy of these mains throughout Victoria based on their integrity and squeeze off points to inform the appropriate asset management approach for these assets in future AA periods;
- Replace 170 multi-user services which are susceptible to leaks, cannot be repaired and may cause interruption to supply for these multi-user sites; and
- Reactive replacement of 13,000 services that have failed in operation where repair is either not possible or economically viable.

This totals 3.5 km of targeted mains replacement forecast for the next AA period, which is a significantly reduced program compared to the 297 km forecast to be delivered in the current AA period.

We will also continue to reactively replace mains as issues arise, however we will capture this activity as opex, consistent with our approach in other networks.

9.5.2Growth

We extend our network and lay new reticulation mains, services and install meters to connect new customers to our network where it is economically and commercially viable. Customers continue to want to connect to the gas network and are expected to continue to do so over the next AA period. We are obligated to connect new customers in our network area when they request it and it is economically and commercially viable to do so.

Despite the longer-term uncertainty arising from the transition of the network from natural gas to renewable gas, continuing to connect customers today is beneficial as:

- Our network tariffs for all customers (new and existing) are lower than what they otherwise would be (i.e. than if we stopped connecting customer today), over the next AA period and beyond;
- Many appliances using gas have lower operating costs and are less carbon intensive;
- Continued growth will make the transition to renewable gas more cost efficient; and
- Gas networks are inherently reliable, with our customers on average experiencing unplanned outage once every 30 years.

Through our workshops our customers told us they consider gas as an essential service, especially for heating in the colder months in Victoria. Customers perceive gas as an essential service and believe that it plays a critical role in living comfortably every day as gas is vital to running family homes and businesses relying heavily on gas.

We therefore forecast to invest $240 million to connect around 69,000 new residential and business customers over the next AA period. This includes new homes and businesses in greenfield developments and in-fill developments across our northern and south-eastern metropolitan network, as well as a small number of existing homes and businesses connecting to our network for the first time.

9.5.3IT

We will invest $90 million in IT over the next AA period. This is an uplift compared to the $43 million we are forecast to spend in the current AA period.

The uplift is largely driven by a significant program of works required to transition and bring in-house a number of our core IT systems toward the end of the period. The forecast spend of $42 million on this transition includes a significant upgrade of our ERP system in line with our One AGIG IT Strategy.

We will invest $34 million over the period to maintain currency and deliver ongoing system improvements for our existing IT systems, uplift our cyber security capabilities (in light of new regulatory/legislative requirements and increasing cyber threats) and to replace end-of-life IT devices and infrastructure.

We are also proposing to invest $14 million to:

- improve information management;
- deliver an Asset Investment Planning and Management tool;
- support remote and digital metering; and
- provide a better and more accessible digital customer experience.

9.5.4Meter replacement

Customer meters measure the amount of gas delivered, which forms a key component of each gas bill. We undertake periodic meter changes to replace old meters and ensure meter accuracy is maintained. Based on the age and performance of our current fleet of meters, and the metering accuracy requirements we must achieve, we forecast to replace over 150,000 meters over the next AA period at a total cost of $35 million. This is broadly in line with what we are spending on periodic meter changes in the current AA period. We have used a consistent forecasting approach to determine the number of periodic meter changes required.

We will also replace around 3,600 hard to read meters with new meters that are read remotely. Initial selection criteria shall be customer meters that have not achieved a real read consistently over a period of more than 12 months.

At our customer workshops, customers raised smart and digital metering options as an area of interest. We went back to customers in the second phase of workshops with a summary of technical solutions available and potential costs of these. We then asked them to select from a series of statements so we could better understand the potential value of digital metering options for our

customers (and weigh this against the potential costs of solutions). We found the top three reasons for customer interest in digital metering were:

- They don't want estimated bills;
- They want to understand how much gas they are using every day;
- They want to make usage more efficient.

In our Multinet network, we have implemented a remote meter reading solution at a particular site which for heritage reasons has meters installed in areas which pose a significant safety risk to meter reading personnel. Due to these safety risks, these meters cannot be read every read-cycle. The goal of remote reading is to achieve a real-read every read-cycle. This will remove a significant number of estimated bills.

We propose to use remotely-read meters to achieve the same outcome for hard to read meters in the AGN network. This will remove a significant number of estimated bills which we know are a pain point for our customers.

While not part of our net capex, we will also look to offer an opt-in fee-for-service remotely reading solution for all customers. This would allow any customer to opt-in to a remote read metering solution by paying for the incremental cost of a new digital meter where they might not want meter readers on their property or find it difficult to be home to open locked gates for meter reading to occur. Complementary to this, we will explore more options for customers to submit self reads, which can be counted as actual reads for compliance purposes. We expect to be able to offer these solutions at no, or very little, additional shared fixed network cost to customers.

The remote read meters are also capable of storing usage information at more frequent intervals compared to our current two monthly manual reading cycle. Customers have told us they want to better understand how much gas they are using and therefore remote read meters provide an opportunity for us to explore the potential value of more detailed usage information being provided in customer bills.

Figure 9.4: Customer insights on digital metering priorities

Customers want to better understand and improve efficiency of their daily usage

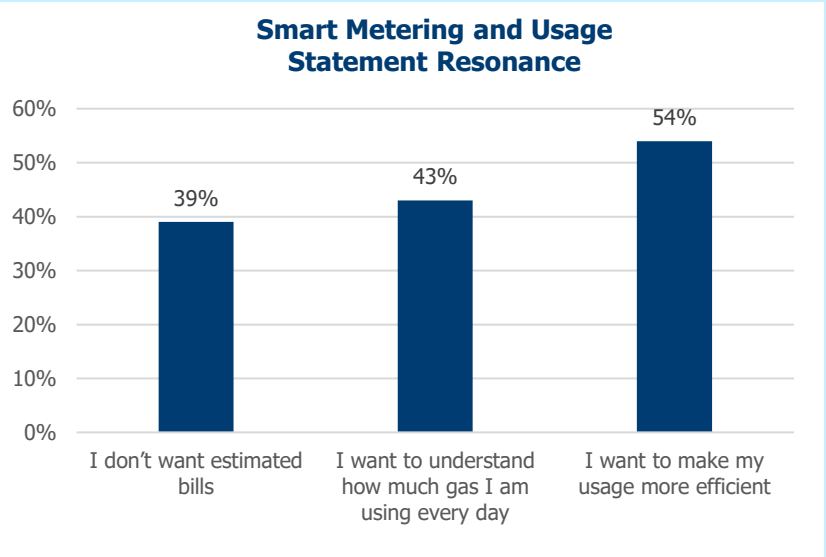
Customers value price visibility, transparency and the absence of bill spikes.

- Many customers cite gas prices being cheaper and more predictable than electricity, though electricity is easier to "monitor" usage
- Although price is a top priority, customers are adamant lower prices should not compromise safety or reliability

"Affordability needs to be balanced with safety and reliability, there is no point having it cheap if it's unsafe."

Customers want to better understand and improve efficiency of their daily usage.

- 39% of customers don't want estimated bills. Although a desire for real-time gas unsafe arose in Phase 1, some customers emphasise that having access to actual usage is more important than real time usage
- Customers want to feel empowered with usage information. CALD customers are particularly interested in their daily usage. In fact, 40% of AGN CALD customers rated it in their top 3
- More than half of customers value opportunities to make their usage more efficient



At the individual household level, gas consumption by appliance is likely to be pretty stable for ongoing daily uses such as hot water and cooking. The main variable for gas usage in Victoria is space and ducted heated, which is impacted by individual household heating requirements and weather. We aim to provide more information materials for our customers about typical usage and running costs for different appliances. We will also promote other information materials about how to improve the efficiency of household heating through draft proofing, insulation and other simple activities.

In section 9.5.7, we discuss our hydrogen network readiness activities. One of these activities is a trial of 1,000 digital meters for customers in Albury and Wodonga – where we are planning to blend 10% renewable hydrogen into the network. While this trial focuses on the use of digital meters for residential billing (which will be required for metering larger quantities of renewable hydrogen, compared to only natural gas or biomethane), it will also allow us to capture more information on the potential customer side benefits, such as reductions in usage, that might drive a case for a larger scale roll out of digital meters in the future.

9.5.5 Augmentation

We are always monitoring the pressure and performance of our network. We use this information to determine areas where our network is becoming constrained, which then requires augmentation or supply regulator capacity upgrades. Augmentation and upgrades of the supply regulators support the continued growth of the network and ensures service levels are maintained for existing customers in growing areas.

We are seeing continuing strong growth in the north and south of our network as well as in some regional areas in Wodonga, Traralgon and Echuca. We forecast over 15 augmentation projects will be required in the next AA period at a total cost of $70 million.

In the northern growth corridor we will undertake two augmentations in Wollert and four augmentations in Eltham to facilitate the growth in the network.

In the southern growth corridor, we will complete duplication of the Dandenong to Crib Point Pipeline and install seven augmentations in the Cranbourne and Clyde area.

We will also duplicate existing assets with new trunk mains in Wodonga, extend trunk mains to fringes in Traralgon and join new areas and lay new trunk mains in Echuca.

We will build one new regulating station in Wollert and three in the southern growth corridor to ensure we can support growth and maintain minimum operating pressures.

9.5.6 Telemetry

Telemetry allows for the monitoring and control of our network remotely through information captured from and transferred to assets in the field. In the next AA period, we will invest $4 million to replace end of life SCADA equipment, install additional pressure monitoring points to ensure we can continue to collect appropriate pressure information from the network as it grows and changes, and communications equipment to facilitate our remote meter reading solution and digital metering trial.

9.5.7 Other assets

We will invest $59 million on other distribution system assets. Two investments in the next AA period are:

- $16 million to complete modifications of our higher pressure transmission mains to allow inline inspection in accordance with accepted good industry practice, and
- $25 million to ensure the network is ready for the distribution of hydrogen which includes updating procedures, replacement of incompatible parts, further compatibility studies and a digital meter trial in the Albury/Wodonga region.

We will also continue integrity dig-ups and surveys, replace end-of-life regulators, valves and cathodic protection equipment and address other specific safety and integrity issues on our transmission pipelines such as slabbing in sensitive areas.

We will invest $8 million on other distribution system assets in the next AA period. This includes replacement of small plant and equipment based on the age and condition of these assets, as well as any changing business requirements, and refurbishment of our depot and office spaces as required.

Hydrogen readiness

Planning for the future is a key theme in this Draft Plan and has also been a key theme raised by customers and stakeholders through our engagement activities to date.

Figure 9.5: Our future plans

Phase 1 customer insights:

- We need to move towards cleaner energy supply to protect our planet and future generations
- 87% of customers view climate change and reducing emissions as important or very important

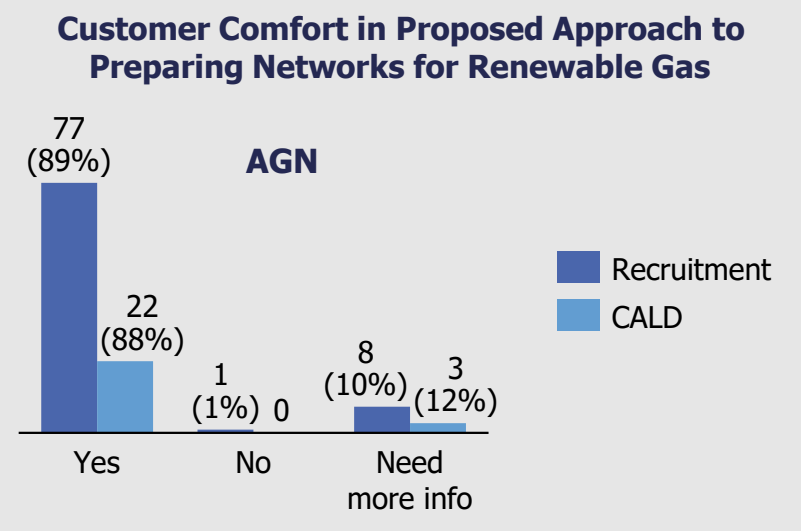
Our approach presented in Phase 2:

- Make sure our **network is ready for hydrogen blending**
- Continue to **grow the network** for the future
- **Communicate** more with customers on renewable gas
- **Ensure competitive pricing**, so that customers don't experience bill shock
- Invest in **renewable gas projects** (eg. Hydrogen Park Murray Valley) *with assistance of funding schemes eg. ARENA*
- Identify **no regrets actions** which may also assist the transition
- Set up an **Innovation Fund** – test new and innovative ideas and technologies

Phase 2 observations:

- Majority of customers consulted are comfortable with the proposed approach to preparing the networks for renewable gas.

"I'm comfortable with the plans but I think more investment could be made…We need to make sure there's a world around for future generations to come."



- The most commonly requested information is regarding transition plans such as upgrades to appliances, with emphasis that plans need to be communicated with the community.

"It would be good to know if there are new appliances available now suitable for future proofing."

Figure 9.5 summarises the future plans we presented in response to customer insights on the importance of decarbonisation.

In particular, and relevant to our capex investment in the next AA period, is:

- Make sure our **network is ready for hydrogen blending**; and
- Identify **no regrets actions** which may also assist the transition.

Concurrently with developing these plans, we have been working with the Australian Hydrogen Centre to deliver detailed feasibility studies of blending 10% renewable hydrogen into towns and cities, and ultimately a 100% renewable gas future. The draft findings of these studies have been used to inform no regrets actions we can take over the next AA period to assist the transition. To this end, we are proposing $25 million of investment in the next AA period to:

- replace incompatible parts such as axial flow regulators and some valves which use precipitation hardened and martensitic stainless steels ($10 million);
- bring sites up to a higher hazardous area classification standard ($7 million);
- implement revised in service welding procedures and reinforce existing welds where required and undertake hardness testing for a random sample of welds in each pipeline to show compliance with hardness limits ($4 million);
- modify billing systems to cater for midstream injection of renewable gases with different energy densities ($3 million);

- trial 1,000 digital meters for customers in Albury and Wodonga – where we are planning to blend 10% renewable hydrogen into the network. This trial focuses on the use of digital meters for billing, which will be required for metering larger quantities of renewable hydrogen, compared to only natural gas or biomethane ($0.3 million); and
- a further $0.8 million for capacity review of network regulating stations, transmission pipeline compatibility assessments, review of hazardous areas in our network and updates to a number of processes, procedures and work plans.

9.5.8 Escalation and overheads

Our total capex forecast for the next AA period also includes $3 million of real cost escalation and $21 million of capitalised overheads.

9.6 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 9.6 below.

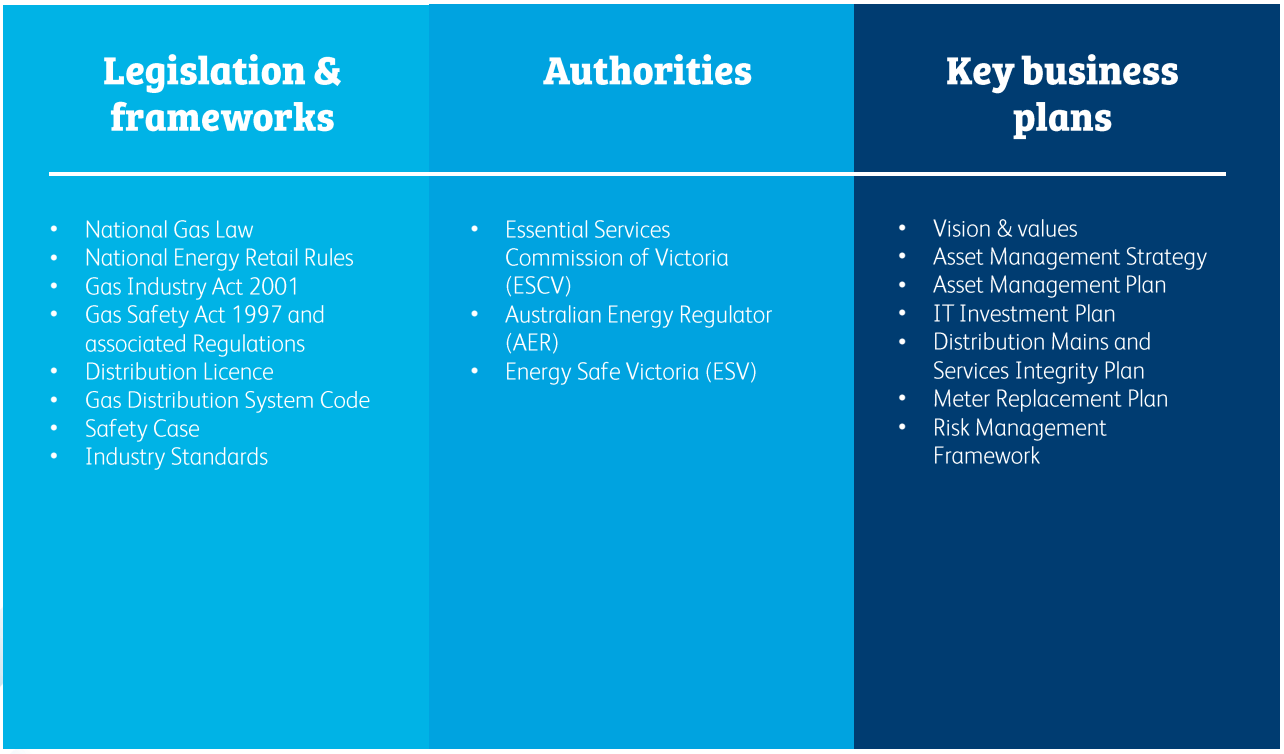
9.6.1 Key Business Plans

We have a number of key business plans that govern the scope, timing and approach to undertaking investment/upgrade of critical business information systems, asset replacement and augmentation works that 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 approved by Energy Safe Victoria (ESV) and the Essential Services Commission of Victoria (ESCV).

Our Safety Case is part of our overall approach to system management. It follows a continuous improvement cycle of Commit, Plan, Do, Check and Act, with the objectives of:

- maintaining a strong focus on safety and reliability in relation to the operation and management of our distribution network;
- ensuring suitable safety management systems are in place and operating to effectively manage and keep risks associated with the operation of our network to as low as reasonably practicable; and
- communicating relevant information related to the safe and reliable operation of our distribution network with our regulators.

Figure 9.6: Summary of our operating context



Our Asset Management Strategy (AMS) and Asset Management Plan (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;
- the Meter Replacement Plan which details our compliance obligations and how this drives the forecast volume of meters to be replaced over the next AA period; and
- Business Cases for other key assets categories which detail the drivers of other ongoing programs of work 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, reliable and safe operations of the network are maintained.

9.6.2 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 our capital delivery processes, this includes Executive Management Team review of key contracts before they are awarded.

We regularly report our expenditure performance against prior year spend 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 (other than in respect of some limited shipper funded works). This provides strong financial controls and governance in the delivery of capex.

9.7 Capex drivers in the current AA period

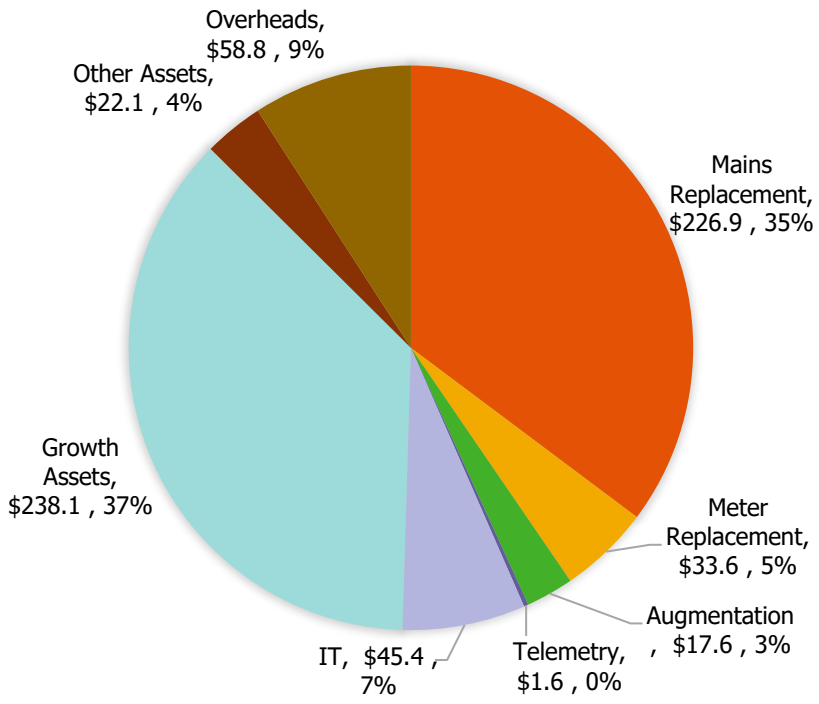
The following sections provide further detail on the capex drivers and activities we have undertaken in the current AA period.

9.7.1 Mains replacement

Our mains replacement program is the largest driver of our capex in the current AA period, and as outlined above will be a significantly reduced focus in the next AA period following completion of our low pressure mains replacement program. Completion of this program is the single most important activity we can undertake to ensure public safety.

In the current period, we will replace 297 km of old low

Figure 9.7: Capex by driver in the current AA period



pressure cast iron, medium pressure cast iron feeding the low pressure areas, unprotected steel and other mains. These low pressure mains were identified as representing a high and extreme risk to public safety. As agreed with our technical regulator, the ESV, we are on track to complete the replacement of all low pressure cast iron, unprotected steel and other mains, including all old CBD mains by the end of June 2023. This volume of activity is in line with our commitment to the AER in our last AA submission.

9.7.2Growth

In line with our vision of delivering profitable growth, we will invest $238 million to connect around 88,000 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 (infill), existing homes and businesses which are connecting to the gas network for the first time, and extensions of our network to the northern and eastern growth corridors as well as some regional areas in Victoria.

9.7.3IT

Our IT systems support a number of core business functions including billing, finance, asset management, asset operations, regulatory reporting and customer service.

In the current AA period we have invested a total of $45 million, which has been focused on nationalising and consolidating our major IT applications, leveraging the capability of these systems through our application renewal program and building our digital capability. This is below our approved allowance for the period as we:

- have been able to achieve a "current minus one" version methodology for our applications with less frequent upgrades than what we had initially planned;
- were able to leverage a shared Business Intelligence platform which means the infrastructure costs are spread over a larger base; and
- we have seen delays in some of our largest projects (GIS and Mobility).

While expenditure in relation to the GIS and Mobility projects has been delayed, we are planning to complete the full scope of works, at a lower cost than was approved, by the end of the current AA period.

9.7.4Meter replacement

We undertake periodic meter changes to replace older meters and ensure meter accuracy is maintained. Based on the age and performance of our current fleet of meters, and the metering accuracy requirements we must achieve, we have replaced around 129,000 meters to September 2021 and forecast we will have replaced a further 43,000 meters by the end of December 2022 at a total cost of $34 million over the five years.

9.7.5Augmentation

We augment our network to ensure we can support continued growth while also maintaining current service levels for existing customers in growing areas.

In the current AA period, we have invested $18 million in mains augmentations and capacity upgrades across ten projects. This includes augmentation in the northern and south eastern network to support growth in Doreen, Epping Wallan, Cranbourne and Clyde.

9.7.6Telemetry

In the current AA period, we will invest $2 million to replace end of life SCADA and pressure monitoring equipment to ensure we can continue to effectively control and monitor our network remotely through information captured from and transferred to our assets in the field.

9.7.7Other assets

We will invest $22 million on other assets in the current AA period. This includes completing integrity dig ups and surveys, replacing end-of-life regulators, valves and cathodic protection equipment, as well as other non-distribution system activities such as replacement of small plant and equipment based on the age and condition of these assets, as well as any changing business requirements.

9.7.8Overheads

We forecast a total of $59 million in capitalised overheads in the current AA period.

9.8 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;
- continue to provide the level of customer service that our customers require and expect; and

- support the transition of our gas distribution network to a decarbonised future.

The projects and programs we intend to deliver include:

- Continuing, albeit at a significantly reduced level, our mains replacement program. Specifically we will;
  - replace (3.5 km, $3 million) high pressure steel mains targeting some coastal areas;
  - inspect and repair 16.4 km of HDPE 575 mains that have been subject to over squeezing which can lead to slow crack growth and large gas escapes ($1 million);
  - replace 170 multi-service mains renewals which are experiencing integrity issues ($6 million); and
  - Reactive replacement of services that have failed and cannot be repaired ($13 million).
- Continuing our meter replacement program ($36 million) to ensure accurate gas measurement and billing for our customers and installing remote read meters for hard to read sites to reduce estimated meter reads, and personnel health and safety risk.
- Augmenting our networks ($71 million) to support the continued customer growth and maintain reliability
- Replacing end-of-life telemetry/SCADA equipment ($4 million) which is critical to operating and monitoring our network.
- Ensuring our IT systems are current and fit-for-purpose by maintaining and undertaking regular upgrades of our current applications ($34 million), upgrading our end of life ERP and transitioning other core systems ($42 million), and implementing new technologies for our business and our customers where there is a service improvement ($14 million).
- Connecting around 69,000 new residential and industrial customers to our network over the five years to June 2028 ($240 million).
- Modify our ageing transmission pipelines to allow for inline inspections where possible ($16 million) and other system works such as replacement of valves, pipeline slabbing and refurbishment of cased crossings ($4 million).
- Taking no regrets actions to support the network in the transition to renewable gases including replacement of incompatible parts, further compatibility studies, updating procedures and a digital ultrasonic residential meter trial in the Albury/Wodonga region ($25 million).

The completion of low pressure mains replacement in the current period drives a decrease in our forecast capex for the next AA period, with the introduction of some new areas such as remote metering, hydrogen readiness, digital customer experience and in-sourcing of a number of major systems partially offsetting this. The $544 million we will invest in the next AA period is $100 million (or 16%) below the forecast actual investment in the current AA period.

The projects and programs outlined will deliver the high levels of public safety and reliability valued by our customers and in line with our safety obligations, grow our network (ultimately leading to lower prices for all of our customers), assist the transition of our network to support the delivery of renewable gases over the next decade and ensure we continue to provide customer service that meets the expectations of our customers today.

10 Capital Base

This chapter discusses the movements in our capital base in the current and next AA periods.

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 seeking to change the rate at which we recover our capital base, to address the risks described in the Future of Gas (Chapter 6).**

We 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 will grow from around $1.9 billion to $2.3 billion over the next AA period.

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 (which services were explained in Chapter 7);
- 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.

Notably, the NGR allows (indeed requires) changes to the rate of depreciation to reflect the expected change in economic life driven by the decarbonisation of the energy sector, but in practice, this has been an area of little change in decades. This is no longer tenable given the pace of the energy transition and so we have accordingly adjusted depreciation in this Draft Plan.

10.2 Capital Base at 1 July 2023

We have adjusted (or rolled-forward) our capital base to 1 July 2023 with capex, inflation and forecast depreciation over the current AA period. We have used forecast information for 2021, 2022 and the first half of 2023.

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. 2017). Consistent with AER practice, the adjustment reflects the return recovered by AGN that otherwise would have occurred if actual information for 2017 were available.

Table 10.1: Roll Forward of the Capital Base 1 January 2018 to 30 June 2023 ($nominal, million)

	2018	2019	2020	2021	2022	1H 2023
Opening Capital Base	1,572.0	1,612.1	1,668.3	1,729.2	1,785.9	1,903.2
Less Depreciation	-77.9	-85.4	-95.6	-86.9	-94.3	-30.8
Plus Conforming Capex	87.7	108.1	129.9	149.7	142.9	61.2
Plus Actual Inflation	30.4	33.5	26.6	-6.0	68.7	34.6
Less 2017 Capex Adjustments	N/A	N/A	N/A	N/A	N/A	-19.6
Less Funding Adjustment	N/A	N/A	N/A	N/A	N/A	-5.4
Closing Value	**1,612.1**	**1,668.3**	**1,729.2**	**1,785.9**	**1,903.2**	**1943.3**

Note: Totals may not add due to rounding.

Table 10.2: Forecast Capex 2023/24 to 2027/28 ($2022/23, million)

	2023/24	2024/25	2025/26	2026/27	2027/28
Mains & Services	58.0	62.2	63.6	58.2	60.3
Meters	14.1	14.2	15.2	14.4	14.3
Buildings	-	-	-	-	-
SCADA	1.1	0.9	0.8	0.8	0.8
Computer Equipment	12.7	15.3	10.5	19.3	31.9
Other Assets	21.4	18.9	21.7	17.1	10.9
Closing Value	**107.3**	**111.6**	**111.8**	**109.9**	**118.3**

The closing value of the capital base forms the opening capital base for the next AA period.

We have also rolled forward the capital base for an additional 6 months to reflect the new start to the next AA period of 1 July 2023 (rather than the original date of 1 January 2023).

10.3 Capital Base as at 30 June 2028

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 Draft 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.

10.3.2 Forecast Depreciation

We have continued to apply the asset lives that were approved by the AER for the current AA period (as shown in Table 10.3). In determining forecast depreciation for the next AA period, we have applied the 'year-by-year' tracking approach. This approach is consistent with that used by the AER for other networks, including our AGN South Australia network.

The proposed depreciation in this Draft Plan also includes an amount to reflect the work undertaken as part of the Future of Gas Project (see Chapter 6).

and then to determine an amount of accelerated depreciation which would enable us to deal flexibly with the consequences of a range of scenarios.

In practical terms, we have brought forward $144 million ($2022/23) of depreciation from future years into the next AA period.

The AER has identified in their information paper "*Regulating gas pipelines under uncertainty*" that it is appropriate for regulated gas networks to assess the future asset stranding risk arising from the decarbonisation of the national energy supply over the coming decades, and then to

Table 10.4 shows our forecast straight-line depreciation, which includes the adjusted depreciation.

10.3.3 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 for actual inflation 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

Table 10.3: Summary of Lives Used to Calculate Depreciation

Asset Category	Standard Useful Life (years)
Mains & Services	60
Meters	15
Buildings	50
SCADA	15
Computer Equipment	5
Other Assets	15

Table 10.4: Forecast Straight-line Depreciation, 2023/24 to 2027/28 ($nominal, million)

	2023/24	2024/25	2025/26	2026/27	2027/28
Straight-line Depreciation	91.0	98.2	107.5	116.3	125.9

Our approach to depreciation is part of the outcome of work undertaken as part of the Future of Gas project, which is described in the Future of Gas Chapter of this Draft Plan. The intent of the Future of Gas project was to identify the potential asset stranding risk under four possible future decarbonised energy futures, ranging from full electrification to displacement of natural gas with renewable gas

apply potential remedies now which will mitigate that future risk but also provide for stable prices for customers over the long term.

We consider our approach meets this objective, and we will consult further on this issue and our proposed approach as we further develop our Final Plan for submission to the AER on 1 July 2022.

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

Table 10.5: Forecast Regulatory Depreciation, 2023/24 to 2027/28 ($nominal, million)

	2023/24	2024/25	2025/26	2026/27	2027/28
Straight-line Depreciation	91.0	98.2	107.5	116.3	125.9
Less Inflation	48.6	50.2	51.9	53.5	54.9
Regulatory Depreciation	**42.4**	**48.0**	**55.6**	**62.8**	**71.1**

Table 10.6: Forecast Capital Base, 2023/24 to 2027/28 ($nominal, million)

	2023/24	2024/25	2025/26	2026/27	2027/28
Opening Capital Base	1,943.3	2,008.8	2,075.8	2,138.3	2,194.4
Less Depreciation	-91.0	-98.2	-107.5	-116.3	-125.9
Plus Conforming Capex	107.9	115.0	118.1	118.9	131.4
Plus Actual Inflation	48.6	50.2	51.9	53.5	54.9
Closing Value	**2,008.8**	**2,075.8**	**2,138.3**	**2,194.4**	**2,254.7**

Note: Totals may not add due to rounding.

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).

The AER changed its approach to inflation in December 2020 to better reflect the way inflation operates within the context of the PTRM. We have followed this approach, and at present, it produces an estimate of 2.50%, which estimate will be updated for the Final Plan.

10.3.4 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.

10.3.5 Forecast Capital Base

The forecast capital base over the next AA period, taking into account forecast depreciation, capex and inflation, is set out in Table 10.6. This shows a closing capital base of $2,255 million as at 30 June 2028 in nominal dollar terms.

10.4 Summary

We have adjusted our capital base over the current and next AA periods to reflect actual/forecast capex, depreciation and inflation.

We have adjusted depreciation to reflect the uncertainty and risks our business is likely to face as the energy sector transitions to net zero. We have also applied the AER's approach to forecast inflation.

11 Financing Costs

Our single largest cost relates to the cost of financing our $1.9 billion investment in the AGN Victoria and Albury natural gas distribution network.

IN THIS CHAPTER:

- **The AER is currently in the process of updating the way it determines our allowed rate of return. We have followed the AER's 2018 Rate of Return Instrument to estimate the rate of return for this Draft Plan, but our Final Decision from the AER will incorporate the AER's 2022 Rate of Return Instrument, expected in December 2022.**
- **Based on forward market estimates, the rate of return is 4.2% (compared to 5.8% at the start of the current period).**
- **We are expecting lower financing costs in the next AA period, with the return on our investment estimated to fall by $100 million.**

In this Draft Plan, the allowed rate of return and the cost of tax have been calculated according to the AER's 2018 Rate of Return Instrument and the 2018 Tax Review.

Achieving a reasonable rate of return commensurate with efficient financing costs 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 NGR provides a framework for calculating the return on the projected capital base (rate of return). The AER's Rate of Return Instrument details the approach we are required to follow for calculating the rate of return under the NGR.

The instrument 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 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.

11.2.1 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 a "foundation model", which requires the following three parameters to be estimated:

- *The risk free rate* – Estimated based on the interest rate on Australian Commonwealth government bonds with a 10-year term;
- *Market risk premium (MRP)* – which reflects the expected return over the risk-free rate that investors require to invest in a well-diversified portfolio of risky assets; and
- *Equity beta* – which measures the sensitivity of a business' returns relative to movements in the overall market returns.

We have applied the AER's foundation model from the 2018 Rate of Return Instrument, which results in a return on equity of 4.95% over the next AA period (see Table 11.1).

These values are indicative and were measured using September 2021 information. We intend to use updated information in preparing our Final Plan.

Further, the AER is itself in the process of updating its 2018 Rate of Return Instrument, and will deliver a new Rate of Return instrument in December 2022.[18] This may result not only in changes to the parameters in the allowed return on equity, but also in the way in which this is calculated.

We do not yet know what the 2022 Rate of Return Instrument will contain, and will not know by the time of the Final Plan. However, the AER will apply this instrument in its Final Decision for AGN.

11.2.2 Return on Debt

Table 11.1: Indicative return on equity

Parameters	Value
Equity risk-free rate	1.29%
Beta	0.6
Market Risk Premium	6.10%
Return on equity	**4.95%**

The return on debt reflects the interest rate required by holders of our 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).

In the AER's 2018 Rate of Return Instrument, 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 (two-thirds weight) and BBB-rated debt indices (one third 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 2018 Rate of Return Instrument yields an average return on debt of 3.72%, which we have applied in this Draft Plan. As with the return on equity, the AER's approach to debt will be updated by the time of our Final Decision.

11.2.3 Rate of Return

In its 2018 Rate of Return Instrument, 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 (4.95%) and return on debt (3.72%) results in an overall average rate of return of 4.21% in the next AA period. As noted above, these figures will change with the making of the 2022 rate of Return Instrument.

11.3 Cost of Tax

We have reflected the outcomes of the AER's December 2018 Tax Review in this Draft 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 $3 million for each year of the next AA period.

11.3.1 Calculating the Cost of Tax

We have determined taxable revenue as total revenue less

[18] See https://www.aer.gov.au/publications/guidelines-schemes-models/rate-of-return-instrument-2022

Table 11.2: Roll forward of the tax asset base ($million, nominal)

	2023/24	2024/25	2025/26	2026/27	2027/28
Opening tax asset base	1,210.1	1,267.7	1,316.9	1,356.6	1,392.3
Plus gross capex	110.0	117.2	120.4	121.4	133.9
Less tax depreciation	-52.5	-68.0	-80.7	-85.6	-87.3
Closing tax asset base	**1,267.7**	**1,316.9**	**1,356.6**	**1,392.3**	**1,438.9**

opex, tax depreciation and interest expense; where:

- *Total revenue* – which is the sum of all of our costs (or building blocks) (see Chapter 14);
- *Opex* – which is a specific building block that is used to determine total revenue (see Chapters 8 and 12);
- *Tax depreciation* – which is based on the calculation of the tax asset base in any particular year; and
- *Interest expense* – which is determined by multiplying the cost of debt by 60% of our capital base in each year, reflecting the debt funded proportion of the total 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.

11.3.2 Value of Imputation Credits

The value of imputation credits (or gamma) is determined by calculating the product of:

- the proportion of imputation credits distributed (the distribution rate); and
- the value of the distributed credits to investors (theta).

The value of imputation credits (or gamma) is 0.585 as determined in the AER's 2018 Rate of Return Instrument. As with the return on equity and debt, this will be updated in the 2022 Rate of Return Instrument.

The effect of gamma is to reduce any tax allowance by 58.5%.

11.3.3 Tax Depreciation

Our approach to determining tax depreciation in this Plan has changed compared to our previous AAs.

This change is a result of the AER's Tax Review, in which the AER gave effect to three key changes:

- the use of maximum 20-year tax asset lives;
- the use of a diminishing value method (rather than a straight-line method) to calculate tax depreciation over those 20 years; and
- introducing the 'actuals informed approach' to the expensing of some forms of capex. The AER Tax Review recommended that networks reflect the approach they adopt in their financial tax asset base for regulatory purposes.

Table 11.3: Indicative AER Rate of Return and Gamma

Parameters	AGN Draft Plan
Return on Equity	4.95%
Return on Debt	3.72%
Overall Rate of Return	4.21%
Gamma	0.6

These changes, to the extent that they were not previously used by AGN, apply to new assets only, consistent with the expectations of the AER's 2018 Tax Review.

11.3.4 Tax Asset Base

The opening TAB of $1,210 million ($nominal) as at 1 July 2023 has been adjusted for the same forecast information used to adjust our capital base over the next AA period (see Table 11.2).

11.4 Summary

Our financing and tax costs collectively account for around 38% of our total costs. For the purposes of this Draft Plan, we have applied the AER's 2018 Rate of Return Instrument and the AER's Tax Review in determining our financing and tax costs.

This results in a rate of return of 4.21% (see Table 11.3) and a Net Tax Allowance of $15 million.

12 Incentives

We will continue to be incentivised to seek out efficiencies and maintain strong performance under the existing opex and capex schemes. We are also proposing a new Gas Network Innovation Scheme (GNIS) which we have developed with AusNet, Jemena, our customers and stakeholders.

IN THIS CHAPTER:

- **We are forecasting a total efficiency carryover of -$11 million in the next AA period from the operation of the opex efficiency benefit sharing scheme (EBSS) and capital efficiency sharing scheme (CESS).**
- **For the next AA period we propose to align the CESS with the AER's recent decisions for AGN South Australia and Jemena NSW by excluding new connections capex.**
- **We propose a new GNIS which will provide a more adaptable and fit-for-purpose funding mechanism (compared to expenditure allowances) for innovation projects, complementing and enhancing existing measures.**

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;
- balance incentives between opex and capex so that the most efficient expenditure mix is chosen;
- pursue efficiencies while improving or maintaining service quality; and
- encourage investment in innovation in areas that can provide longer-term benefits to our customers.

Our network currently operates under the opex efficiency benefit sharing scheme (EBSS) and the contingent capex efficiency sharing scheme (CESS), both of which we propose continue.

During customer workshops, our customers have told us they see innovation as an enabler to transition towards cleaner energy, and more affordable and safe gas supply. To provide a more adaptable and fit-for-purpose funding mechanism for innovation projects, we are proposing the introduction of a gas network innovation scheme (GNIS). The scope and form of the scheme we are proposing has been shaped by a joint engagement program with

AusNet, Jemena, our customers and stakeholders.

While we consider there is merit in the introduction of a customer service incentive scheme we have chosen not to pursue this because our customer satisfaction scores are improving without such a scheme.

The following sections provide further detail on regulatory requirements for the incentive schemes, the feedback our customers and stakeholders have provided and our proposed incentive schemes.

12.1 Regulatory Framework

A key objective of the regulatory framework is to promote efficient investment in, operation and use of gas distribution networks for the long-term interests of customers.

In keeping with this objective, the NGR provide for gas networks to have incentive schemes apply to encourage the efficient provision of services.[19]

The NGR also require 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.[20]

12.2 Customer and stakeholder engagement

Our customers expect us to get the basics right. This means an affordable, reliable and safe gas supply to their homes and businesses.

They are also focussed on the future and see innovation as an enabler to transition towards cleaner energy, and more affordable and safe gas supply.

A summary of customer insights on innovation are provided in Figure 12.1 below.

Innovation is an enabler to transition towards cleaner energy, and more affordable and safe gas supply.

Innovation is seen as fundamental to delivering a step change in ways of working and service delivery.

- Interest and support exists for innovation and investment in technology that reduces reliance on fossil fuels and increases sustainable practices.
- Innovation is also perceived an enabler for AGN/MGN's core factors of affordability (i.e. more efficient gas utilisation, cost efficiencies to pass on savings to customers) and safety/reliability (i.e. auto-leak detection technology, improved pipes).
- Many customers want comfort that technological advancements will not lead to a "loss of jobs".
- "Finding new and sustainable technologies and better ways to do things is very important.

Customers feel that AGN should leverage learnings from other countries to accelerate innovation and drive down cost.

- Sentiment exists that Australia is "far behind already" and that gas innovation is getting "left behind" relative to electricity.
- Some customers cite increased R&D investment as being required to "make sure targets are achieved", though many customers also emphasise the need for government support and partnering/learning from others in Australia and internationally to drive down cost.

19 NGR 98
20 NGL 24(3)

Table 12.1: Summary of revenue adjustments in the next AA period for incentive schemes operating in the current AA period

$m 2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	Total AA
Opex EBSS	4.8	0.6	(0.7)	(0.3)	0.0	4.5
Contingent CESS	(3.1)	(3.1)	(3.1)	(3.1)	(3.1)	(15.5)
Total	**0.7**	**(2.5)**	**(3.8)**	**(3.4)**	**(3.1)**	**(11.0)**

12.3 Current Period Performance

As noted above, our network is operating under the EBSS and Contingent CESS in the current AA period. We are forecasting a total efficiency carryover of -$11 million in the next AA period from the operation of these schemes (see Table 12.1).

Under the EBSS, we forecast a benefit of $5 million related to efficiency gains made in the current period. These are discussed in more detail in Chapter 8.

Under the contingent CESS we forecast a penalty of $16 million. The penalty under the CESS reflects that we will overspend our capex allowance in the current AA period by around $22 million (or 4%) and delayed compared to the allowance. This is discussed in more detail in Chapter 9.

The Asset Performance Index (API) which measures the relative health of our network compared to historic levels, and forms the contingent part of the CESS, is forecast to be 122.0. This reflects an increase in performance for average duration and frequency of service interruptions and mains and services leaks across our network over the current period. However, the asymmetric nature of the contingent CESS means we will incur 100% of the penalty in relation to the capex overspend.

12.4 Opex EBSS

Our network is currently subject to an opex EBSS and we are proposing to continue to employ this incentive scheme in the next AA period.

Further detail on how the EBSS works, where it applies and the benefits it has delivered our customers is provided below.

12.4.1 How the EBSS works

The EBSS is a key element of our opex forecasting approach (see section 8.4)[21] which is designed to provide 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 EBSS 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 are able to 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, the EBSS provides for 70% of the efficiency gains (or losses) to be passed through to our customers in the form of lower (higher) prices.

The revenue adjustment in the next AA period as a result of the EBSS (and efficiency gains achieved) in the current AA period is outlined in Chapter 14.

12.4.2 Where it is used

An opex incentive scheme has applied to our network for around 20 years, with the AER's opex EBSS in place for the last two AA periods. Over the two periods, we have achieved around $19 million in ongoing efficiency improvements, the benefits of which have been (or will be in the next AA period) passed through to our customers. We calculate the scheme, in its current form, has delivered $239 million in benefits to our customers since its introduction.

An opex EBSS is also in place on all other gas and electricity distribution and transmission networks regulated by the AER. In July 2019 Energy Networks Australia published *Rewarding Performance: How customers benefit from incentive-based regulation*, which calculated customer benefits in the order of $3 billion delivered through the

[21] Our opex forecasting approach relies on actual incurred opex in the penultimate year of an AA period being efficient.

operation of EBSS schemes applied to electricity and gas service providers in Australia between 2006 and 2018.

12.5 Capex CESS

The 'Contingent CESS' was introduced in Victoria for the current AA period following an extensive industry engagement program that included stakeholder representatives and gas distributors at a national level.

Further detail on how this CESS works and where it currently applies is provided below.

12.5.1 How the CESS works

In a similar manner to the EBSS, the CESS provides 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 increasing the incentive to incur efficient capex; and
- balances incentives that apply to decisions regarding whether opex or capex should be undertaken.

Under the Contingent CESS, 70% of any incremental capex efficiency gains (or losses) we achieve are passed on to our customers.[22][23] The scheme is asymmetric in that efficiency losses which result in a penalty for the business are passed on in full. Efficiency gains, however, are subject to two conditions which may reduce the reward for the business.

- Firstly, any efficiency gain is contingent on maintaining service standards and the health of the network, measured by the Asset Performance Index (API).
- Secondly, if the deferral of capex from one AA period to the next results in a material gain in the current AA period, but substantially higher costs in the next AA period, the efficiency gain may be 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.

12.5.2 Where it is used

As noted above, the 'Contingent CESS' was applied for the first time in gas to the Victorian distribution networks.

Since its application to Victoria gas networks, the contingent CESS has been further refined and now also applies to Jemena's NSW gas distribution network and AGN's South Australian distribution network. For Jemena and AGN SA, the 'Contingent CESS' was modified to exclude new connections capex as the volume of actual new connections was considered to be largely outside the control of the service provider, such that a service provider had limited scope to respond to the incentive.

In each case, some of the API measures differ to reflect specific network characteristics. A form of the CESS also applies to the electricity distribution and transmission networks regulated by the AER.

12.5.3 The 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.

We propose the same performance measures and the same approach to setting the targets as the AER applied for our network in 2018. 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 relatively share of our asset base.

The targets and weightings for each of these measures for the current period are shown in Table 12.2. We plan to update the targets and weightings for most recent actual performance (2017-2021) in our Final Plan.

[22] 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.
[23] These benefits and costs must be adjusted for any financing benefits or costs.

Table 12.2: Asset performance index measures, targets and weightings

	2018-22*	
Measure	Target	Weight
Unplanned SAIFI[24]	27.83	25%
Unplanned SAIDI[25]	3,388.67	25%
Mains leaks[26]	0.04	29.9%
Service leaks[27]	3.04	14.9%
Meter leaks[28]	18.96	5.2%

*set based on average actual performance achieved 2012-16

If we meet or exceed these targets, we can retain 30% of the efficiency benefit. However, if we do not meet these targets, the benefit can be reduced on a sliding scale, potentially to zero if we fall below 80% of the performance target. This provides customers with assurance that efficiency gains will not come at the cost of network performance or network health.

The sliding scale does not operate in the opposite direction (i.e. we do not receive a reduced financial penalty for any efficiency losses, even where there has been improved network performance). This asymmetric approach reflects the fact that customers are satisfied with the current safety and reliability performance they receive and may not be willing to pay more for further improvements.

12.6 Gas Network Innovation Scheme (GNIS)

Innovation on our network has the potential to promote the National Gas Objective by:

- promoting the efficient provision of services over the longer term; and/or
- enabling other customer objectives to be met (e.g. to meet emissions targets and/or to support renewable energy technologies).

However, the current regulatory framework makes it difficult to invest in innovation. This is because innovation most often results in increased expenditure in the short term and the payback period for innovation investment is often more than five years. This is in contrast to the EBSS and CESS, which provide incentives to reduce costs, with benefits and losses recovered over a five-year period. In the absence of an innovation scheme, there are reduced incentives to investment in innovation, particularly where the payback period on the investment is five or more years.

The GNIS provides a more adaptable and fit-for-purpose funding mechanism (compared to expenditure allowances) for innovation projects, to complement and enhance existing measures.

A GNIS would:

- Provide a continuous incentive to innovate through the regulatory period as the need for innovation emerges (much like current expenditure incentive schemes that encourage efficiencies to be revealed when they arise)
- Provide additional flexibility to deliver innovation, including to respond to requirements identified through previous innovation and customer feedback
- Encourage greater collaboration between stakeholders (business, research and customers) to work together to deliver innovation
- Require learnings to be shared with all stakeholders rather than being held by the business that delivers that innovation (resulting in improved efficiency).

12.6.1 Joint engagement on a GNIS

In our recent AGN SA review, we committed to continuing to engage with our customers and stakeholders including the AER, in partnership with Jemena Gas Networks and AusNet Services, to explore the merits of a GNIS.

The joint engagement on a GNIS was undertaken between September 2020 and November 2021 across two key phases to first understand levels of support, and if there was support, to co-design a potential scheme.

The engagement was supported by KPMG and a stakeholder reference group which included the other gas distribution businesses, the AER, Energy Networks Australia and Energy Consumers Australia.

In Phase 1 we found two-thirds of consumers and their

[24] Number of unplanned outages per 1,000 customers
[25] Number of minutes off supply per 1,000 customers
[26] Number of mains leaks per kilometre of main
[27] Number of service leak events per 1,000 customers
[28] Number of meter leak events per 1,000 customers

representatives were supportive of proceeding to Phase 2, to co-design a GNIS. Retailers were the least supportive cohort of stakeholders, taking overall support to 50%.

In Phase 2 we sought to:

- Collate, and where possible align, stakeholder views on the key design elements of a GNIS;
- Identify what information, activities or research would be required to develop a GNIS capable of acceptance by key stakeholders and the AER; and
- To demonstrate ongoing commitment to the Engagement Principles we agreed with stakeholders at the outset.[29]

We found consumers and consumer representatives viewed the draft principles as being reflective of the feedback provided in Phase 1 and good practice based on similar schemes nationally and internationally. They were also positive about the commitment to demonstrable customer benefit, customer input into assessment of projects, and transparent reporting.

Specific feedback from consumer stakeholders on the draft principles centred on the funding mechanism and ensuring appropriate reporting, governance and knowledge sharing.

Retailer representatives were not supportive of a GNIS, or incentive mechanisms for distributors in principle, expecting that GDBs should fund innovation as part of their regular expenditure.

In October 2021, we distributed a draft GNIS framework for consultation. Most feedback we received expressed comfort with the draft framework, however, retailers, continue not to support the introduction of a GNIS.

You can find more information on the GNIS engagement on our dedicated engagement website gasmatters.agig.com.au.

12.6.2 How the GNIS works

The GNIS provides a separate expenditure allowance which can be applied to innovation projects, sits outside of the EBSS and CESS and can be trued up at the end of the period (i.e. use it or lose it).

The proposed GNIS funding allowance has been the subject of network specific engagement. In AGN we are proposing total funding for the five years of the next AA period of approximately $5-7.5 million. This is equivalent to around $1.40-2 per customer per year. This is in line with the preferences of our customers (and less than 1% of our proposed total expenditure).

When accessing the funds, we will need to present eligible projects to a Joint Innovation Group which includes consumers and other stakeholders who are able to provide recommendations to decisions. To be eligible, projects must be:

- Innovative – which means based on new or original concepts or involves technology or a technique not previously implemented in the distribution of gas and in the form of a trial, development or demonstration;
- Likely to result in customer benefits through price, quality or reliability;
- Have an expected payback period of 6-15 years; and
- Not be eligible for funding under other state or federal government schemes.

Program-level reporting across all GNIS funded projects will be undertaken, with emphasis on ongoing reporting and engagement, as well as collaboration and knowledge sharing across the industry.

Any GNIS funds not spent during the period will not roll over and will be returned to customers in the subsequent AA period.

12.6.3 Where it is used

Similar types of schemes to the GNIS exist in Australia and internationally.

The AER's electricity demand management innovation incentive scheme innovation allowance mechanism was introduced in 2017 to provide electricity distribution businesses with an incentive to undertake efficient expenditure on non-network options relating to demand management and to provide distribution businesses with funding for research and development in demand management projects that have the potential to reduce long term network costs.

More recently, the AER approved AusNet's customer-led innovation proposal for its electricity distribution network in Victoria.

Internationally, mature innovation schemes exist for gas network businesses in the UK, Ireland, France and California. While these schemes are funded through gas network prices, many of them are open to all potential participants

[29] The Engagement Principles we agreed with stakeholders were to be genuine and committed, to integrate their feedback, provide clear, accurate and timely information, to be accessible and inclusive, and to be transparent and measurable.

including research institutions and other gas market participants.

12.7 Customer service incentive scheme

We are not proposing the introduction of a Customer Service Incentive Scheme (CSIS) for the next AA period. We note that our customer satisfaction scores, which we have been measuring since 2018, continue to improve, reflecting our ongoing focus on our customers. We therefore do not consider that a CSIS is required for the next AA period.

We have committed to achieve customer satisfaction scores of at least 8.2 out of 10 in the next AA period (see Chapter 4).

12.8 Summary

In the next AA period we are proposing to maintain the incentives in place through the existing EBSS and CESS to pursue ongoing efficiencies and to share the benefits of these with our customers.

We are also proposing to introduce the GNIS, the scope and form of which has been developed through ongoing consultation with our customers and stakeholders, the AER, and the wider industry over the past year.

13 Demand Forecasts

Customers will continue to connect to the network, reflecting customer demand for natural gas in their homes and businesses. The average gas use of our residential customers is however expected to decline resulting in an overall decline in demand for gas on the network.

IN THIS CHAPTER:

- **Our demand forecasts have been independently determined applying methodologies consistent with those approved previously by the AER, and reflect government policy in support of decarbonisation of the energy supply in Victoria.**
- **Overall demand for gas in the residential and industrial sectors is expected to fall whilst demand in the commercial sector is expected to rise.**

The demand for our services drives our operations and is a determinant of our prices.

Our forecasts of natural gas demand and customer numbers are 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 and Resources ('Core Energy'), for our:

- residential customers;
- commercial customers (business customers who use less than 10 terajoules of gas each year); and
- industrial customers (our largest business customers who consume more than 10 terajoules of gas each year).

In the next Access Arrangement (AA) period, Core Energy forecasts the demand for natural gas for our:

- residential segment to fall by 1.5% per year, in response to a range of external factors, such as State and Federal government policy initiatives, higher projected wholesale gas prices, improved appliance and dwelling efficiency and lower new dwellings growth;
- commercial customers to increase by 1.8% per year, largely in line with trends in consumption per connection; and
- industrial customers to fall by 2.0% per year, in response to higher wholesale gas prices, decarbonisation and technological advancement.

Overall, Core Energy projects that the demand for gas by our customers will fall by 1.1% per year in the next AA period.

The following sections provide 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 2013 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 has assessed Core Energy's forecasts against these principles and concluded that their forecasts were consistent with them.

13.2 Regulating gas pipelines under uncertainty

The AER released its information paper *Regulating gas pipelines under uncertainty* in November 2021. The paper outlines the challenges facing the gas sector including the increasing uncertainty of the future gas demand driven by the decarbonisation policies of both State and Federal Governments, the competitiveness of renewable electricity, improvements in energy efficiency, changes in consumer sentiment towards gas and an uncertain outlook for future wholesale gas prices.

The AER examined the uncertainty in relation to future gas demand and explained that it expected regulated networks to:

- take into account relevant climate change policies and cross-elasticities of demand for natural gas substitutes in their demand forecasts;
- forecast a range of different possible demand scenarios, with associated probabilities;
- look well beyond the next regulatory period, and consider demand and supply conditions potentially several regulatory periods into the future; and
- form a view on whether or not current price levels will be able to be maintained in the future, in the face of different demand scenarios.

13.3 Stakeholder engagement

We have engaged with our stakeholders in respect of our demand forecasts. At our joint Victorian Gas Networks Stakeholder Roundtable (VGNSR) and Retailer Reference Group (RRG) meetings and through our large user survey, we discussed the forecasting approach and the importance of understanding key drivers of future demand.

Stakeholders indicated they understood our approach to forecasting residential, commercial and industrial demand.

Stakeholders acknowledged the decarbonisation journey we need to take to satisfy both our customers' expectations and our vision to be environmentally responsible. Stakeholders acknowledged they were comfortable with the approach to forecasting demand, including taking account of decarbonisation policies which will affect future demand.

13.4 Residential and Commercial Demand

The methodology that Core Energy has used to forecast demand 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 is therefore discussed jointly below.

13.4.1 How our forecasts were developed

The methodology Core Energy has used to forecast our residential and commercial customers' demand is summarised in Figure 12.1.

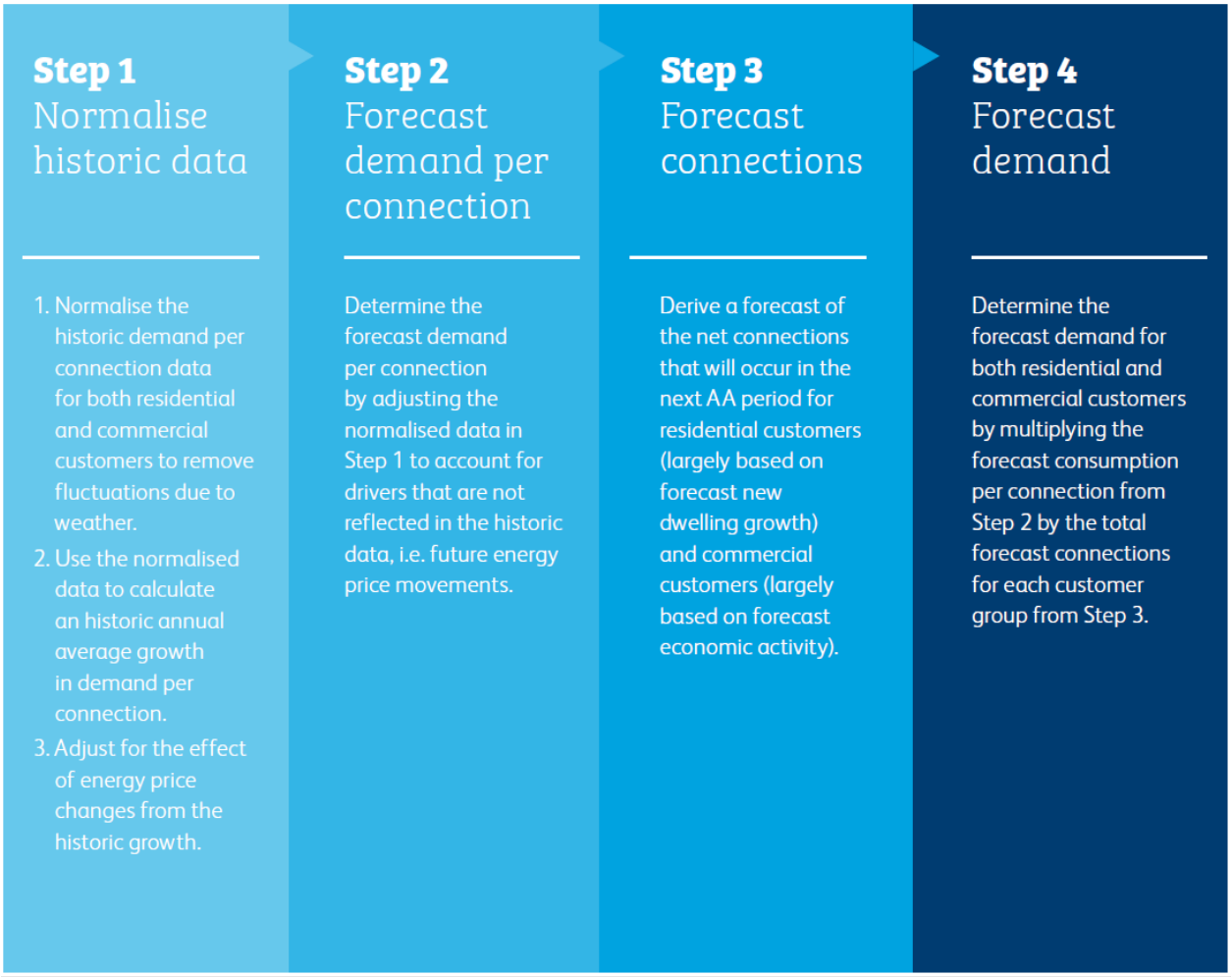
The methodology is consistent with the approach that was used to develop the demand forecasts for the current AA period for our South Australia and Victoria and Albury networks, which were approved by the AER. It is also consistent with the principles employed by the Australian Energy Market Operator (AEMO), when forecasting residential and small commercial demand for its Gas Statement of Opportunities.

Further detail on some of the key elements of Core Energy's 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.

Figure 13.1: Forecasting method used for residential and commercial customers



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) 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.

Energy prices

In addition to weather, our residential and commercial customers' demand for gas is affected by changes in retail gas and electricity prices. An adjustment must therefore be made to the historic growth in consumption per connection to remove these effects (see Step 1.3 in Figure 13.1).

In the ordinary course, an adjustment is then made to the forecast demand per connection to reflect the forecast movement in retail gas and electricity prices.

To incorporate the effect of these prices on both the historic data and forecast demand for gas, estimates are normally required of:

- the responsiveness of gas demand to a change in retail gas prices (referred to as 'own price elasticity'); and
- the responsiveness of gas demand to retail electricity prices (referred to as 'cross price elasticity').

Due to the additional factors that have been taken into account in deriving this forecast, for instance the impact of both Federal and State Government Policy and COVID-19, and the consequential impacts to gas demand, Core Energy has concluded it not

appropriate to apply elasticities to its forecast in this instance. This approach will be subject to further review before we submit our Final Plan.

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 the AGN Victoria and Albury network areas.

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 an increase in new dwelling commencements, particularly multi-unit dwellings over the course of the next AA period. Total Victorian commencements are projected to increase from approximately 44,500 dwellings in 2023/24 to 57,700 dwellings in 2027/28, with AGN Victoria and Albury assumed to capture a 27% share.

Multi-unit dwellings are the key driver of this increase with 8,500 additional multi-unit dwellings and 4,700 detached dwellings over the AA period.

Albury's connections are based on the historic trend with net connections forecast to increase by approximately 1,700 over the course of the AA period.

COVID-19

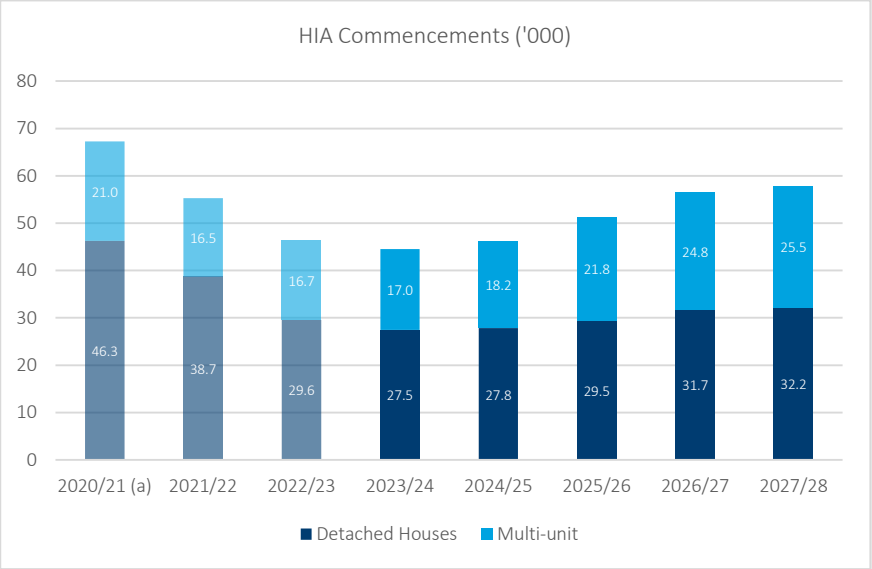
Victoria's COVID-19 lockdowns persisted throughout much of 2020 and 2021 and had different impacts on the residential and commercial sectors.

Residential customers who stayed at home rather than attending their workplaces during business hours required more heating than usual during the cooler months of 2020 and 2021 because they were often at home rather than their workplaces. Residential gas demand in 2020 was 9.0% higher than in 2019. Demand was also driven higher by the colder weather in 2020. Even when normalising for weather, it is clear that COVID-19 lockdowns increased residential demand.

Conversely, gas demand in the commercial segment was negatively impacted due to restrictions on businesses trading during lockdown. This drove Commercial demand 13.0% lower in 2020 (despite the colder weather).

Core Energy has adjusted for the effects of COVID-19 by excluding demand data since the beginning of FY20 from the consumption trend.

Figure 13.2: HIA Forecast of new dwelling commencements



13.4.2 Residential demand forecast

Using the methodology set out above, Core Energy has developed its 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 (net of forecast disconnections) will grow by 1.5% per year in the next AA period, reaching 789,034 by the end of the period (see Figure 13.3).

The forecast of new connections is driven by HIA's forecast of new dwellings. The HIA has formed the view that in the medium term, the COVID-19 pandemic will have a material impact on the drivers for housing demand, including density, location and type of housing. The HIA sees a shift away from construction in large cities such as Sydney and Melbourne in favour of regional areas, which has reduced the level of construction activity expected during the AA period.

Some stakeholders have queried why it is prudent to continue to connect new customers in the context of the decarbonisation of the energy sector. We continue to observe interest in new connections and penetration rates. We expect this to continue in the next AA period. Connecting new customers to our network spreads our largely fixed cost base over a larger number of customers, which helps us to continue to deliver energy at a competitive prices and is also important to enable an effective planned transition to renewable gas.

Figure 13.3: Residential connections forecast (no.)

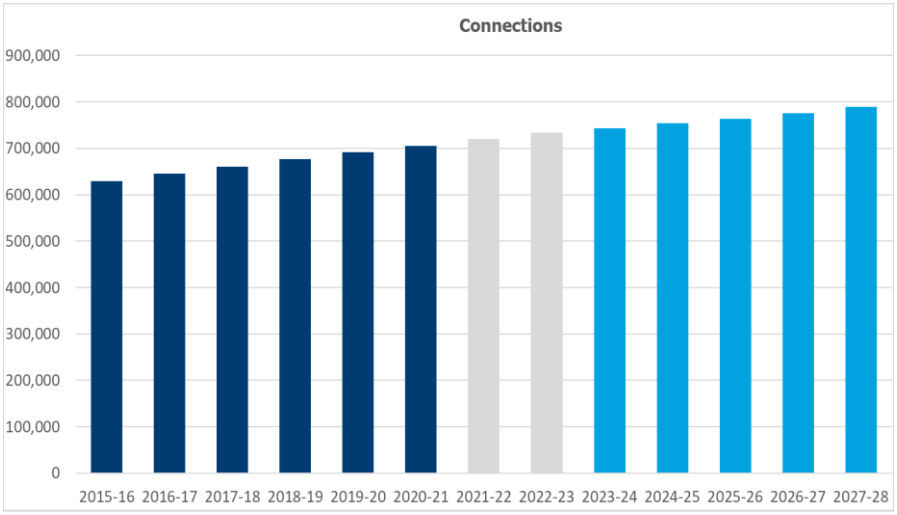


Figure 13.4: Residential Consumption per Connection (GJ)

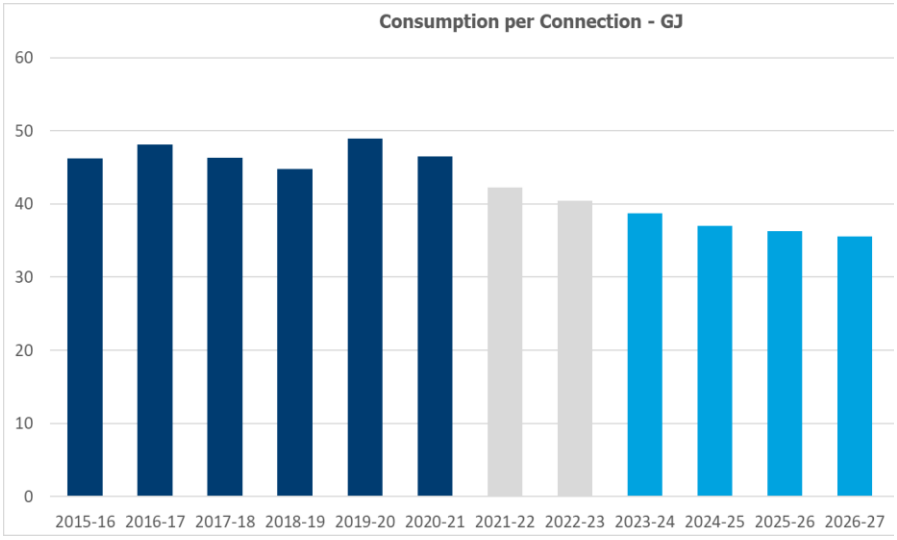
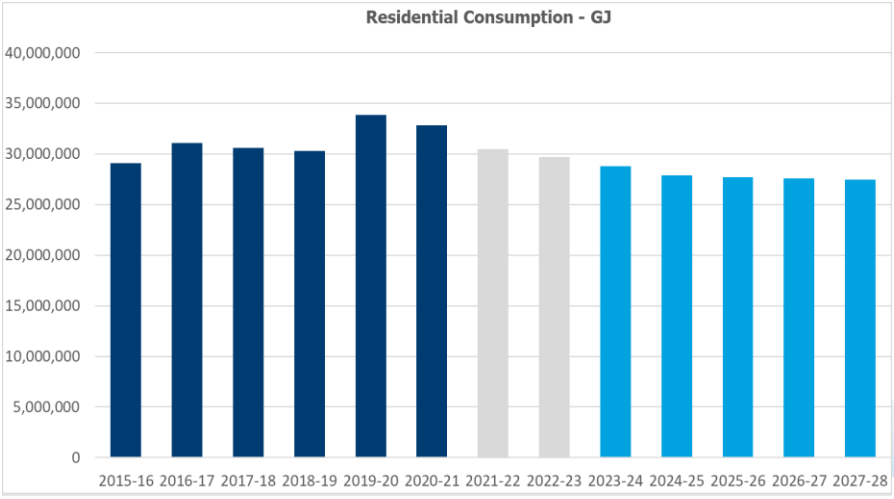


Figure 13.5: Total Demand (GJ)



Consumption per connection

Core Energy is also projecting that consumption per residential connection will fall by around 2.9% per annum over the next AA period, from 38.7 GJ in 2023/24 to 34.8 GJ in 2027/28.

The key drivers of this decline include improved appliance and dwelling efficiency driven by both technological improvement, Victorian Government policy and higher expected wholesale gas prices over the AA period. This drives the substitution of gas appliances for their electric equivalent (for example, substituting gas heating for electric reverse cycle air-conditioning).

The Victorian Government's *Gas Substitution Roadmap* consultation paper examines pathways towards net zero emissions by 2050 in Victoria. Significant funding of around $1.6 billion has been earmarked to accelerate the transition to clean energy including to:

- improve the energy efficiency of 250,000 low income homes;
- improve the thermal performance and replace inefficient appliances;
- fund battery subsidies; and
- provide grants to large industrial energy users to introduce energy efficiency and demand management.

The Roadmap may impact on our demand forecast. We will review the release of the roadmap in early 2022 and incorporate it into our Final Plan to the extent required.

The trend in consumption per connection has been affected by the COVID-19 lockdowns in Victoria throughout 2020 and 2021. The effect of these lockdowns has been that residential customers who would otherwise have physically attended their worksites before the pandemic instead worked at home during the lockdown periods.

During the colder months in Victoria, more customers at home meant a higher utilisation of space heating and potentially a higher prevalence of cooking at home. This increased gas demand in 2020 and 2021 and has therefore been excluded from the trend. This approach is consistent with the approach accepted by the AER in its Final Decision for our South Australian natural gas distribution network where natural gas demand was also affected by COVID.

Total residential demand

In addition to COVID impacts, the nearer term objectives of the Gas Substitution Roadmap include the reduction of carbon emissions relative to 2005 levels of between 28% - 33% by 2025 and 45% to 50% by 2030.

The Victorian Government expects this combination of initiatives to reduce gas consumption in Victoria by nine percent by 2025[30], which falls in the second year of the next Access Arrangement period.

Given the Victorian Government's policies to improve insulation, subsidise replacement of inefficient gas appliances and strong support for full electrification from some quarters, there are strong headwinds to future natural gas demand with potentially lower connections growth and a higher level of disconnections on our network.

Natural gas is on its own decarbonisation journey through the gradual blending of renewable gas into our networks. The term 'renewable gas' refers to both hydrogen and biogas and is a carbon-free alternative to natural gas. There is further discussion on the decarbonisation of natural gas and what it means for our networks in Chapter 9.

Overall, the demand for gas by our residential customers in the next AA period is expected to fall by 1.5% per year from 28,769TJ in 2023/24 to 27,485TJ in 2027/28 (see Figure 13.5 and Table 13.1). We still expect residential gas demand to remain high in Victoria and far higher than in any other state.

[30] https://www.victorianenergysaver.vic.gov.au/save-energy-and-money/victorian-energy-upgrades

13.4.3 Commercial demand forecast

Like residential demand, Core Energy's commercial demand forecast is calculated by multiplying the forecast number of commercial connections by 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 0.5% per year, which is in line with the 10-year historic growth rate of 0.5%.

Consumption per connection

The average consumption per commercial connection is expected to increase over the next AA period reflecting the long-term trend (see Figure 13.7).

The lockdowns in Melbourne due to COVID-19 reduced consumption in the Commercial segment during 2020 and 2021 because many businesses were forced to shut down, either temporarily or permanently.

As with the residential forecast, COVID-19 distorted gas demand and hence those years affected by the pandemic have been excluded from the trend.

Consumption per commercial customer is forecast to increase by 1.3% per year over the next AA period from 339 GJ in 2023/24 to 357 GJ in 2027/28.

Total Commercial demand

The total demand for gas from commercial customers is expected to grow by 1.8% per year over the next AA period, from 8,618TJ in 2021/22 to

Figure 13.6: Commercial connections forecast

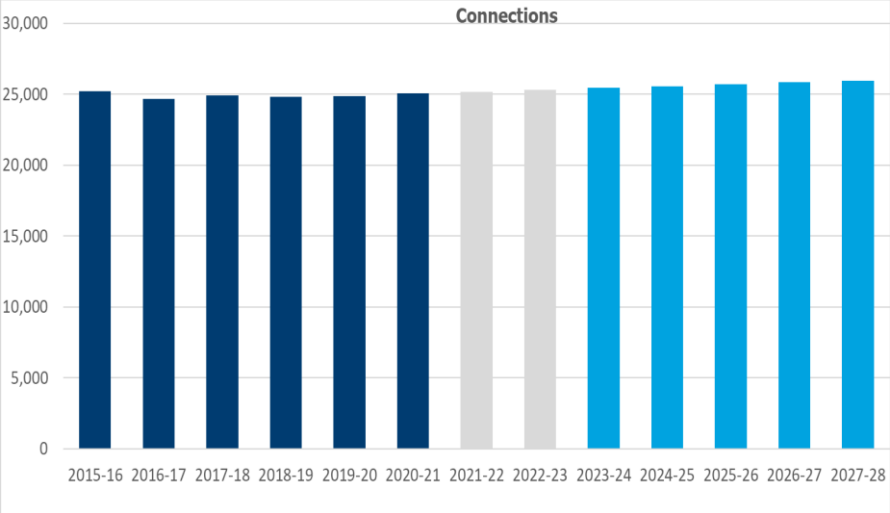


Figure 13.7: Commercial Consumption per Connection

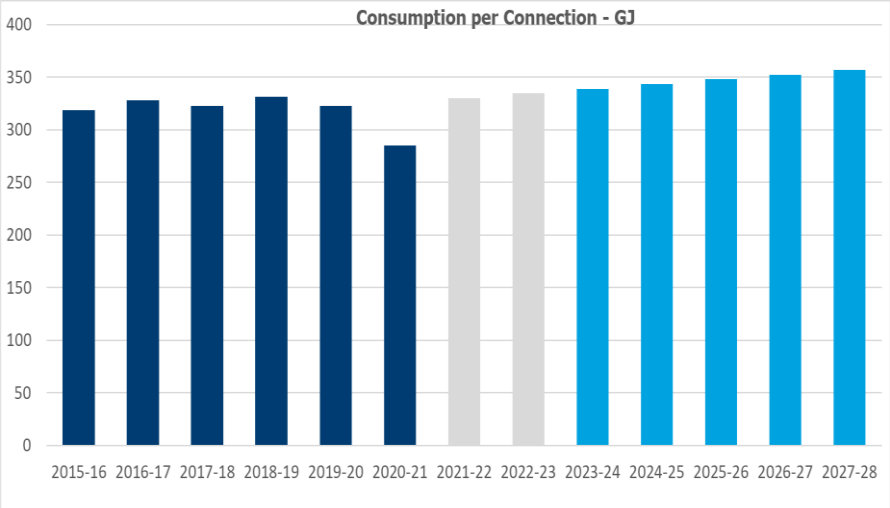
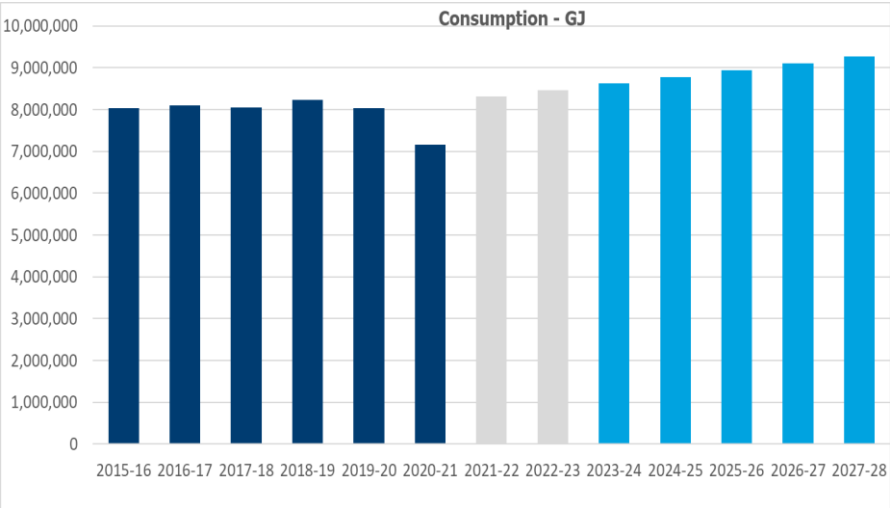


Figure 13.8: Total Demand



9,266TJ in 2025/26 (see Figure 13.8).

13.5 Industrial demand

13.5.1 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 in an hour. The forecast demand for this group is therefore based on both:

- the maximum amount of capacity that our industrial customers are expected to require in an hour (referred to as Maximum Hourly Quantity (MHQ)); and
- the total amount of gas that our industrial customers are expected to consume in a year (referred to as Annual Contract Quantities (ACQ)).

To help inform this forecast, we conducted a survey of our top 50 industrial customers, the objective of which was to better understand their future MHQ and ACQ requirements, including any planned connections or disconnections over the next AA period. One customer responded to the survey.

For those customers that did not respond to the survey, Core Energy examined the relationship between each customer's historic demand and economic activity. In those cases where there was a statistically significant relationship, the MHQ and ACQ was 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 MHQ and ACQ were forecast by applying an adjustment based on the historic trend.

Figure 13.9: Industrial Connections

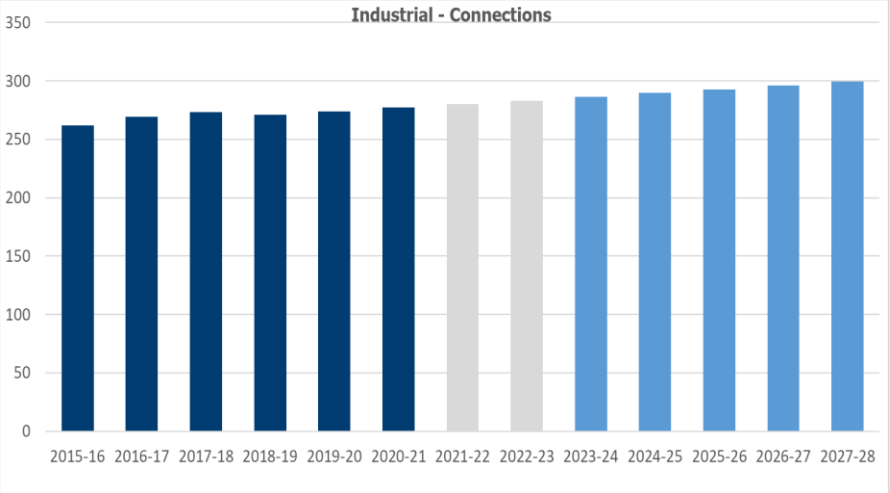
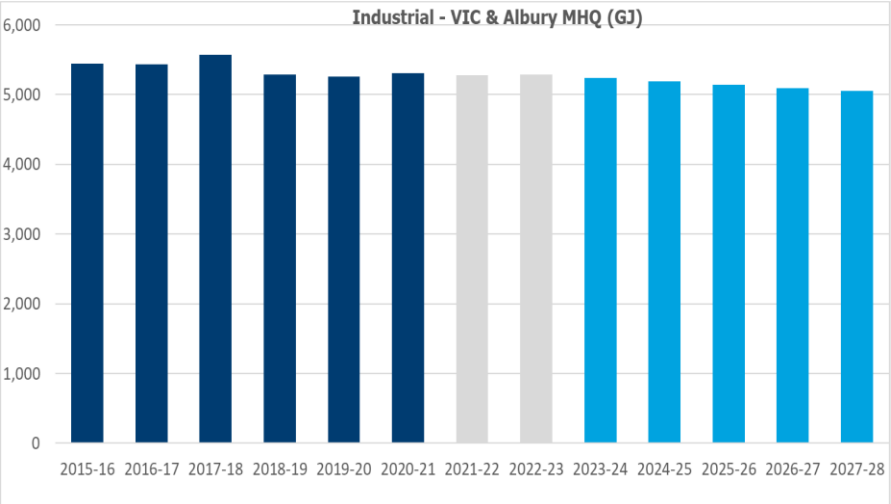


Figure 13.10: Industrial MHQ



For those industrial customers in sectors of the economy which are affected by weather, the historic trend was adjusted for the impact of weather.

The connections forecast for industrial customers has been developed having regard to historic growth estimates and information on known new connections and disconnections.

13.5.2 Industrial demand forecast

Industrial MHQ is forecast to decline by 0.9% per annum to 5,049 GJ MHQ over the next AA period (see Figure 12.9).

Industrial connections are forecast to rise to 299 connections, from 283 at the start of the AA period (see Figure 13.10).

13.6 Summary

Table 13.1 provides a summary of our demand forecasts for the next AA period.

As this table shows, residential and industrial demand is forecast to decline over the next AA period whilst commercial demand is forecast to rise.

Our demand forecasts are based on the methodology accepted by the AER in the current AA period for both our South Australian, Victorian and Albury networks, with adjustments reflecting the AER's expectations outlined in its information paper *Regulating Gas Pipelines Under Uncertainty*.

Table 13.1: Summary of demand forecast

	2023/24	2024/25	2025/26	2026/27	2027/28
Residential demand					
Connections (no.)	743,743	753,740	764,165	775,912	788034
Consumption per connection (GJ)	38.7	37.0	36.2	35.5	34.8
Demand (TJ)	**28,769**	**27,863**	**27,697**	**27,571**	**27,485**
Commercial demand					
Connections (no.)	25,440	25,569	26,699	25,829	25,960
Consumption per connection (GJ)	338.7	343.2	347.7	352.3	356.9
Demand (TJ)	**8,618**	**8,776**	**8,937**	**9,100**	**9,266**
Industrial Demand					
Connections (no.)	286	290	293	296	299
MHQ (GJ)	5,241	5,192	5,144	5,096	5,049

14 Revenue and Pricing

This chapter sets out the total revenue and the proposed prices to apply over the next AA period.

IN THIS CHAPTER:

- **We have proposed to cut Victoria and Albury network prices by 8% after the impact of inflation on 1 July 2023.**
- **This will save the average residential customer $22 per year, commercial customer $76 per year and industrial customer $1,900 per year. Affordability of gas is a also a strong consideration for our business, particularly in light of the uncertain use of gas in a low carbon energy system. It is very important that the cost of gas is cost competitive for our customers.**
- **Our proposed price path reflects the forecast growth of our capital base which will enable revenue growth commensurate with changes in our underlying costs.**

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 Benefit Sharing Scheme – EBSS) or the capex incentive mechanism (Capital Efficiency Benefit Sharing Scheme – CESS).

Our prices are required to reflect, to the extent possible, the underlying cost of providing services to our customers.

14.2 Stakeholder engagement

Customers and stakeholders told us that affordability is their highest priority. In developing this Draft Plan we have had regard for the impact individual aspects of the plan will have on the affordability of natural gas.

As part of our engagement on this Draft Plan, we will also seek feedback on our pricing structure, specifically in relation to our proposed price path. This feedback will be reflected in our Final Plan submitted to the AER by 1 July 2022.

14.3 Revenue

This Draft 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 14.1.

Our building block revenue is recovered through the prices we charge retailers for providing residential, commercial and industrial haulage services and Ancillary Reference Services. We are required to set our prices such that the total revenue we recover, which is the sum of tariff revenue (referred to as smoothed revenue) and ARS revenue equals 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 14.2. The price cut in the first year of the AA period followed by no price changes thereafter reflects our engagement with our customers and stakeholders to date. In the early stages of an AA proposal, we engage on a simple upfront price change with no changes thereafter because it is easier for our customers and stakeholders to understand and compare.

As we have done in previous reviews, for the purposes of the Final Plan, we will develop a price path that:

- provides for revenue growth that approximates the growth in the capital base over the next AA period to ensure the growth in our revenue is commensurate with changes in our underlying costs; and
- equates revenue (or building block revenue) with our underlying costs recovered through the prices we charge retailers in 2027-28 (the last year of the next AA period) to ensure that there is no one-off adjustment to prices (either positive or negative) required from 1 July 2028 to equate smoothed revenue with costs.

Table 14.1: Building Block Total Revenue, 2023/24 to 2027/28 ($nominal, million)

	2023/24	2024/25	2025/26	2026/27	2027/28
Return on Capital	85.4	86.4	87.4	88.0	88.2
Return of Capital	42.4	48.0	55.6	62.8	71.1
Opex	92.4	96.1	97.8	102.8	106.6
Incentive Mechanism	-2.3	-6.7	-8.3	-8.0	-7.9
Cost of Tax	3.9	2.7	2.1	2.6	3.7
Building Block Total Revenue (including ARS)	**221.9**	**226.5**	**234.6**	**248.2**	**261.7**
Less ARS	4.2	4.3	4.4	4.6	4.7
Building Block Total Revenue (excluding ARS)	**217.7**	**222.2**	**230.2**	**243.6**	**256.9**

Note: Totals may not add due to rounding

Table 14.2: Proposed Price Path, 2023/24 to 2027/28 ($nominal, million)

	2023/24	2024/25	2025/26	2026/27	2027/28
Building Block Total Revenue (excluding ARS)	217.7	222.2	230.2	243.6	256.9
Smoothed Revenue	225.4	226.9	232.6	238.6	245.2
Real Price Path	10.9%	0.0%	0.0%	0.0%	0.0%

By aligning our price path to the growth in our capital base we are more likely to sustain stable credit metrics at levels assumed by the AER in setting the return on debt. This is because our revenue will more closely match our underlying costs over time (see Section 14.3.1). We will engage with stakeholders on this issue and reflect the outcomes of this engagement in the Final Plan.

14.3.1 Financeability

The AER assumes a weighted average credit rating between A- and BBB+ when it sets the return on debt (as the assumed credit rating directly impacts borrowing costs). We therefore consider it is good regulatory practice to consider whether our proposal meets the credit metrics required of A-/BBB+ rated business.

The ratings agencies focus on the following two key credit metrics in determining a credit rating for a business:

- Funds from Operations (FFO) to debt – which is defined as FFO divided by debt (and which measures the availability of cash flow to repay the balance of outstanding debt); and
- FFO to interest – which is defined as FFO plus interest divided by interest (and which measures the availability of cash flow to pay interest costs).

FFO is calculated as total smoothed revenue less interest, opex and tax. Our conservative view is that the ratings agencies require a sustained FFO to debt ratio of at least 9% and a FFO to interest ratio above 2.5 to determine a weighted average credit rating of between A- and BBB+. We also consider that the key focus of the credit rating agencies is on the FFO to debt ratio given the prevailing very low interest rate environment (making interest coverage a far easier constraint to achieve).

We have assessed the key credit ratios delivered by our Draft Plan (see Table 14.3). Our Draft Plan delivers an average FFO to debt of 7.1% and FFO to interest of 2.9 over the next AA period. The FFO to Debt is lower than the 9% threshold required for a weighted average A-/BBB+ rating required by ratings agencies whilst the FFO to Interest Cover is above the threshold.

When making its Final Decision, the AER should therefore have regard for the credit metrics required by ratings agencies to meet a A-/BBB+ threshold, and ensure that those metrics are met.

We will also continue to consider how best to assess this issue leading in our Final Plan.

14.4 Prices

As already noted, we recover our revenue through the prices that we charge retailers for providing reference services. This section outlines our current and proposed pricing structures.

14.4.1 Current Pricing Structure

Our pricing structure includes five tariff zones:

- Central;
- Northern;
- Murray Valley;
- Bairnsdale; and
- Albury.

Both our residential and commercial tariffs comprise these five zones.

Our industrial tariff comprises four zones:

- Central/Northern;
- Murray Valley;
- Bairnsdale; and
- Albury.

Prices for residential and commercial customers 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).

The residential pricing structure is made up of a fixed charge and three volumetric tariff components, whilst the commercial pricing structure is made up of a fixed charge and four volumetric tariff components

We currently recover approximately 75% of our

Table 14.3: Draft Plan Key Credit Ratios, 2023/24 to 2027/28

	2023/24	2024/25	2025/26	2026/27	2027/28	Average
FFO to Debt	6.8%	7.0%	7.4%	7.2%	7.1%	7.1%
FFO to Interest Cover	2.7	2.8	3.0	3.0	3.1	2.9

Table 14.4: Charging Parameters by Customer Type

Residential (Tariff R)	Commercial (Tariff C)	Industrial (Tariff D)
Fixed Charge	Fixed Charge	
0 - 10 GJ	0 - 18.25 GJ	0 - 10 GJ MHQ
10 - 18 GJ	18.25 - 200.75 GJ	10 - 50 GJ MHQ
> 18 GJ	200.75 - 500.05 GJ	> 50 GJ MHQ
	500.05 GJ +	

revenue in the residential and commercial segments in the variable (volumetric) components of our tariffs and 25% through the fixed components. This reflects previous stakeholder feedback that a higher proportion of volumetric charges and a lower proportion of fixed charges are preferred as this structure more closely reflects user based pricing.

Prices for our industrial customers are capacity based and consist of a number of banded charging parameters (in dollars per GJ of MHQ) (see Table 14.4). All prices decline as usage increases to promote better network utilisation.

14.4.2 Declining Block Tariff Structure

Both the residential and commercial pricing bands (or components) decrease as customer usage increases (often referred to as declining block tariffs). This pricing structure:

- reflects the relatively low marginal cost associated with increasing the supply of gas to a customer; and
- encourages greater network utilisation by promoting connection of more gas appliances, which is part of the package of measures that we use to address the observed long-term decline in demand per connection (see Chapter 13).

For instance, our first residential pricing band broadly captures a customer using a gas cooker and gas boosted solar hot water system, the second step captures a customer with a non-solar gas hot water system while the final step captures customers utilising gas for space heating.

Given declining average gas consumption, our tariff structure is designed to encourage greater network utilisation. We consider our pricing structures align with our obligations that require us to promote the efficient use of the network.

We therefore consider there is strong merit in retaining the existing declining pricing structure.

14.4.3 Form of Revenue Control

We propose to continue with the current form of revenue control, i.e. a price cap, because it promotes the efficient utilisation of the network by providing an incentive for us to grow our customer base and volumes on our network.

We do not consider that the price-cap form of revenue control is inconsistent with governments' decarbonisation policies because our goal is to decarbonise the gas that we deliver through our networks. The current structure will therefore continue to stimulate demand as is currently the case. Conversely, we do not consider a revenue cap appropriate given the disincentive it would provide to grow the network, which in turn would hamper the transition to renewable gases.

We therefore consider there is strong merit in retaining the existing declining pricing structure and form of revenue control.

14.4.4 Declining Block Tariff Structure

Both the residential and commercial pricing bands (or components) decrease as customer usage increases (often referred to as declining block tariffs). This pricing structure:

- reflects the relatively low marginal cost associated with increasing the supply of gas to a customer; and
- encourages greater network utilisation by promoting connection of more gas appliances, which is part of the package of measures that we use to address the observed long-term decline in demand per connection (see Chapter 13).

For instance, our first residential pricing band broadly captures a customer using a gas cooker and gas boosted solar hot water system, the second step captures a customer with a non-solar gas

hot water system while the final step captures customers utilising gas for space heating.

Given declining average gas consumption, our tariff structure is designed to encourage greater network utilisation. We consider our pricing structures align with our obligations that require us to promote the efficient use of the network.

We therefore consider there is strong merit in retaining the existing declining pricing structure.

14.5 Summary

We recover our costs, or building block revenue, through the prices that we charge for providing network services. We have proposed to cut our network prices in Victoria and Albury by 8% (after inflation) on 1 July 2023.

We consider that it is good regulatory practice for the AER to deliver a decision which delivers sufficient cash flows to maintain the A- to BBB+ credit rating assumed by the AER in setting the return on debt to ensure the decision is internally consistent.

This has always been a challenge in gas given the slow depreciation rate (or speed of money). Our accelerated depreciation proposal in response to the future of gas helps this, but not to the point whereby we meet required credit thresholds, we will continue to consider this leading into the Final Plan.

15 Network Access

We have been standardising the Terms and Conditions which govern how users access our network, across our networks.

IN THIS CHAPTER:

- **We propose to continue the process of standardising our Terms and Conditions across our networks.**

Our reference service Terms and Conditions set the contractual arrangements between AGN and network users.

A key part of our relationship with network users 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'.[31] 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.

The following sections outline the process we will follow to develop our proposed terms of access to our Victorian gas distribution network over the next (2023/24 to 2027/28) AA period.

We also describe briefly the changes we are proposing to the Terms and Conditions from those in place during the current (1 January 2018 to 31 December 2022) AA period. The Terms and Conditions are set out in our AA Document, which will be provided alongside the Final Plan to be submitted to the AER by 1 July 2022.

15.1 Regulatory Framework

We are required under the NGR[32] to specify the Terms and Conditions on which each reference service will be provided in our Final Plan.

15.2 Stakeholder engagement

Our Terms and Conditions will be subject to considerable stakeholder engagement through a number of successive AA review processes, and consequently, will be amended over time to take into account feedback we receive from stakeholders and decisions made by the AER.

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.

In November 2021 we provided retailers with a proposed draft of the terms to apply to our Victorian and Albury network. As well as providing a marked up version of the suggested changes to the Terms and Conditions, AGN also provided to retailers a set of notes, which explain the reason for changes proposed.

AGN has received responses from retailers to its proposed draft Terms and Conditions. Issues raised by retailers include:

- removing the requirement for retailers to provide credit support to AGN.
- removing charges for a disconnected (or vacant) site.

15.3 Approach

We commenced a process of standardising our terms across all jurisdictions where we have networks back in 2012.

We believe there are many benefits to our customers from standardising terms of access as it promotes greater efficiency across

[31] Network users are primarily gas retailers or self-contracting users of our networks.
[32] NGR 48(d)(ii))

the industry and reduces transaction costs.

Our approach to developing the proposed Terms and Conditions includes:

- harmonising the proposed terms with the South Australian Terms and Conditions (which were reviewed and approved by the AER in April, 2021) taking into consideration any jurisdictional differences requiring variation;
- incorporating common amendments recently incorporated into Haulage Agreements across AGN's networks, where relevant, which improve alignment and efficiency in the Terms and Conditions;
- correcting typographical errors and anomalies;
- accommodating changes in regulatory instruments;
- incorporating feedback from our Retailer Reference Group on up to three drafts of our proposed Terms and Conditions; and
- incorporating feedback from the Draft Plan on the proposed Terms and Conditions in preparing our Final Plan.

15.4 Summary

The Terms and Conditions are a key part of our relationship with network users. The proposed Terms and Conditions are the basis that users gain access to our networks and generally form the basis for the contractual agreement entered into between the parties. They have gone through considerable consultation with stakeholders over the past 5-10 years.

In the lead up to the Final Plan submission on 1 July 2022, we will work with retailers to resolve the issues raised, in particular, the issue of credit support and charging the fixed component of our tariff for disconnected site.

Glossary			
AA	Access Arrangement	HIA	Housing Industry Association
ACQ	Annual Contract Quantities	HSE	Health Safety Environment
AER	Australian Energy Regulator	HyP	Hydrogen Park
AGIG	Australian Gas Infrastructure Group	I&C	Industrial and Commercial (customers)
AGN	Australian Gas Networks	ILI	In Line Inspection
AHC	Australian Hydrogen Centre	KPI	Key Performance Indicator
AMP	Asset Management Plan	LPG	Liquid Petroleum Gas
AMS	Asset Management Strategy	MDQ	Maximum Daily Quantity
ARENA	Australian Renewable Energy Agency	MFP	Multifactor Productivity
ARS	Ancillary Reference Service	MGN	Multinet Gas Networks
capex	Capital Expenditure	MRP	Market Risk Premium
CBD	Central Business District	Next AA period	2023/24 to 2027/28
CSIRO	Commonwealth Scientific and Industrial Research Organisation	NGL	National Gas Law
Current AA period	2018 to 2022	NGR	National Gas Rules
DBP	Dampier Bunbury Pipeline	opex	Operating Expenditure
DCVG	Direct Current Voltage Gradient	PMC	Periodic Meter Change
DP	Delivery Point	RBA	Reserve Bank of Australia
DRP	Debt Risk Premium	RRG	Retailer Reference Group
EBSS	Efficiency Benefit Sharing Scheme	SCADA	Supervisory Control and Data Acquisition
EDD	Effective Degree Day	SL CAPM	Sharpe-Lintner Capital Asset Pricing Model
ESCV	Essential Services Commission of Victoria	TAB	Tax Asset Base
ESV	Energy Safe Victoria	TFP	Total Factor Productivity
FFO	Funds from operations	TJ	Terajoule/s
GDB	Gas Distribution Business	TRIFR	Total Recordable Injury Frequency Rate (the number of total recordable injuries per million hours worked)
GJ	Gigajoule/s	UAFG	Unaccounted for Gas
GSP	Gross State Product	VGNSR	Victorian Gas Networks Stakeholder Roundtable
HDPE	High-Density Polyethylene	WPI	Wage Price Index

Australian Gas Networks

Lower prices

↓8%

(after inflation)

We have engaged with customers in Victoria and Albury to develop our Draft Plan for the five year period 2023/24 to 2027/28

In line with what our customers told us was important to them, this plan has 3 key themes:

- **Get the basics right**
- **Focus on the future**
- **Provide affordable and accessible services**

Lower funding costs

Rate of return of 4.21 % down from 5.75 % in the last period

Efficient incentives

- Opex & Capex Efficiency Schemes
- Gas Network Innovation Scheme

Safety focus

Maintain strong leak performance and continue to monitor performance and condition of mains

Future focus

Investing in 'no regrets actions' and renewable gas communications to prepare the network for a decarbonised future

Customer focus

- New digital customer services
- Priority Services Program

Keeping options open

Supports the long term competitiveness of the network to provide energy choice for customers in a net zero carbon future

Feedback

The consultation period for this document closes 7 March 2022.

For more information, or to set up a stakeholder meeting, please contact:

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