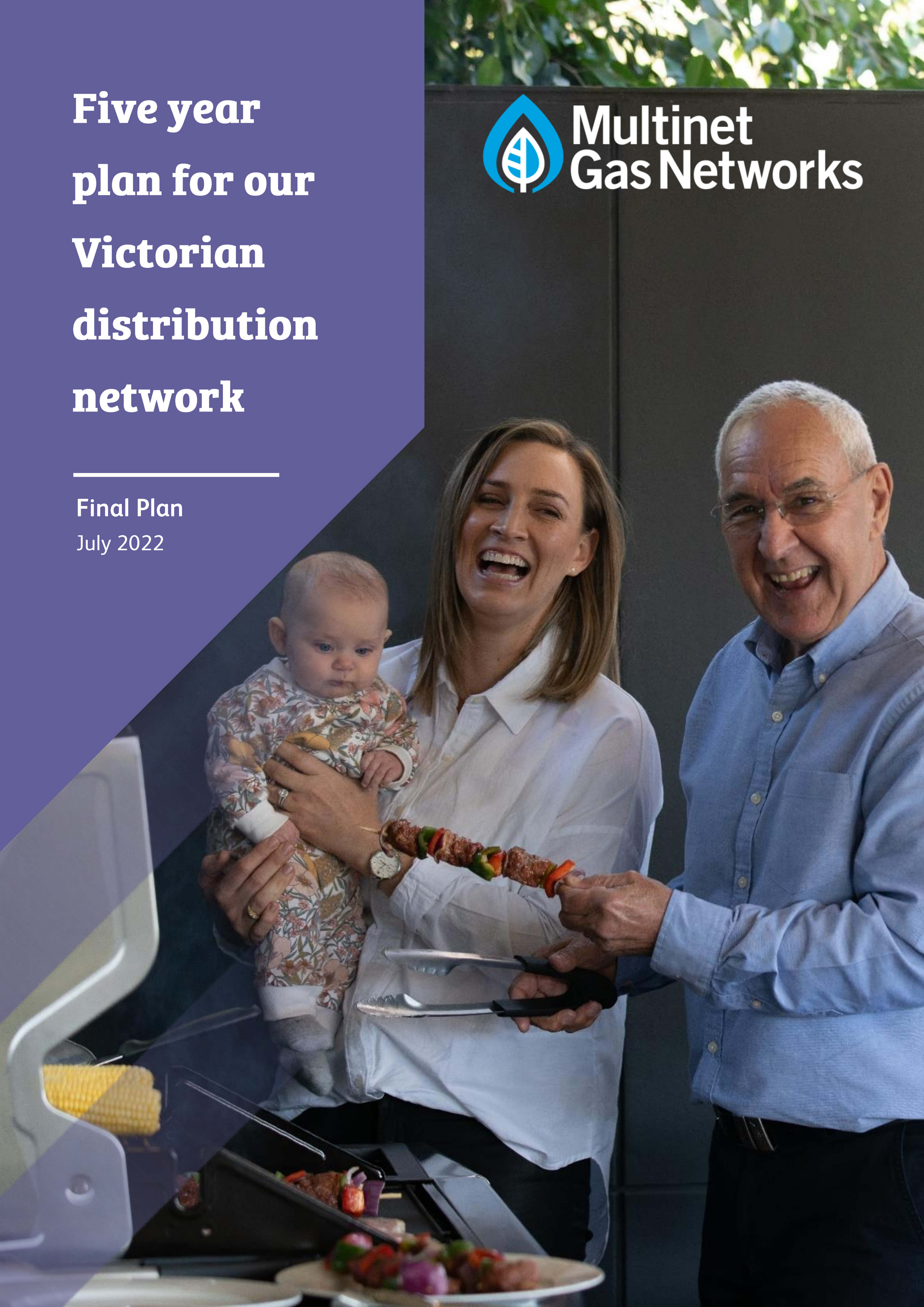
Five year plan for our Victorian distribution network

Final Plan

July 2022



Contents

We are Multinet Gas Networks. We deliver gas safely and reliably to more around 720,000 homes and businesses in Victoria 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 into the future.

CEO Foreword

I am pleased to present the Multinet Gas Networks (MGN) Final Plan for the 2023/24 to 2027/28 period.

This document sets out our plan for the next 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.

MGN is part of the Australian Gas Infrastructure Group (AGIG), one of Australia's largest energy infrastructure businesses. Through MGN, we serve around 720,000 customers in Victoria, including in Melbourne's inner and outer east, the Yarra Ranges and South Gippsland. MGN plays a vital role in delivering safe, reliable, affordable and low emissions energy for our residential, commercial and industrial customers.

In serving our 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. We are also leading the industry in its transition to a renewable gas future.

We will target 100% renewable gas in distribution networks by 2050 at the latest and 2040 as a stretch.

In the current AA period we have performed strongly towards our vision. Our customer satisfaction scores have improved throughout the period, reaching the highest score to date 8.1 for MGN in 2021. We have repaired 98% of leaks within one hour and continued to improve our performance against health and safety metrics.

In the current AA period we have delivered over 600 kilometres of mains replacement, 17% above the benchmark for the period. Finally, we have achieved real operating costs savings of 20% relative to our benchmarks.

Our Final Plan has been developed following a significant program of customer and stakeholder engagement. Our program has delivered repeat engagement to 106 customers and stakeholders, included through 15 workshops.

The Final Plan reflects on the feedback received from customers and stakeholders up to and after the publication of the Draft Plan in January 2022.

In an Australian first, the three gas distribution businesses in Victoria and Albury (AusNet Services, Australian Gas Networks and ourselves) conducted joint engagement with stakeholders to inform the development of our respective Final Plans. This was in response to stakeholder requests very early in our engagement process, and has served both stakeholders and the gas networks well because of the common issues that we face.

We have developed this Final Plan against the backdrop of significant policy uncertainty on the future role of our gas networks. This will likely continue and evolve over the next AA period, as Victoria starts to plan for the decarbonisation of the gas sector in meeting its 2030 emissions reduction target and ultimately achieving its legislated target of net zero emissions by 2050.

While we consider that natural gas has an important role to play in Victoria's energy sector today, we recognise that if Victoria is to meet its emission reduction targets we need to focus on large-scale decarbonisation of our Victorian distribution network.

Our Board has recently endorsed a low carbon strategy that includes targets to deliver 100% renewable gas solutions from 2025, deliver at least 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 by 2050 at the latest.

These targets align with government policy and our expectations for future technological developments in renewable hydrogen (and other renewable gases). We believe our network will continue to maintain a pivotal role in the energy sector of the future, delivering renewable gases like hydrogen and biomethane to our customers.

Given the current policy uncertainty, our Final Plan aims to create options for our customers by preserving choice in their future energy supply. In particular, we will continue to connect customers reflective of their ongoing demand for gas in their homes and businesses. For MGN, continued network growth in the next AA period will see around 36,000 new customer connections. These new connections will also help to lower costs for existing customers and provide new customers with the infrastructure ready to deliver renewable gases.

However we also recognise the future role of gas networks will vary significantly depending on technological developments, government policy and the cumulative decisions of Victorian customers as the economy transitions to net zero emissions.

To start addressing the risks that may arise if there is a rapid decline in gas demand, this Final Plan proposes a modest amount of accelerated depreciation ($76 million, equivalent to around 5% of the total value of gas network).

Adjusting depreciation is the right tool to address the uncertainty we face, and provides a means to maintain the cost competitiveness of our network in the near term in delivering natural gas and in the long term enabling us to be a most competitive part of a net-zero emissions energy system.

In adjusting depreciation we have been careful to avoid exposing customers to significant price disruption. The approach adopted is measured – balancing the risks and opportunities of an uncertain future, while delivering improved value for customers.

Our proposed approach means customers do not pay more over the life of the asset, rather the profile of asset recovery is adjusted. Importantly, our approach to take small steps now to accelerate depreciation will provide more stable prices for customers through time, while keeping future options open.

Our Final Plan also delivers a number of complimentary actions which will ensure a smooth transition to net zero, such as small amounts of expenditure to prepare the network for hydrogen and a renewable gas communication and education program.

For MGN continued progress on mains replacement is a key objective in the next AA period. It is one of our key safety obligations and will further improve the safety and reliability of our network and reduce emissions in the near-term. At the same time, it will help to ready our network for 100% renewable hydrogen in the future.

We have also included on a range of important initiatives supported by our customers and stakeholders. This includes:

- Investment to improve our customer communications through a range of digital channels; and
- Investing in a Priority Service Program.

In response to feedback from our customers and stakeholders received on our Draft Plan published in January, we have decided not to propose a new gas network innovation scheme at this time despite customer support.

We consider our proposal strikes the right balance of continuing to provide the services customers expect of us today, while also taking small steps to prepare for the transition to a decarbonised energy future, delivering for customers today. Our proposal will ensure the network can continue to deliver safe, reliable and affordable energy to customers now and into the future.

Overall, our Final Plan delivers an upfront price cut of 1% (after inflation) on 1 July 2023, which builds on stable prices delivered by our business in the current period.

The Final Plan will now form the basis of a review by the Australian Energy Regulator (AER), which will commence its consultation process. I strongly encourage our customers and stakeholders to participate in the AER's process to ensure we provide the services that customers value.

Craig de Laine

Chief Executive Officer

Multinet Gas Networks

Stable prices

↓ **1%**
(after inflation)

We have engaged with Victorians to develop our Final 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 5.13 % down from 5.75 % in the last period

Keeping options open

Supports long term interests of customers, price stability and cost competitiveness of the network to provide energy choice for customers

Safety focus

Replacing over 800km of old low pressure and earliest generation polyethylene 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 Service Program

Efficient incentives

Opex & Capex Efficiency Schemes

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 Final Plan (otherwise known as Access Arrangement (AA) proposal) 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 MGN distribution network.

This includes:

- the services provided to our customers;
- 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 MGN 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 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.

As part of our "no surprises" approach, our stakeholder engagement program has enabled our customers and other stakeholders to inform and shape the Final Plan. This program was well received by our customers and stakeholders.

More details on the stakeholder engagement program and our responses to the feedback received are included in Chapter 5 (Stakeholder Engagement).

This Final Plan provides the activities and expenditure we propose to undertake during the next AA period, incorporating feedback received on the Draft Plan and through stakeholder engagement.

How to read this plan

The first six chapters of this document provide an overview of our plans, our business, our stakeholders and the process we have undertaken to develop a plan that meets our objectives. Chapter 6 the *Future of Gas* explains the approach we have taken to meet challenge of decarbonisation of energy supply in Victoria and Chapter 7 describes our pipeline services.

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 MGN distribution network, 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);
- *Demand forecasts* – the total amount of services we forecast our customers will demand over the period (Chapter 12); and
- *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 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 are quoted throughout this Final Plan are dollars 2022/23, unless otherwise labelled.

Next steps

Shortly after receipt of this Final Plan, the AER will commence a formal engagement process. Customers and other stakeholders are encouraged to participate in this process. We will also continue to engage with our customers and stakeholders over this period. We also welcome any feedback, which can be provided:

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.

The Order sets out that the six-month period 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). It also set out requirements for determining the revenue for the six-month period 1 January to 30 June 2023.

In line with the Order, the AER released a position paper on 8 November 2021 that set out transitional arrangements for the six-months, including how prices would be set and how a revenue adjustment would be made 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.

Variation proposal

On 1 April 2022, we submitted to the AER a proposal for the six-month period 1 January to 30 June 2023. This proposal set out the key building blocks and proposed revenue adjustment in the next AA period consistent with the arrangements detailed in both the Order and the position paper.

We have been engaging with the AER on our Variation Proposal. In this Final Plan, we have incorporated updates to the application of inflation in the six-month extension period compared to what we submitted on 1 April 2022. The forecast true up required to account for the difference between tariff revenue and building block revenue for the six month period has been incorporated into this Final Plan, and is discussed in Chapter 14, Revenue and Pricing.

The AER is expected to publish its Draft Decision for the six-month extension period in July 2022.

1 Plan highlights

Our Final 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 focussing on safety as our top priority, exceeding our target for low pressure mains replacement kilometres, improving customer satisfaction, and delivering real opex savings of around 20% compared to our benchmarks.**
- **We are proposing an upfront price cut of 1% (after inflation) on 1 July 2023, building on the stable prices 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 have engaged extensively with customers and stakeholders and their insights have informed our Final Plan.

This section highlights how we have developed our Final 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.

We held 15 workshops with around 106 customers across three locations over three phases to allow customer input to inform and shape the development of our Final Plan.

In the development of this Final Plan we have completed all four stages of our engagement program (see Chapter 5). Further feedback and engagement activities since our Draft Plan have helped to refine our Final Plan. We will continue to engage with stakeholders through the AER's review process.

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, remain sustainably cost efficient and lead the transition of the economy to renewable gases. 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 98% of leaks within one hour and focusing on minimising interruptions despite recent wet winters presenting challenges from water in mains; and
- Strong customer service – an average of 7.7 customer satisfaction, with a score of 8.1 for 2021, our highest score to date; and
- increasing from 92% to 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) of averaging 4.2 since we began tracking this metric in 2018 and Lost Time Injuries (LTIs) of 2 per annum or lower; and
- Employee engagement and skills development – annual average engagement score of 69%, achieving top decile in 2020 and in or near top quartile for all years; and
- compliance training of 99%.

Sustainably cost efficient

- Stable prices on 1 July 2018;
- On track to deliver over 600 kilometres of mains replacement, which is above the approved benchmark for replacement for the AA period. This sets MGN up to continue the low pressure program at the 2018-2021 replacement rates in the next AA period and will reduce reported scope 1 emissions at the end of the current AA period by 35,000 tonnes (or 15%) of CO2-equivalent per year compared to 2017 levels;
- Real operating cost savings of 20% compared to benchmarks during the first period in which we have operated under both an opex and capex incentive scheme; and
- Made significant progress on Gas Vision 2050, including setting clear decarbonisation targets for the next 4-20 years.

1.3 What we will deliver

Our Final 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;
- Achieving customer satisfaction scores of 8.0 or above;
- Connecting around 36,000 new residential, business and industrial customers;
- Introducing a new Priority Service 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 and embedding our HSE culture model;
- Continuing ongoing health and safety initiatives, including our various wellbeing initiatives; and
- Targeting top quartile employee engagement scores to ensure our staff remain customer and safety focussed.

Sustainably cost efficient

- Delivering an upfront price cut of 1% on 1 July 2023, continuing the stable prices delivered by our business in the current period;
- Minimising increases in combined operating and capital expenditure, outside of our mains replacement program;
- 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 $76 million of depreciation which will reduce risk, provide price stability and support the long term competitiveness of the network to provide energy choice for customers in a net zero carbon future;
    - Investing $9 million in activities to ensure the network is ready for the distribution of hydrogen, which includes updating procedures, testing of existing pipeline welds, replacement of incompatible equipment in hazardous areas and further compatibility studies; and
    - Undertaking a renewable gas communications and education program which

will help customers to feel confident today about future opportunities and the role that renewable gas can play.

2 Our Business

We deliver gas safely and reliably to around 720,000 homes and businesses every year.

IN THIS CHAPTER:

- **MGN 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.**

MGN is part of Australian Gas Infrastructure Group (AGIG), one of the largest gas infrastructure businesses in Australia.

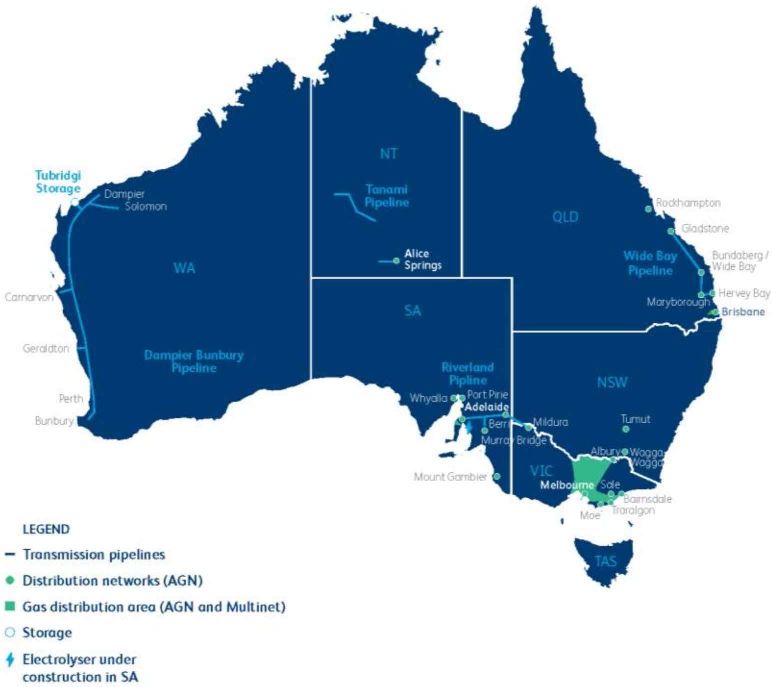
2.1 About AGIG

AGIG serves over two million customers across every mainland state and the Northern Territory. Our assets include around 35,000km of distribution networks, 4,400km of transmission pipelined and 60 petajoules of storage capacity.

In 2017 Australian Gas Networks (AGN), 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 MGN's customers in Victoria and Albury in the current AA period as outlined in Chapter 3 below.

AGIG is also leading the decarbonisation of gas supply in Australia. We are already injecting a 5% 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 2.7 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.

Discussed further in Section 2.7 below, we are committed to sustainable gas delivery today, and for tomorrow. For our distribution networks, AGIG is targeting 10% renewable gas by 2030. Our aim is to fully decarbonise our distribution networks by no later than 2050, with the stretch goal set for 2040.

The activities and investments in this Final 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 inaugural Environmental, Social and Governance 2021 Report.

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 generations.

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 Final 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 Final 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.

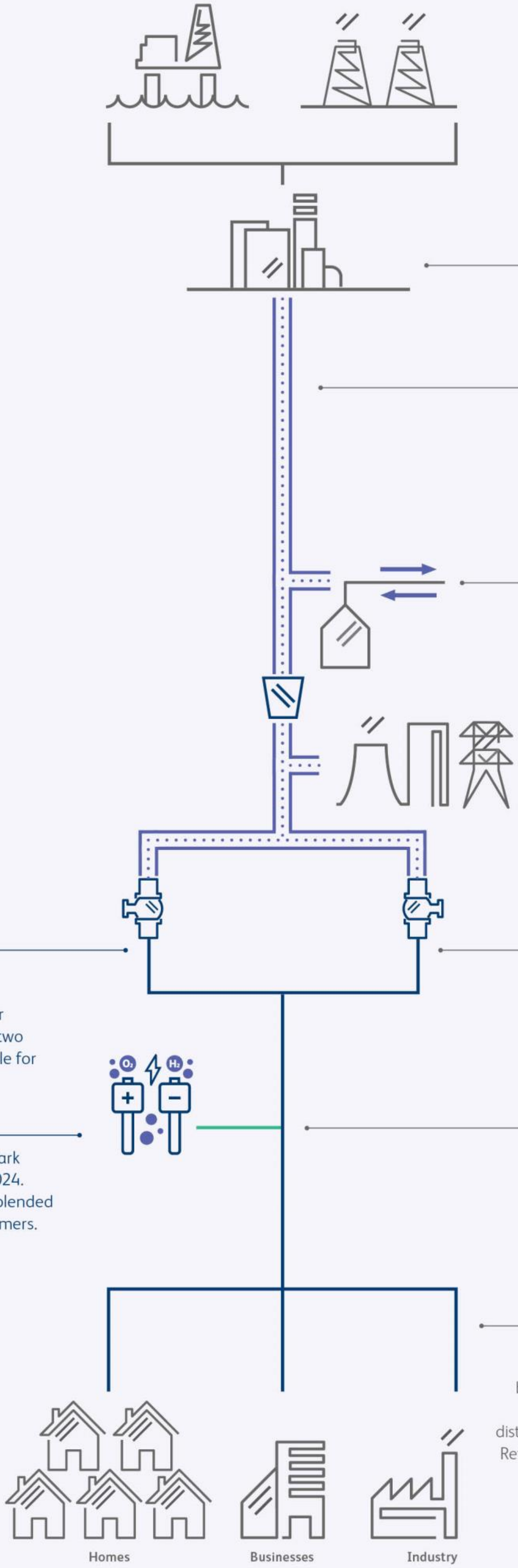
Figure 2.3 shows the location and key features of the MGN network. The network is more than 10,104 km long, serving residential, commercial and industrial business customers throughout Melbourne's inner and outer east, the Yarra Ranges and South Gippsland.

Our Services

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

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 demand.

Large users and power generation
Most large gas users connect directly to transmission pipelines to source gas for their operations.

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.

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

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.

Renewable gas
The gas sector's vision for the future includes supplying renewable/carbon-neutral gas including biomethane and renewable hydrogen to customers. Numerous facilities across Australia are operational and/or under construction.

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. Retailer's bill customers for providing these services.

- AGIG Services
- Non-AGIG Services

Multinet Gas Networks

10,104
Kilometres of mains

56PJ
Gas delivered in 2021

719,436
Customers

8.1
Customer satisfaction score

2.8 Our low carbon vision

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:

- 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 federal, 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 a 10% green hydrogen gas blend (by volume), produced with 100% renewable electricity[1] to around 40,000 residential, commercial and industrial customers in Albury and Wodonga (part of the AGN Victoria and Albury network). 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), part of the AGN SA network, 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. We have recently announced plans to expand the reach of HyP SA to supply over 4000 homes, by the close of 2022.

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 2023.

In Western Australia we have recently completed a feasibility study determining how the Dampier Bunbury Pipeline can introduce hydrogen into its mix. As a result of this study, there is now a clear pathway for declaring a pipeline section as suitable for use with hydrogen/natural gas blends. This study was supported by the Western Australian Government.

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.

[1] 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 renewable gas (hydrogen and biomethane and its 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 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 hydrogen and renewable gas, just as they currently do with respect to natural gas.

The reforms will also enable hydrogen 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 focus on safety, reliability and efficiency by replacing over 600 kilometres of low pressure mains with high pressure mains and continuing to reduce our operating costs.

IN THIS CHAPTER:

- **We continue to focus on safety as our top priority, with strong performance against our measures and replacement of over 600 kilometres of low pressure mains.**
- **Through low pressure mains replacement, we have also reduced our reported scope 1 emissions by 35,000 tonnes CO_2-e pa (or 15%) compared to 2017 levels.**
- **We have delivered real opex savings of around 20% compared to our benchmarks, while also connecting a forecast 25,000 net new customers. Both of these will benefit customers through lower prices in the next period.**
- **Our strong focus on customer service has also seen increased customer satisfaction from 7.2 in 2018 to 8.1 in 2021.**

Our focus in the current period has been on maintaining the safety and reliability of the network, continuing to replace old material low pressure mains as quickly as possible, connecting new customers to our network and reducing costs.

This is our first full period as a part of AGIG. 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 ourselves a number of targets that we could use to measure how we have delivered against our vision. These targets were shared in our Access Arrangement Information, December 2016.

Figure 3.1 below summarises our performance in the current period to date against these targets.

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

However, we experienced our worst winter performance in terms of outages and complaints in

2021. Around 1,500 kilometres of low pressure mains which are subject to water ingress and outages remain in our network. The wet winters coupled with more people at home have seen this impact some of our customers.

In response we have ramped up reactive works to address the most severe pockets, however this is an expensive way to replace mains and our plans for the next period are to continue the proactive replacement of the remaining low pressure mains in our network as quickly as possible.

3.1 Delivering for customers

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

Our 2018 to 2022 targets included delivering low pressure mains replacement, continuing to focus on safety as our top priority by reducing and responding quickly to leaks, meeting our customers' needs in terms of reliability by outperforming SAIFI and SAIDI targets and improving customer satisfaction.

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

- Replacing over 600 kilometres of low pressure mains with high pressure mains;
- Network leaks of 19 per 1,000 customers per annum, with 98% of leaks repaired within the timeframes set by the safety regulator;
- 89% of Emergency calls have been answered within 10 seconds, up from 81% in 2018;
- Gas Safety Case approved; and
- Improving our customer satisfaction scores to 8.1 in 2021, following continued improvement in our scores over the period.

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 included outperforming health and safety metrics and investing in specialist skills and resources.

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

- Adopting a new approach to tracking health and safety, with Total Recordable Injury Frequency Rate (TRIFR) averaging 4.2 since we began tracking this metric in 2018 and Lost Time Injuries (LTIs) of two or fewer in each year of the period so far;
- 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
- 99% 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 seeking efficiencies through competitive retendering of service delivery contracts and connecting new customers.

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

- achieving efficient pricing on mains replacement which has allowed us to replace over 600 kilometres of low pressure mains compared to the 530 kilometres approved;
- considerably reducing our real operating costs, which have been 20% lower than the benchmarks;
- 37,500 gross new connections to our network to December 2021 including in the new areas of South Gippsland and Warburton, who can choose gas for the first time;
- Reducing reported scope 1 emissions by 35,000 tonnes of CO_2-e pa (or 15%) compared to 2017 levels through the replacement of old low pressure mains; and
- making significant progress on Gas Vision 2050 and setting ambitious decarbonisation targets over the next 4-20 years.

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

Delivering for customers

Which means

- Public safety
- Reliability
- Customer service

Our performance 2018 to date

- Over 600 kilometres of high pressure mains to replace low pressure mains (against 530 kilometres approved)
- Network leaks of 19 per 1,000 customers per annum, with 98 % of leaks repaired within the timeframes set by the safety regulator (both better than target of 25 per 1000 and 95 %)
- 91 % of emergency calls answered within 10 seconds in 2020, up from 81 % in 2018
- Gas Safety Case approved
- SAIFI (planned and unplanned) performance averaging 18.9 per 1,000 customers (compared to target of 16.2)
- SAIDI performance (planned and unplanned) averaging 7 minutes per customer (compared to target of 5)
- Customer satisfaction survey scored an average of 7.7, our highest score to date of 8.1 in 2021

Vision

A good employer

Which means

- Health & Safety
- Employee Engagement
- Skills Development

Our performance 2018 to date

- New approach to tracking health and safety, with Total Recordable Injury Frequency Rate (TRIFR) averaging 4.2 since we began tracking this metric in 2018 and Lost Time Injuries (LTIs) of two or fewer in each year of the period so far
- Employee engagement annual average score of 69 %, remaining at or near the top quartile every year
- Compliance training: 99 % per cent completion

Vision

Sustainably cost efficient

Which means

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

Our performance 2018 to date

- Stable prices on 1 January 2018
- Operating costs have been within the benchmarks set for the business, with real savings of around 20 %
- 37,500 gross new connections to our network to date including in the new areas of South Gippsland and Warburton, who can choose gas for the first time
- Lowering reported scope 1 emissions by 35,000 tonnes of CO_2-e pa (or 15 %) compared to 2017 levels through the replacement of old low pressure mains
- Made significant progress on Gas Vision 2050 and set ambitious decarbonisation targets over the next 20 years

4 What we will deliver

This Final 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 1% (after inflation) on 1 July 2023, following stable prices delivered on 1 January 2018.**
- **We will connect around 36,000 new customers, with our total customer base expected to exceed 720,000 by the end of the period.**
- **We will invest $9 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 Victorians to develop our Final 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 Final Plan presents stable 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;
- Continuing our low pressure mains replacement program at current rates as well as proactively replacing some of the earliest generation polyethylene mains and medium pressure steel mains exhibiting corrosion to address continuing safety and reliability risks associated with these mains, with the added benefit of making our network hydrogen ready;
- Maintaining customer satisfaction scores of 8.0 or above;

- Laying reticulation mains and services, and installing meters, to connect around 36,000 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 1% (after inflation) on 1 July 2023, which builds on the stable prices delivered by our business in the current period. This will see bill impacts to the average residential customer of $24 per year, commercial $60 per year and industrial $1,864 per year[2];
- minimising increases in combined operating and capital expenditure outside of the impact of our safety driven mains replacement program;
- 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 $76 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 $9 million in activities to ensure the network is ready for the distribution of hydrogen which includes updating procedures, testing of existing pipeline welds, replacement of incompatible equipment in hazardous areas and further compatibility studies; and
  - Delivering a renewable gas education program which will help inform our current and future customers to feel confident developments are being made today for renewable gas to be available in the future. This is an important part of being a prudent service provider acting efficiently to ensure our customers are informed and educated about such a large transition.

[2] This bill estimate assumes inflation of 3.05% per annum in years 2 – 5.

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

Vision

Delivering for customers

Which means

- Public safety
- Reliability
- Customer service

Our performance targets 2023/24 – 2027/28

- 90 % of emergency calls answered within 10 seconds
- >95 % of public leaks responded to within required timeframes
- 100 % of priority leaks repaired in timeframes set out in our leak management plan
- 100 % of leak surveys completed on time
- Customer satisfaction survey score above 8.0
- Around 36,000 new connections, with more than 98 % completed within the required 20 days
- 80 % of complaints resolved within two days
- Limit gas supply interruptions to 1 in every 30 years or fewer

Vision

A good employer

Which means

- Health & Safety
- Employee Engagement
- Skills Development

Our performance targets 2023/24 – 2027/28

- Total Recordable Injury Frequency Rate (TRIFR): <7
- Top quartile employee engagement scores
- 99 % compliance training completion

Vision

Sustainably cost efficient

Which means

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

Our performance targets 2023/24 – 2027/28

- Initial price cut of 1 % (after inflation) on 1 July 2023
- Around 820km of mains replacement including 704km of low pressure mains, 86km of HDPE 250 and 30km of medium pressure steel
- Deliver efficiency benefits through the EBSS and CESS schemes
- Making sure our network and customers are prepared for hydrogen and renewable gas blending:
    - Deliver renewable gas education program
    - Complete hydrogen readiness activities

5 Customer and Stakeholder Engagement

Our Final Plan incorporates what customers have told us are their needs and expectations of MGN. With customers at the centre of our planning, our Final Plan is underpinned by the most extensive customer and stakeholder engagement program undertaken at MGN to date.

IN THIS CHAPTER:

- **In an Australian first we undertook joint engagement with Australian Gas Networks and AusNet Services, bringing the three Victorian gas distribution businesses together for the purposes of open and transparent engagement.**
- **We held 15 workshops with customers across 3 locations over 3 phases to allow customer input to inform and shape the development of our plan.**
- **We received strong support from our customers, with more than 90% of customers supporting our plans.**
- **We have worked together with two reference groups of consumer representatives and retailers, who have also inputted into the development of our Final Plan.**

Our Plan is underpinned by effective and transparent customer and stakeholder engagement.

Together with AGN and AusNet Services (AusNet), we have engaged extensively with a broad cross section of customers and stakeholders to guide the development of our Final Plan.

Our engagement does not, however, end with this Final Plan submission to the Australian AER. We will continue to engage to ensure that our plans deliver on what matters most to our customers and stakeholders.

This chapter 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.

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 approached to our engagement program, which is illustrated in Figure 5.1. We use this framework to report the outcomes against our engagement activities.

In February 2021 we consulted on our draft engagement strategy as part of Stage 1. We believe this a critical step in the process as it ensures our engagement program is fit for purpose and identifies key topics for consultation early in the process.

Our Final Plan objectives:

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

Innovation in Engagement, Engaging Victorians on the future of our Networks

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.

This presented an innovative opportunity for the three Victorian Gas Networks to deliver a comprehensive engagement program for all Victorians.

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.

Figure 5.1. Our four staged approach to customer and stakeholder engagement

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 – May 2022**	**May 2022 – ongoing**
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.

Our Customer and Stakeholder Engagement Process

We commenced our customer and stakeholder engagement program 18 months prior to the lodgement of this Final Plan.

We delivered a range of engagement activities with customers and stakeholders to support the development of our plans, including:

- ✓ 10 meetings of the VGNSR and RRG;
- ✓ Four combined VGNSR and RRG deep-dive workshops on our Draft Plan proposal;
- ✓ Three phases of customer workshops with over 100 MGN customers;
- ✓ A workshop with CALD customers South Melbourne in partnership with the ECCV;
- ✓ Three forums with major gas users in collaboration with EUAA and Ai Group;
- ✓ Six meetings of the Future of Gas Expert Panel, four of which were dedicated to a co-design process;
- ✓ Three workshops with the Priority Services Advisory Panel to design new services to support customers experiencing vulnerability.
- ✓ Two Independent Review sessions with the RRG and VGNSR to gather views on how we had responded to their feedback on our Draft Plan. These sessions were facilitated and reported by KPMG and we did not attend.

Our engagement journey is illustrated in figure 5.2 and shows our iterative engagement process with customers and stakeholders.

Critical to our program has been the ongoing engagement with our two stakeholder reference groups through a series of meetings and deep-dive 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 and NSW (Albury).

Through 14 meetings and workshops we consulted with stakeholders on topics including:

- our pipeline services;
- customer experience and flexible solutions;
- our price structure;
- 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 Tables 5.7, 5.8 and 5.9 of this chapter.

We also actively engaged and met with members of the AER's Consumer Challenge Panel (CCP). CCP28 were invited to attend and observe our engagement activities. The CCP is appointed by the AER to advise them on whether the long-term interests of consumers are being appropriately considered in the AER's decision-making and assessing network's engagement processes including how networks respond to consumer feedback.

We engaged on a broad range of complex topics

Our engagement program covers a broad range of often complex topics. In developing the list of topics (see Table 5.1), 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.

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). The potential role gas will play in a low carbon future, and how to best consider and respond to uncertainty.

Regular customer engagement allowed us to develop our plans iteratively

Engaging directly with customers in the development of the Final Plan is an important part of our engagement program to ensure we respond to customer needs and expectations. Our customer engagement workshops were run in three phases with the same groups of customers, allowing iterative engagement as our plans were developed. We held dedicated workshops for residential, business, metropolitan, regional and culturally and linguistically diverse (CALD) customers. 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;
- ✓ Three phases of workshops were held in three locations with more than 100 MGN customers (15 workshops undertaken in total); and
- ✓ Customer workshops were facilitated by an independent third party (KPMG) to capture and report how customer feedback was captured and documented.

Across the three phases of workshops we covered the following topics with customers: price and affordability; reliability of service; public safety; customer service; sustainability; and innovation.

Table 5.1: Key Topics for Engagement

Key topics
Price and Affordability
• Price Paths
• Intergenerational equity
Public Safety
Reliability of Supply
Customer Service & Experience
• Services for customers experiencing vulnerability
• Digital services
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)
Mains Replacement
Innovation
Impacts of COVID-19
Regulatory Building Blocks
• Pipeline services
• Capital base
• Depreciation
• Demand forecasting
• Capex & Opex proposals
• Incentives
• Revenue & Pricing

The first phase of workshops were designed to understand customer values, needs and service expectations.

In the following phase of customer workshops, we validated customer feedback, explored issues of importance further and tested costed proposals for feedback.

And in the third phase we presented the Draft Plan proposals to customers and further explored key issues including innovation, education, sustainability and vulnerable customer assistance. More detail about the information we presented at customer workshops, the questions we asked and their feedback is outlined in section 5.5.1 of this chapter.

A full customer engagement report by KPMG can be found on our Gas Matters website (gasmatters.agig.com.au).

We developed an expert panel to develop future scenarios for gas beyond 2030

The future of gas and how we respond in the coming regulatory period was a critical topic of engagement among customers and stakeholders.

To better understand what the future might look like, we established a future of Gas Expert Panel comprising of nine high profile industry leaders with expertise across the energy supply chain including the CSIRO, Grattan Institute and Energy Consumers Australia. This Panel was formed to leverage the unique skills and expertise of each of the panel members.

More detail about the Expert Panel and their work can be found in section 5.4.3 of this chapter.

We collaborated with social service and community stakeholders to design improved services for priority service customers

We are committed to delivering for all customers, including supporting those who are experiencing vulnerable circumstances in our community.

We worked closely with social services organisations, through a series of workshops, to collaboratively design a program to improve the quality of services we deliver to customers who need us the most.

You can read more about our Priority Services Program in section 5.4.4. of this chapter.

We consulted widely on our Draft Plan

Publishing and consulting on our Draft Plan is a key step in our engagement program. It allows us to share our expenditure proposals in the context of the overall price outcome and seek feedback to refine our plans.

We published our Draft Plan in January 2022. Open for consultation for a six-week period, we published it online and distributed a copy to major customers, retailers, government agencies, reference group members and other stakeholders. We received two submissions on our Draft Plan.

We also developed a customer overview of the Draft Plan which was sent to customer workshops prior to round 3 workshops. Our third phase of customer workshops was conducted during the Draft Plan consultation, which allowed direct customer feedback on the Draft Plan.

To support consultation with stakeholders on our Draft Plan we ran four deep-dive workshops combining our stakeholder reference group members.

We also engaged KPMG to undertake 2 facilitated discussions with VGNSR and RRG members to test their views on how we had responded to their feedback on our Draft Plans.

We received five separate submissions from retailers relating specifically to our draft Terms and Conditions. All submissions are included in Attachment 5.1.

Draft Plan feedback and how we have responded is discussed throughout out submission.

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: -

- ✓ Five year plan for our Victoria and Albury Distribution Networks (July 2023 – June 2028) – Draft Plan
- ✓ 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 KPMG 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 Service Program Advisory panel workshop materials
- ✓ Gas Network Innovation Scheme insights reports
- ✓ Draft Plan Deep-Dive workshop presentation materials and minutes

Figure 5.2: Our Customer and Stakeholder Process
2021 - 2022

Multinet Gas Networks

2020

June
Commenced planning with AusNet and AGN on our joint engagement approach.

AusNet services
Australian Gas Networks
Multinet Gas Networks

2021

Stage 1
Strategy and Research

Feb-April
We engaged with our VGNSR and RRG members to better understand customer needs and to consult on our proposed engagement approach.

March
We published our joint Draft Engagement Plan for Consultation
We asked stakeholders including our VGNSR, RRG, Government agencies and customers, if our proposed joint engagement was appropriate for our customers and stakeholders.

3 & 29 March
VGNSR meetings

11 & 31 March
RRG Meetings
We consulted with reference groups on our reference service proposal and draft terms and conditions.

March
Gas Matters online engagement portal launched

Stage 2
Developing our Draft Plan

27 May
VGNSR Meeting

May-Dec
Meetings with key stakeholders
One-on-one meetings with key stakeholders regarding our proposed approach to engaging with customers.

28 May
RRG Meeting
We presented an overview of draft terms and conditions.

Stage 1 Stakeholder Engagement Report

Meetings with industrial customers
We held one-on-one meetings with our large industrial customers to provide input into expected demand for natural gas and the services we provide.

25 June
Major Gas Users Forum

1 July
Submitted our RSP to AER

July
Phase #1 Customer Workshops
Understanding Customer Values – 106 participants including business and residential customers and culturally and linguistically diverse communities in 5 online workshops in metropolitan Melbourne and regional Victoria.

12 August
VGNSR Meeting
We presented on preliminary expenditure proposals.

16 August
RRG Meeting

25 August
VGNSR Meeting
New members update.

13 September
VGNSR Meeting
We presented on Customer Workshops to date and planned approach to assist vulnerable customers.

September
Phase #2 Customer Workshops
We validated customer feedback and tested our proposals and ideas in 5 separate online workshops across Victoria.



Victorian Gas Networks Stakeholder Rountable Meeting


Customer Workshops

18 October
Major Gas Users Forum

20 October
VGNSR Meeting

21 October
RRG Meeting

November
Our Reference Services Proposal for Victoria approved

November
Future of Gas Expert Panel
We collaborated with key stakeholders and industry experts to develop a set of future energy scenarios to determine no regrets actions for inclusion in our Final Plan.

17 November
VGNSR Meeting

18 November
RRG Meeting
We presented our preliminary expenditure proposals, our early price modeling and information on how prices are determined through the regulatory framework.

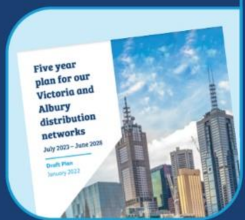
16 December
Combined VGNSR and RRG Meeting
We presented our Draft Plan proposals in detail including:
- Future of Gas
- Capex
- Opex
- Demand
- Capital base

December
Appointment of CCP28

Stage 3
Consultation on our Draft Plan

2022

25 January
Our Draft Plan for Vic 2023 – 2028
We published our Draft Plan for Vic 2023-28.
The Draft Plan was sent to stakeholders and customers.



February- March
Phase #3 Customer Workshops
We presented our Draft Plan and proposal for MGN's Victorian gas network at 5 online workshops across metropolitan Melbourne and regional Victoria.

Priority Service Advisory Panel
We set up an Advisory Panel of community experts to help design a fit-for-purpose priority service program.

2 February
Combined VGNSR and RRG Meetings
We presented on our Draft Plan, Deep Dive methodology and customer workshops.

28 February
Major Gas Users Forum

4, 10, 22, 31 March
Combined VGNSR and RRG Deep Dives
- Future of Gas
- Capex
- Opex

Stage 4
Refinement and Ongoing Engagement

13 May
VGNSR Meeting

17 May
RRG Meeting

May
Independent Review Sessions with VGNSR & RRG

20 June
VGNSR Meeting

22 June
RRG Meeting

We presented on our Regulatory Proposals.

Key

VGNSR Victorian Gas Networks Stakeholder Roundtable	RRG Retailer Reference Group

How have engagement activities influenced and shaped our plans?

All feedback from regular VGNSR and RRG meetings, Draft Plan consultation, meetings with stakeholders and customer workshops has been captured and used to shape and refine our Final Plan.

A high-level summary of customer and stakeholder feedback on our Draft Plan is included in Table 5.2.

A complete set of customer and stakeholder feedback in the Draft Plan is provided in Attachment 5.2. Each chapter of this Final Plan also includes a section on customer and stakeholder engagement.

Feedback tables in each chapter show how we have listened and responded to all feedback received. Final Plan outcomes are also included in tables to demonstrate how engagement has shaped our proposals, and are illustrated as follows:

(green)	Positive/Green – we have support for our proposal
(orange)	Neutral/Orange – we do not have full support for our proposal
(red)	Negative/Red – we do not have support for our proposal
(grey)	Unsure/Grey – further (external) information required before level of support can be decided

Table 4.2: Summary of customer and stakeholder feedback – Final Plan

How we have responded to customer and stakeholder feedback – Final Plan outcomes	Cust	Stkh
Services / Terms & Conditions		
• Stakeholders support our proposal to align our services and terms and conditions across AGN and MGN in Victoria. • Retailers are understanding of our intention to continue to implement our existing credit policy but are keen to continue conversations outside of AA discussions.	N/A	
Future of Gas		
General • Stakeholders acknowledge the current uncertainty around policy in Victoria. Stakeholders find it difficult to accept our future of gas plans as they are subject to change once policy direction becomes clearer. • Stakeholders see natural tensions in our plans between accelerated depreciation, customer connections (growth capex) and hydrogen readiness that are difficult to reconcile.		
Accelerated depreciation • Stakeholders acknowledge that our accelerated depreciation plans have been developed under great uncertainty and expect that we continue to engage on and adapt these plans during post lodgement. • 86% of customers supported our proposal to accelerate depreciation and acknowledged that doing so will protect future price stability, as well ensure equity for those connected to the network.		
Capital Expenditure		
General • Stakeholders have indicated a clear and general preference for discretionary capex to be minimised. • Stakeholders find it difficult to accept some parts of our capex proposal as they are subject to change once policy direction becomes clearer. • 95% of customers are satisfied or very satisfied with the reliability of their gas supply.		
Mains replacement • Stakeholders were clear that preparing our network for renewable gas should not be used as a justification for mains replacement. Stakeholders would like to see our program justified wholly by safety and/or reliability commitments. • Stakeholders keen to see ESV assessment of our Plans. • Stakeholders welcome the reduction in our low-pressure mains replacement program based on draft plan feedback and encourage us to go further, if possible. • 91% customers were supportive of our approach to accelerate the mains replacement program.		
Customer Connections (growth capex) • Stakeholders struggle to support our growth capex proposals given policy uncertainty and question the prudency of continuing to connect customers in this environment.		
Hydrogen Readiness • Stakeholders welcome the reduction in our proposed hydrogen readiness expenditure based on draft plan feedback but struggle to support our plans given policy uncertainty. • 89% of customers support our plans for preparing the network for renewable gas.		
Digital Customer experience • We have received limited feedback on the proposed digital customer experience proposal. Stakeholders are generally supportive of our plans to meet customers' communication expectations, which have shifted to more digital preferences. • 90% of customers supported the proposed digital services package, of which 65% strongly supported.		
IT • We received limited detailed feedback on IT-related aspects of our plans. Stakeholders welcome the benefits of consolidating the IT environments across AGIG.	N/A	
Operating Expenditure		
General • Our plan delivers against customer expectations that customer expectations that current levels of reliability, safety and customers services are maintained, with the inclusion of new and innovative programs. • Stakeholders would like us to minimise expenditure while the future is uncertain.		
Priority Services Program • Most stakeholders support our proposal to introduce a Priority Services Program in Victoria. • Social Service Organisations had a strong preference for the program to be Victoria wide, as opposed to network specific. • Customers strongly supported the idea of new services designed to support customers experiencing vulnerability, noting the impacts of COVID-19 in their communities.		
Renewable Gas Communication and Education • We received mixed levels of support from stakeholders for investment in renewable gas communication and education. Stakeholder felt strongly that communication and marketing activities should not be funded as part of a step change. • 93% of customers support the proposed renewable gas communication and education program, particularly the idea of developing materials that could be used as part of school education.		
Gas Network Innovation Scheme • Stakeholders were not supportive of investment in innovation, and we have therefore not included this initiative as part of this Final Plan. Stakeholders were supportive of this move. • Customers were supportive of this scheme and see innovation as an enabler to transition to cleaner energy.		
Productivity • Stakeholders questioned whether the 0.4% p.a. productivity is sufficiently ambitious, and whether AGN South Australia is a good comparison. We have listened and engaged ACIL Allen to undertake some further analysis which we will use to engage stakeholders post-lodgement.	N/A	
Capex to opex • Stakeholders would like to better understand the drivers of the capitalisation proposal before they can support it.	N/A	
Capital Base		
• We received limited detailed feedback on capital base.	N/A	N/A
Demand		
• We will continue to engage on our demand forecasts during post-lodgement activities, and review these numbers based on any new information (i.e., policy positions). • Some stakeholder questioned whether our Draft Plan numbers were overly optimistic. We have revised down our commercial forecasts in response to this feedback.	N/A	

5.2 Our Customers and Stakeholders

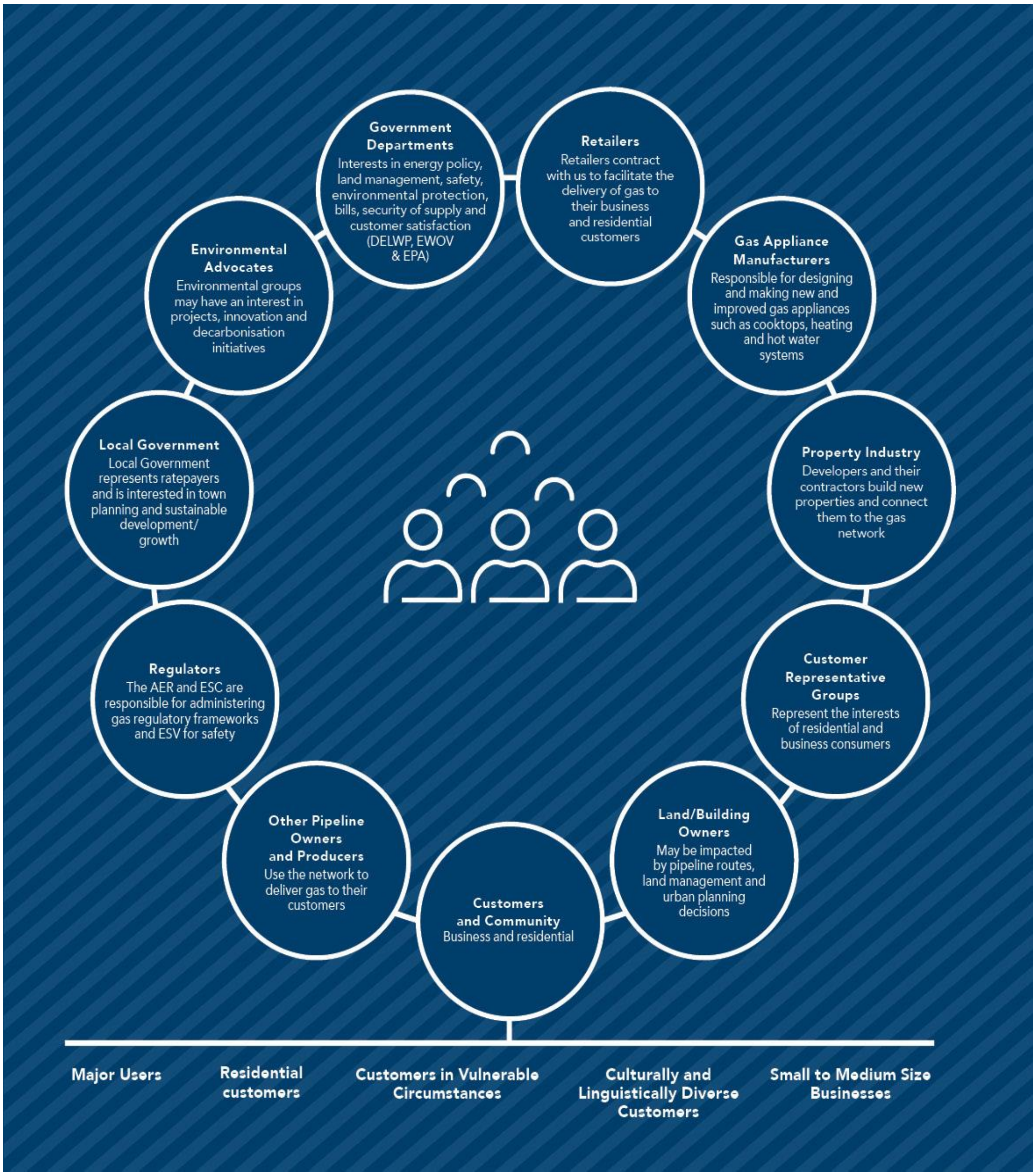
We have identified several stakeholder groups with an interest in how we plan, manage and operate our gas distribution network.

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.

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 5.3.

Figure 4.3: Our customers and stakeholders



5.3 Our Engagement Principles and Approach

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 being accepted by our customers and stakeholders.

We have adopted a series of engagement principles as shown in Figure 5.4. These principles guide how we engage with our customers and stakeholders. As part of stage 1 engagement, we consulted on these principles, and they were endorsed by all stakeholders.

Our approach for this engagement program was to:

- ✓ continue with our four staged approach, which was considered a solid foundation by our stakeholders;
- ✓ seek opportunities to further collaborate with customers where there was an opportunity to co-design;
- ✓ engage more broadly with diverse segments of the community (e.g. CALD); and
- ✓ allow for more iteration of our plans to be developed over time with customers.

As part of our engagement strategy, we set KPIs. Our performance against these KPIs is illustrated in Table 5.3.

Figure 4.4: Our Engagement Principles

Our Engagement Principles

Genuine & Committed

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

Engagement is led from the top

Stakeholder engagement is embedded in our business planning

We look to continually improve

Integrated

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

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

Clear, Accurate and Timely Communication

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

Measurable

We measure the success, or otherwise, of our engagement activities and are accountable for our performance

Seek stakeholder feedback at all key stages of our engagement

Report on feedback

Identify ways to improve our approach

Transparent

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

Publication and consultation of our proposed engagement approach

Online public reporting

We publish and consult on our reports

We report how we used stakeholder insights to inform our plan

Accessible and Inclusive

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

Stakeholder meetings

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

Table 5.3: Our performance against Engagement KPIs

Theme	Key Performance Indicators	Our Performance
Genuine and Committed	• Executive Leadership at 90% of all engagement sessions • VGNSR and RRG Forum access to executive leadership	• More than 80% CEO and 100% executive attendance at VGNSR and RRG meetings. • 50% CEO and 100% executive attendance at customer workshops.
Transparent	• Public disclosure of details about 100% of engagement activities (publish on Gas Matters) • Publish Draft Plan for customer and stakeholder comment	• All engagement resources and materials available on Gas Matters. • Draft Plan was sent to customers and stakeholders via email, it was also published on Gas Matters. • Draft Plan open for a consultation period of 6-weeks. • Stakeholders gave a 100% satisfaction rating for the transparency of meetings and workshops.
Clear, Accurate and Timely Communication	• +80% agreement that the information provided to customers and stakeholders was clear, accurate and timely • VGNSR members +80% satisfaction with how meetings are managed	• 96% of customers satisfied/very satisfied with the workshop presentation and education materials provided by MGN. • 90% of stakeholder were satisfied/very satisfied with the accuracy of meetings and workshops. • Stakeholders gave a 90% satisfaction rating for the relevance and appropriateness of meeting and workshop topics. • Stakeholders gave a 95% satisfaction rating for the clarity and usefulness of information presented at meetings and workshops. • Some retailers expressed a desire for materials to be provided even earlier than they were to allow pre-reading.
Accessible and Inclusive	• 80%+ of VGNSR members, workshop participants and forum members satisfied that the engagement process is accessible and inclusive	• The stakeholder map was developed in consultation with VGNSR members. • 96% of customers were satisfied/very satisfied with the opportunity to contribute their thoughts and opinions. • 96% of customers were satisfied/very satisfied with the overall engagement process. • Stakeholders gave a 90% satisfaction rating for the inclusiveness and accessibility of meetings and workshops.
Integrated and Accountable	• +80% agreement that customers and stakeholders felt that their feedback had been addressed	• 94% of customers supported our Draft Plan and investment proposals, in response to their feedback from workshops #1 & #2. • Stakeholders gave a 86% satisfaction rating for how we acted on their feedback. • Stakeholder expressed their satisfaction with how we responded to their feedback in VGNSR meeting #9. • Stakeholders gave a 95% satisfaction rating for the opportunity to ask questions and seek further information during meetings and workshops.

Our staff were actively involved in our customer and stakeholder engagement program.

Our program of engagement has been led by our executive management team, with our CEO attending >80% of all stakeholder meetings and half of the customer workshops.

All customer engagement sessions were attended by at least one executive team member and more than 20 MGN subject matter experts actively participated in the sessions.

This high level of involvement across all levels of MGN ensured that customer questions could be answered in an open manner, on the spot. This also provided opportunity for our staff to learn directly from customers and better understand their lived experience of our services.

> ***"[I enjoyed] the openness of the team to answer all our various questions – make me feel a part of something important***

> ***"The knowledge of the staff is A+ every question was answered in full***

> ***"So much information and a lot to learn from your workshops***

We received positive feedback about our engagement program and process from customers who attended our workshops.

> ***"The information is so informative, and I enjoyed learning about the gas network in Victoria***

Customers appreciated the opportunity to see how their feedback shaped our Draft Plans.

> ***"Very interactive and informative. I enjoyed seeing our previous workshops come together***

We also received some positive comments from stakeholders with regard to the interactivity and depth of our engagement with them, particularly when dealing with future focused topics of discussion.

> ***"[I enjoyed] the interactive nature of the presentation***

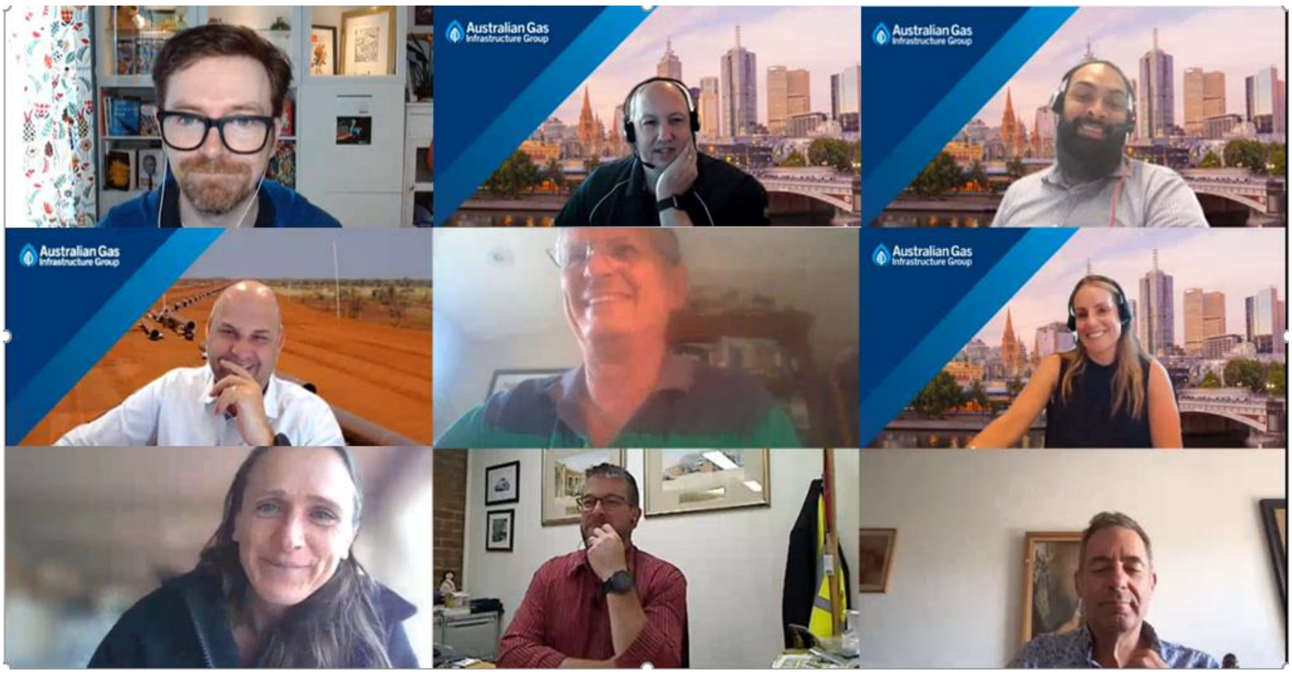
> ***"Thoroughly enjoyed the workshop today and learning about the future of gas. Really fantastic work MGN and feel the benefits would be good for all. Totally support***

5.4 Developing our plans

We delivered a series of engagement activities to inform the development of this Final Plan, which included significant consultation on the Draft Plan published in January 2022.

These activities included three phases of iterative customer workshops, regular VGNSR and RRG meetings and deep-dives, and dedicated co-design with stakeholders.

Image 5.1: Members of the VGNSR enjoying an online meeting



This section covers each of these engagement activities, customer level feedback and how this feedback has shaped our Final Plan.

5.4.1 Direct 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.

The first two phases of workshops led to the development of our Draft Plan, with a third phase of workshops held as part of Draft Plan consultation.

We engaged KPMG to facilitate and document our customer engagement activities. A full report is included in Attachment 5.3.

Customer Workshop Methodology

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

While our preference was to hold the customer workshops face-to-face, owing to COVID-19 restrictions in place at the time, all phases were held online.

We engaged with customers living across three locations on our network with a total of 106 (Phase 1), 92 (Phase 2) and 67 (Phase 3) participants attending across seven dedicated workshops per phase. See table 5.4 for a summary.

Workshops consisted of a mix of residential, small business, 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 Ethnic Communities Council Victoria (ECCV) to hold dedicated workshops with CALD customers in South Melbourne.

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

Table 4.4: Workshop location, customer segments and attendance

Location	Customer Segment	Phase 1 Workshop Attendance	Phase 2 Workshop Attendance	Phase 3 Workshop Attendance	Return Rate (%)
South Melbourne	CALD customers	13	10	9	69
South Melbourne	Residential customers	25	22	18	72
Brighton	Residential and business customers	23	22	12	52
Mordialloc	Residential and business customers	22	17	12	55
Mordialloc	Residential and business customers	23	21	16	70
	TOTAL	**106**	**92**	**67**	**63**

Image: Residential customers from Richmond, AGN staff & KPMG representatives in an online workshop

The objectives of Phase 1 customer workshops were to:

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

Phase 1 workshops were 2 hours in duration and held online. MGN 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.

In Phase 1, customers told us that:

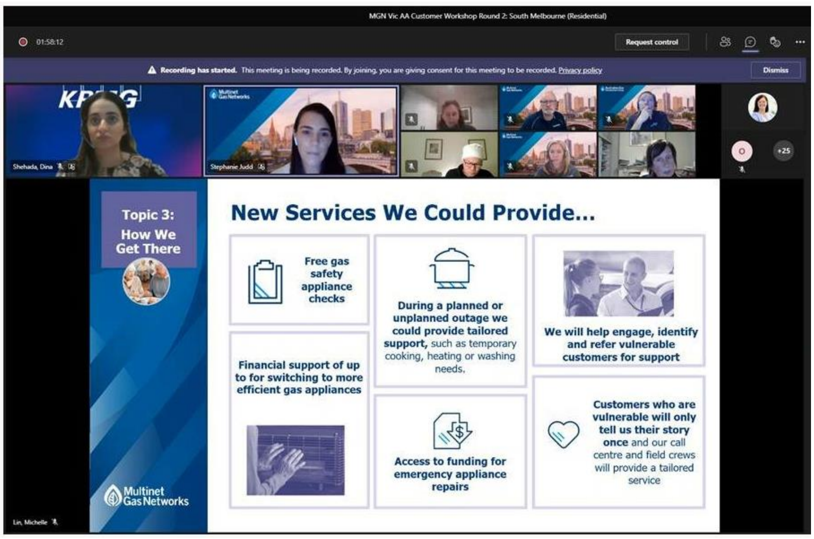
- ✓ Gas supply is an essential service used every day in the kitchen, cooking, hot water, heating in winter and therefore needs to be **reliable** with no interruptions
- ✓ ***"I need gas to feed my family and keep them warm during the colder months"***
- ✓ **Public safety** means responding to leaks 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

"Lots of communities are struggling with bills e.g. the refugee community, they love cooking … how can we prevent bill shocks for them"

- ✓ 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

"It would be useful to know in real time what gas energy is being used"

Image 5.2. Round two customer workshop presentation on MS Teams



Phase 2 Customer Workshops: Objectives, engagement activities, and results

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 MGN's activities
- ✓ Explain how prices are set
- ✓ Explore issues of importance to MGN and customers

- ✓ Test and seek feedback on costed proposals

Phase 2 workshops were 2 hours in duration and included opportunities for open discussion with MGN 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.

New Digital Engagement Practices

Due to COVID-19 restrictions we designed, tested and developed new ways to interact and engage in a genuine way via online workshops.

New online engagement techniques that were highly valued by customers included:

- The opportunity to ask an expert questions any time via the online chat
- Online voting and real time results; and
- Time dedicated in the workshop to complete of feedback surveys
- The use of video content where appropriate

In Phase 2 we presented an early price forecast to reduce prices by an indicative 4%. 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, digital smart metering and consistent pricing.

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:

- ✓ Price and affordability are top priorities customer, and the lens through which they make decisions relating to MGN's services
- ✓ 9 out of 10 customers are comfortable with our proposed approach to accelerate mains replacement while maintaining current levels of safety and reliability
- ✓ On communication, SMS remains a highly valued feature for many, particularly CALD and elderly customers
- ✓ Customer 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 that is accessible and fair is important to all customers
- ✓ Vulnerable and CALD customers have specific needs and require tailored support
- ✓ More than ¾ of customers are comfortable with MGN's approach to shift to consistent pricing

Phase 3 Customer Workshops: Objectives, engagement activities, and results

Phase 3 of customer workshops occurred shortly after we published our Draft Plan. To assist customers, we developed a plain language overview of our Draft Plans and sent them to customers in advance of their workshop. The critical focus of these workshops was to demonstrate how customer feedback from Phases 1 and 2 had shaped our Draft Plan. We also validated and re-tested customer perceptions across key initiatives for further refinement.

In Phase 3 we also introduced our plans relating to accelerated depreciation. We discussed and gathered views on how we should manage the depreciation of our assets during the energy transition. Please see the next page for more detail on how we engaged on this complex topic.

Phase 3 online workshops were 2 hours in duration and included opportunities for discussion. We incorporated videos and surveying to keep it interesting.

Key topics, information presented and insights from Phase 3 are illustrated in Table 5.5. You can also find all workshop materials and reports on our online engagement platform, Gas Matters (agig.gasmatters.com.au)

In Phase 3, we learned that:

- 94% of customers support our Draft Plan and investment proposal.
- A majority of customers (90%) support the revised digital services package, inclusive of the SMS feature at the lower price point.
- 9 out of 10 customers support the plan for

renewable gas communication and education.

- A majority of customers are supportive of innovation funding to trial new ideas and technology.
- Customers were supportive of greater levels of support in other languages and additional services for priority service customers.
- A majority of customers (86%) are comfortable with our plans to accelerate depreciation.

Engaging on Accelerated Depreciation

Customers acknowledged the importance of accelerating the recovery of investments to maintain price stability and equity.

Our intent for this segment of Phase 3 workshops was to understand customer views and collaboratively test the proposed plans to accelerate depreciation. We allocated around 45minutes of the workshop to this topic.

Given the high level of complexity of the topic, and accelerated depreciation being a new concept for many customers, this workshop segment was structured in four parts. There were numerous pulse checks and opportunities for customers to ask questions.

The four-part approach was structured as follows:

1

Part I: Discussion on how price is calculated; introduction of the concept of 'depreciation'; utilisation of home loan analogy to support customer understanding of theoretical concept
Checkpoint: *Does the concept of depreciation makes sense? Do you have any questions?*

2

Part II: Discussion on the future of gas, and current uncertainty
Checkpoint: *Do you have any thoughts on the future of gas?*

3

Part III: Introduction of the concept of 'accelerated depreciation'; discussion on the risks/implications; discussion of the proposed plans
Checkpoint: *Does the concept of accelerated depreciation makes sense? Do you have any questions?*

4

Part IV: Discussion and recap on the proposed plan to accelerate depreciation
Checkpoint: *Are you comfortable with our draft plans to accelerate depreciation? Do you have any questions?*

Table 4.5: Customer workshop summary feedback

Theme	Engagement Activity	Key Insights and Results
Get the basics right	**Phase 1 Customer Workshops**	

	• 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.
		✓ After price, reliability and safety are the top two priorities for customer.
		✓ 95% of customers are satisfied or very satisfied with the reliability of their gas supply.
		✓ When communicating with MGN, 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.

	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 activities:
	  • How comfortable are you with MGN'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)
		✓ 91% of customers supported MGN's proposed approach to accelerate the mains replacement program, with 9% asking for more information to be able to make a decision
		✓ 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.
		✓ 56% 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.

	Phase 3 Customer Workshops	

	• We presented our draft plan proposal to maintain current levels of safety and reliability
	• We presented our digital services package, offering customers more channels and more choice at $1 p.a.
	• Engagement activities:
	  • Do you have any additional comments on our safety and reliability program?
	  • To what extent do you support our proposed digital services package?
		✓ Customers value their gas supply and expressed that they were comfortable with our plans to maintain current levels of safety and reliability.
		✓ 90% of customers support MGN's revised digital services package, inclusive of SMS, at the $1 price point.

Table 5.5: Customer workshop summary feedback (cont.)

Theme	Engagement Activity	Key Insights and Results
Focus of 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 discussed innovation for a range of purposes (e.g., metering, trialling new technologies, investing in sustainability).
	• Engagement activities:
	  • Is it important to you that MGN supplies cleaner energy to customers? Why or why not?
	  • How areas of innovation do you think are important?
		✓ Clean energy and reducing carbon emissions is an imperative for the majority of customers.
		✓ 90% of customers view climate change and reducing carbon emissions as important or very important.
		✓ 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 activities:
	  • Are you comfortable with our proposed approach to preparing our networks for renewable gas? Do you need more information?
	  • Should MGN invest in a standard, medium or broad renewable gas communications campaign? Why? (3 options tested)
		✓ 89% of customers support MGN's proposed approach to preparing our networks for renewable gas.
		✓ 80% of customers supported increased investment ($2-3 p.a) beyond MGN's existing activities on more renewable gas communications and education activities.
		✓ 46% of customers supported a very broad communications campaign noting the importance of school and community education.

	Phase 3 Customer Workshops	

	• We re-capped our plans to undertake no-regrets actions to prepare our network for renewable gas
	• We presented our plans to build awareness around renewable gas and build customer confidence at $2 p.a.
	• We presented our plans to introduce an innovation allowance scheme a range of price points (3 options tested)
	• Engagement Activity:
	  • Do you have any additional comments on our plans to prepare the network for renewable gas?
	  • To what extent do you support our proposed plans for renewable gas communications and education?
	  • Which level of innovation funding do you think offers best value?
		✓ Customers value the continued availability of gas, and support MGN preparing the network for renewable gas on its journey for decarbonisation.
		✓ 93% of customers support our plans to introduce a renewable gas education and communication campaign.
		✓ 90% of customers are supportive of innovation funding to trial new ideas and technology
		✓ A majority of customers believed innovation funding around $1.50 - $2 p.a. offered best value.

Figure 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?
		✓ 50% of customers ranked price as their number one priority.
		✓ 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.

	Phase 2 Customer Workshops	

Provide affordable and accessible services	• 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)?
		✓ 92% 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.
		✓ Customers want to better understand and increase efficiency of their daily usage.
		✓ 77% of customers were agreed that MGN should move to a consistent price, rather than a seasonal price. 18% asked for additional information to inform their decision.
		✓ Customers agreed that consistency when it comes to pricing makes it easier to manage bills throughout the year.

	Phase 3 Customer Workshops	

	• We presented an updated price and our forecast price reduction.
	• We presented our plans to support customers in other languages and provide additional services for priority customers
	• We presented our proposed plans to accelerate depreciation
	• Engagement Activities:
	  ◦ Do you have any comments on the metering and priority services program we have discussed?
	  ◦ Are you comfortable with our draft plans to accelerate depreciation?
		✓ Customers expressed positive sentiment towards support in other languages and additional services for priority services customers.
		✓ Customers are in favour of the proposed Priority Services Program
		✓ 86% of MGN customers were comfortable with our plans to accelerate depreciation.

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 Energy Users Association of Australia (EUAA), Ai Group and Major Energy Users (MEU) and their members to deliver three forums in the lead up to the publication of this Final Plan.

These forums focused 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 MGN 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 of the gas network and the potential implications for them
- ✓ They would like MGN to continue to grow the network

We held 3 sessions with the Major Gas Users Forum over an 18-month period leading into this Final Plan.

5.4.2 Stakeholder Roundtables, Meetings and Forums

Victorian Gas Network Stakeholder Roundtable (VGNSR)

The VGNSR is made up of customers and other stakeholders advocates who represent a wide range of gas end-users, including customers in vulnerable circumstances, CALD 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)
• St Vincent de Paul
• 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)

Image 5.3: A face-to-face meeting of the VGNSR in early 2021

The role of the VGNSR is to:

- ✓ Provide input and feedback to inform the development of our plans, working towards our plan objective of 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 is kept up to date on all our engagement activities, and we extend an open invitation to its members to observe these. We also report back to the group on the outcomes and key highlights of all our engagement activities.

The VGNSR has met 10 times between March 2021 and the development of this Final Plan. We anticipate that we will meet a further 2 – 3 times during post-lodgement engagement.

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

We provided early and ongoing price modelling updates to members at our meetings as part of our 'no surprises' approach to engagement which was welcomed by stakeholders.

We presented our draft expenditure proposals to VGNSR members in December 2021, and again in May 2022.

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.

Retailer Reference Group (RRG)

The 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 10 times in the lead up to this Final Plan. Table 5.8 below provides a summary of key topics and information presented at RRG meetings.

Draft Plan Deep-Dive Workshops with the VGNSR and RRG

We ran a series of deep-dive workshop on key elements of our Draft Plan as part of our engagement program with members of the VGNSR and RRG.

These deep-dive workshops were designed for deep level exploration of our plans relating to the future of gas, capital expenditure and operating expenditure.

In total, we held 4 deep-dive workshops in March 2022 that were 2-hours in duration. We also met with several stakeholders in a 1:1 format following some of these sessions to answer their additional questions and share details of our Future of Gas modelling.

Participants were provided a copy of our Draft Plan and well as slide packs ahead of each session to aid discussion. Table 5.9 below provides a summary of key topics and information presented at the deep dive workshops.

The following observations emerged from the deep-dive workshop process:

- Acknowledgement that our Final Plans have been developed in a period of policy uncertainty.
- A clear need to understand our plan narrative, and how we are balancing current network needs with future uncertainty.
- Interest in how intergenerational equity issues should be considered.
- General preference that all non-discretionary expenditure should be limited in the upcoming regulatory period.

At our VGNSR and RRG meetings in May 2022 we shared how we are responding to all feedback on our Draft Plan and tested their level of support for this Final Plan.

KPMG's Independent Review

To ensure that we (i) accurately interpreted stakeholder feedback on our Draft Plans and (ii) adequately responded and adapted our plans in response to this feedback (as presented in May 2022 VGNSR & RRG meetings), we appointed KPMG to facilitate an independent review on our behalf.

Specifically, members of the VGNSR and RRG were invited to optional sessions whereby the KPMG team captured their feedback and level of support for our Final Plans. These KPMG independent reports can be found on our Gas Matters website (agig.gasmatters.co.au).

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: o Major Gas Users Forum o Phase 1 Customer Workshops o 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 • Phase 2 customer workshops overview • Future of gas scenario modelling update • Stakeholder engagement activity update • AER presentation on information paper
Meeting #7 (December 2021) **Joint with RRG**	• 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
Meeting #8 (May 2022) **Joint with RRG**	• Draft Plan overview • Deep-Dive methodology • Stakeholder engagement update	• Draft Plan overview • Deep-Dive methodology • Stakeholder engagement update
Meeting #9 (May 2022)	• Update to our Plans • Post-lodgement engagement	• How plans have been adapted to accommodate customer and stakeholder feedback • Stakeholder engagement update
Meeting #10 (June 2022)	• Our Final Plans to be submitted on 1 July • Post-lodgement engagement	• Overview of our Final Plans • Stakeholder engagement update

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) **Joint with VGNSR**	• 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
Meeting #8 (May 2022) **Joint with VGNSR**	• Draft Plan overview • Deep-Dive methodology • Stakeholder engagement update	• Draft Plan overview • Deep-Dive methodology • Stakeholder engagement update
Meeting #9 (May 2022)	• Updated Terms and Conditions • Update to our plans • Post-lodgement engagement •	• Updated Terms and Conditions and how we responded to retailer feedback • How plans have been adapted to accommodate customer and stakeholder feedback • Stakeholder engagement update
Meeting #10 (June 2022)	• Our Final Plans to be submitted on 1 July • Post-lodgement engagement	• Overview of our Final Plans • Stakeholder engagement update

Table 5.9: Draft Plan Deep-Dive Workshops

Meeting #	Key Topics	Summary of Information presented
Deep-Dive #1	• Future of Gas (A)	• Future of Gas Expert Panel • Modelling update • Customer connections • Potential policy changes • DELWP & Gas Substitution Roadmap
Deep-Dive #2	• Operating Expenditure	• Opex forecasts • Priority Services Program • Gas Network Innovation Scheme
Deep-Dive #3	• Capital Expenditure	• Capex forecasts • Safety and reliability • Growing the network • IT • Other capex
Deep-Dive #4	• Future of Gas (B)	• Future of Gas Expert Panel • Future of Gas modelling assumptions • Accelerated depreciation • DELWP Gas Substitution Roadmap

Image 5.4: A hybrid (face-to-face and online) meeting of the VGNSR in May 2022

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 met with property developers in June 2021 and again in May 2022. 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. The Master Plumbers Association were also a member on our VGNSR. Gas plumbers are particularly interested in understanding our plans to safeguard the future of the gas networks, and any related government positions / policy.

5.4.3 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 (see table 5.10 for details on Panel members).
The scope of the Expert Panel was to:

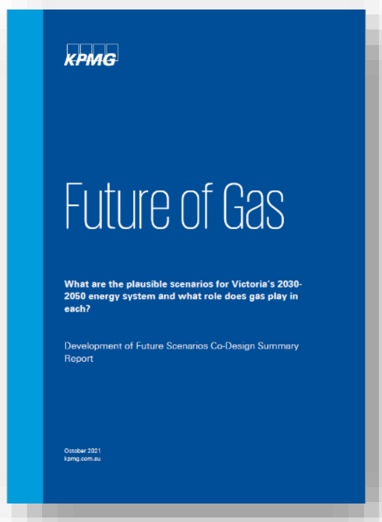
- Co-design four plausible scenarios for the future energy system (2030 – 2050), and the role of gas in each scenario
- Produce a qualitative description of the drivers for each scenario
- Ensure the output produced represented four plausible scenarios rather than predications or preferences for the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

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

Table 5.10: 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



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.

At the end of the Future of Gas co-design workshops we asked members to complete a short online feedback survey. They agreed unanimously 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.

5.4.4 Priority Service Advisory 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 MGN customers but wanted to ensure that it was fit-for-purpose for those 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, 92% of customers in our customer workshops said that providing dedicated services to vulnerable customers was important or very important.

Table 5.11: Priority Services Program Advisory Panel

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

To design a program that truly delivers on 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. Figure 5.7 provides a summary of members on the Panel.

In November and December 2021, we held the first two workshops with the Advisory Panel. 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 held a third, and final workshop, with the group in March 2022 to further refine our proposed program. We worked closely with the group to prioritise and align the program across all Victorian gas networks, and ensure that the program would deliver benefit to those experiencing vulnerability

You can read more about our proposed PSP in Chapter 7.

5.4.5 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 AGN, 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 Gas Network Innovation Scheme (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.

5.4.6 Public Submissions on our Draft Plan

We received public submissions on our Draft Plan from the Brotherhood of St Lawrence and the Energy Users Association of Australia.

All submissions are included in Attachment 5.4. We have incorporated their feedback into the development of this Final Plan, and the summary feedback tables provided in Attachment 5.2.

5.4.7 Consumer Challenge Panel

The AER's Consumer Challenge Panel (CCP28) was appointed in December 2021. Since then, we have been activity engaging and meeting with the Panel.

CCP28 were able to attend and observe the tail end of our Stage 2 engagement program. Specifically, they observed some of our Phase 3 customer workshops, deep-dive workshops, independent reviews and RRG/VGNSR meetings #7, #8 and #9.

5.5 Conclusion

Almost 2-years ago we set out with the objective to develop a Final Plan which delivers for current and future customers, is underpinned by effective stakeholder engagement and is capable of being accepted by our customers and stakeholders.

We received positive feedback about our engagement program from customers and stakeholders. More than 96% of customers said that they were satisfied with the opportunity to contribute their thoughts and feeling. Stakeholders particularly liked our joint engagement approach, ultimately streamlining how they engaged with all Victorian Gas Networks in the development of our Final Plans.

We have undertaken a wide range of engagement activities to support the development of this Final Plan, including direct customer and stakeholder engagement. This input has shaped and informed the development of our Final Plan over time. As noted in this chapter, 94% of customers support our plans.

We have developed our plans in an environment where there is considerable uncertainty over the role of gas in a low carbon future. Many stakeholders have found it difficult to accept our plans given that they might be subject to change once policy direction becomes clear. They are keen to see the release of the Victorian Government Policy and our response to this direction, some describing the situation as being in a 'holding point, rather than a landing point' when it comes to acceptance of our plans.

With that, we are committed to continued and on-going engagement with customers and stakeholders during post-lodgement and ahead of the AER's Final Decision.

A complete set of customer and stakeholder feedback during the engagement program, and how this feedback has been incorporated in the Final Plan is provided in Attachment 5.2.

6 Future of Gas

The energy sector is facing significant change and uncertainty as it transitions to net zero. With long lived assets, we need to start planning now to offer our customers flexibility in the future, keep prices stable and reduce risk.

IN THIS CHAPTER:

- **The challenges we face will require flexibility; for us and for our customers.**
- **Accelerating some depreciation now provides some of this flexibility, enables a smoother transition to net zero and price stability as the energy sector transitions.**
- **We need to plan using a robust and transparent methodology.**
- **This chapter outlines the approach we have taken to address the uncertainty and change in the sector, and in particular our accelerated**

6.1 The energy sector is rapidly changing

The energy sector is going through fundamental change. The future direction of the sector is subject to considerable uncertainty. The affects are being felt now, driven by four key factors:

- Government policy – from local to Federal government and appliances to carbon targets.
- Technology – particularly renewable electricity which is changing the way energy is produced and consumed, including the creation of "prosumers".
- Markets – technological and policy change create new market opportunities for a wide variety of new services; energy is unlikely to remain as the current gas/electric network duopoly.
- Electricity prices – as the need to reflect cost structures in electricity becomes more important. This affects us because we compete with variable electricity charges.[3]

Gas has always been a fuel of choice and competed with electricity. However, the future will likely present a markedly different competitive environment with many players offering a wide range of competing and complementary services. The role gas networks will play in that future is uncertain.

The transition of the energy sector to net zero will take time, but the risks and uncertainties it is creating, particularly for an industry with very long-lived assets which customers pay back over decades, are here now.

It is important to consider the impact of the change and uncertainty in the energy sector not just over the next AA period, but over the longer term. The earlier we start to address the risks presented, the smoother the transition to net zero will be. In this chapter we explain our

[3] See AER, 2022, *Regulating Gas Pipelines under Uncertainty*, pp58-9 for more on sectoral interdependencies.

approach to addressing these uncertainties and risks in the next AA period, made up of three key actions:

- Accelerating a modest amount of depreciation (5% of the RAB) in the next AA period. This approach is critical to ensuring price impacts on customers of the transition are minimised over the longer term, that customers have flexibility, options are kept open in the future and risks of asset stranding are mitigated. This chapter and its attachments set out in detail the approach that underpins our proposal.
- Hydrogen readiness capital expenditure - keeping options open for customers and providing the ability to respond rapidly as the sector transitions. Our detailed proposal is set out in chapter 9 of this Final Plan.
- Prudent and efficient network growth providing better price outcomes for customers and flexibility to transition to renewable gas. This is also addressed in more detail in chapter 9.

Each action gives us flexibility in a wide range of future outcomes and starts to mitigate the risks of uncertainty.

6.2 Regulatory framework

The key action we propose in the next AA period is to accelerate depreciation. NGR 89(1)(a) provides that a depreciation schedule should be developed:

a) so that reference tariffs will vary, over time, in a way that promotes efficient growth in the market for reference services; and

b) so that each asset or group of assets is depreciated over the economic life of that asset or group of assets; and

c) so as to allow, as far as reasonably practicable, for adjustment reflecting changes in the expected economic life of a particular asset, or a particular group of assets; and

d) so that an asset is depreciated only once; and

e) so as to allow for the service provider's reasonable needs for cash flow to meet financing, non-capital and other costs.

The key criteria for our accelerated depreciation proposal are (a) and (b). Our depreciation proposal is consistent with the AER's previous approach to depreciation, in a way that takes into account the change in circumstances in the industry.

6.3 Customer and stakeholder engagement

We have consulted extensively on our proposal in relation to the future of gas, in particular accelerated depreciation. We have summarised below some of the feedback we received and our response to it. These issues are complex and will likely be a key part of the regulatory conversation at least until the current uncertainties in the energy sector become clearer. We note the following outcomes from our consultation that support our proposed approach:

- Customers who attended our workshops did understand what we are trying to achieve by accelerating some depreciation now and were supportive of it.
- As we went through the process, more stakeholders came to a better understanding of what we are trying to achieve. This did not necessarily mean they agreed, however, understanding is a key first step in the ongoing debate on this topic as we move forward.[4] The key stakeholder concern was around how accelerated depreciation sat alongside other initiatives, such as hydrogen readiness and customer growth, and difficulties assessing these initiatives given the current uncertain policy position.
- Most stakeholders trusted the robustness and transparency of the modelling framework. More particularly, most felt that the framework was sufficiently robust that the AER would be able to ensure that our accelerated depreciation proposal was reasonable and supported by sufficient evidence. This, again, is a key part of the debate.

A summary of what we heard and our responses are set out in table 6.1 below.

6.4 The need to address change and uncertainty

The AER recognised the uncertainty faced by gas networks in the future and the need to start considering the longer term impacts in its *Regulating Gas Pipelines under Uncertainty* information paper (see here, in particular pp 3-13). We discuss the topics addressed in the information paper in significant

[4] See AER, 2022, *Regulating Gas Pipelines under Uncertainty*, p(vii)

detail in Attachment 6.1, but address the key themes below.

Firstly, it is important to understand what the risks are and how they impact us and our customers. The AER refer to "long-term demand risk".[5] This is different to the demand risk that is usually considered in the regulatory context. In assessing AA proposals, the AER has, traditionally, considered demand over the next five years of the AA period, with a focus on "expected" demand and perhaps a range of uncertainty around these estimates. Demand further into the future has not been commonly considered.

By contrast, "long term demand risk" looks out much further than the next AA period. Over a longer time horizon, demand does not simply have a wider band of uncertainty around a central forecast, but could change fundamentally, dependent on the view of the future. In particular, the direction of growth is unknown. There is a possibility that demand could continue to grow as it has in the past, could flatten out or begin declining, possibly at rapid pace, and each possibility is driven by changes in the energy sector, which is evolving in a way which cannot yet be predicted.

A rapid decline could occur if:

- Customers become much more price sensitive than they are today.
- Lower cost substitutes emerge.
- The sentiment towards natural gas changes.

As the AER notes in its information paper, a material decline in demand for natural gas

Table 6.1: Customer insights on the future of gas

What we heard	Our response
• While stakeholders agree on the need to reduce carbon emissions and that a reduction in natural gas consumption will play a role in that, they have differing views on how we should be preparing for the future and who should bear the costs. • Most customers who participated in our workshops feel positively about the future of renewables, and renewable gas. • 89% of customers indicated that they were comfortable with our plans to prepare the network for renewable gas. • Customers stressed the importance of keeping energy prices sustainable and stable in the pursuit of decarbonisation to ensure equity for all customers. • 86% of customers in our workshops supported our proposal to accelerate depreciation and acknowledge that doing so will protect future price stability, as well as ensure equity for those connected to the network. • Other stakeholders said that they considered there is a tension between accelerated depreciation on the one hand and increased capex and hydrogen readiness expenditure on the other hand that is difficult to reconcile. • Given the current policy uncertainty, stakeholders expressed an inability to decide, at this time, whether they could support accelerated depreciation, together with growth capex and investment in hydrogen readiness. • Retailers noted that the retention of accelerated depreciation in our Final Plan as a core issue. • There were broad views that the four scenarios developed by the Expert Panel are not equally likely and that we should put more effort into preparing for others. • Stakeholders want to see our response to final policy direction by the Victorian Government, before they can accept our Plans as they relate to the future of gas.	Our accelerated depreciation proposal is new, not only in respect of making a change to depreciation (which has rarely happened over the past 20 years) but also in respect of the need to address the uncertainty faced by the industry at the moment. This requires some different thinking than is traditionally the case for a regulated business. We acknowledge the challenges our stakeholders felt in considering our Plans in the current uncertain environment. However, it is necessary for this Final Plan to balance the need to continue to deliver safe and reliable services to our customers over the next AA period, while also starting to address the evolving risks as the energy sector transitions to net zero. In particular: • We propose to start taking small steps now (eg-modest acceleration of depreciation) to ensure the transition to a net zero future is smooth. The earlier these risks are addressed, the better we are able to manage the transition in the long-term interests of customers. This includes ensuring customers are not faced with significant price volatility and asset stranding risk. • Ensure options are kept open for the future, for example, small amounts of expenditure to enable use of networks to transport renewable gases and ensuring cost competitiveness in the future. We consider our Plans reflect an appropriate way to balance these issues. We also consider we have used the best available information at this time to inform our Final Plan. We will continue to engage on this topic, including after the publication of the Gas Substitution Roadmap
Final Plan Outcome	
We have maintained our accelerated depreciation proposal for a range of reasons, including to ensure the smoothest transition to a low carbon future.	

[5] See AER, 2022, *Regulating Gas Pipelines under Uncertainty*, p(x).

distribution services would have a number of adverse impacts:

- Less customers who are left to share the fixed network costs.
- Past efficient expenditure will be disproportionally borne by future gas customers or those least able to leave.
- Investors are unable to recover their investment, leading to asset stranding risk.
- Price volatility, uncertainty, reducing demand and the resultant higher prices leads to a 'death spiral' or further declines in demand.

These outcomes are not in the long-term interests of customers and are not consistent with the achievement of the national gas objective.

For us, the end result of a death spiral demand reduction is the loss of whatever assets have not been recovered; referred to as economic asset stranding.[6] However, before we get to this point, our customers may endure many years of rapidly rising prices; particularly those least able to leave the network.

It is this customer impact which regulatory decisions (and businesses) seek to avoid. While the pathway to net zero and how and when demand for natural gas services will be impacted is unclear, what is clear is that demand risk exists in the future and that those risks, if not addressed, will give rise to adverse outcomes for customers and investors. The risk can be mitigated by taking measured, low cost actions today in the long term interest of customers.

In this context there are a number of key considerations which inform our proposal.

Firstly, it is important to note that policy (which might support or hinder our role in a net zero future) is not static. The Victorian Government's Gas Substitution Roadmap, which is currently unavailable, may give some clear direction, but it may not. In any event, it is highly unlikely to reflect the final policy position. Rather, policy is likely to evolve through time as more information becomes available. Risk and uncertainty will likely remain for a significant period following the publication of the Roadmap.

Secondly, avoidance of adverse outcomes for customers is a key consideration for us, as is ensuring customers have choice in the future and that the regulatory outcomes do not foreclose options. We are not planning for a steady decline of our business. If we were, that would require acceleration of in the order of over 50% of our RAB in the next period (and this would not remove all asset stranding risk) rather than the 5% that we are proposing.

We are optimistic about the future role gas distribution networks can play transporting renewable gas and are actively pursuing those opportunities. But we will need to be cost competitive in the future to play a role.

Our proposal to moderately accelerate depreciation now is one part of a package of options which seeks to give us and our customers flexibility across a wide range of potential future outcomes.

Thirdly, the risks and uncertainties we are seeing now in the market and in the policy landscape are not risks and uncertainties reflected in regulated prices. They are not included in the WACC, they are not, yet, included in the economic lives of our assets, nor in any of the other building blocks.[7] If we do nothing, they will remain unrecognised and unaddressed in the regulatory framework, but they will still exist in reality.

Fourthly, although the national gas objective (NGO) and the phrase "long term interests of consumers" has been considered a lot in recent years, it has never been more important than in the dynamic and uncertain world we are facing. In particular, the NGO requires networks and the AER to look well beyond the time horizon of the next AA and consider longer term demand impacts (see above).

Regulatory decisions made now can play a key role in looking beyond the immediate needs and options of investors and current customers and ensure that:

- options for future customers remain open
- the transition to net zero and the impact on customers is smooth
- price volatility is minimised.

The New Zealand Commerce Commission has recently recognised this, allowing accelerated depreciation for New Zealand gas distribution networks as well as new customer growth. Other regulators, including the AER have made similar decisions.[8]

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[6] See AER, 2022, *Regulating Gas Pipelines under Uncertainty*, p25.
[7] See AER, 2022, *Regulating Gas Pipelines under Uncertainty*, p28.
[8] The NZ decision is available here. For other jurisdictions, see AER, 2022, *Regulating Gas Pipelines under Uncertainty*, p40-42.

6.1 How we propose to respond

The changes we and our customers face moving forward are very different from those faced in the past. We have scope to ensure the risks that come with the uncertainty of the future are addressed and managed, if we act early. As the AER notes, the longer the time we have to make adjustments (such as accelerating depreciation) the smoother the depreciation profile and price impacts will be.[9] Delivering stable prices for customers through time provides the greatest opportunity to meet the national gas objective.

However, failing to act at all, or taking actions which do little to respond to the future uncertainty and relevant long term demand risks could create a path dependency, close off future options for customers and give rise to price volatility and asset standing risk. This makes for a difficult challenge.

A core tool to help address these challenges is the creation of options. These are relatively low-cost actions which reduce barriers to the flexibility which is desirable to face the future. By way of an example, the legislative framework does not currently allow gas distribution networks to carry hydrogen in all jurisdictions, and changing legislation, although it is relatively low cost, takes time. The AEMC, among others, has accordingly started this process of legislative change now, rather than waiting until the future of hydrogen is clear. This creates an option for us to move quickly to satisfy customers' needs as the transition evolves.

The creation of options is not typically part of a regulatory tool-kit, although it is starting to be considered as regulators and networks make more use of scenario planning. The regulatory framework was not designed with the kinds of uncertainties and challenges that option creation can address in mind.[10]

In a competitive market (which the regulatory framework seeks to replicate) it is standard practice. If a firm in a competitive industry waits until all uncertainty has been resolved before investing, it will find its potential market share has been taken by a more nimble rival. In part, our focus on developing flexible options is a consequence of us responding to the competitive pressures we can already see coming.

There are three key actions (options) which help give us and our customers flexibility, and which form part of our Final Plan.

The first of these is accelerated depreciation. The amount we propose is far less than what would be required if we were planning for a future that did not see gas distribution networks playing a role in the net zero energy sector. However, it is sized correctly to provide options and flexibility to us and our customers, while also reducing the risks that will arise if there is a rapid decline in demand and, for example, electrification becomes the certain future.

Importantly, the Final Plan as a whole, including the accelerated depreciation proposal, delivers a price cut to our customers and ensures more stable prices in the future by starting to reduce the amount of investment required to be recovered in future periods. We recognise the importance of affordability and price stability in the uncertain environment we and our customers face. Our approach has been designed such that it can be adjusted as the future unfolds. Customers, over the life of the asset, will have paid not one dollar more for its use.

The second action we propose is a very small amount of capital expenditure (some $9 million) to address network issues that would prevent even low blends of renewable gas. The proposed expenditure has been moderated since the Draft Plan and relates to, for example, updating procedures and replacing any identified equipment incompatible with hydrogen. This gives us the flexibility to increase hydrogen in our network if it is successful.[11] We are also proposing a small amount of incremental expenditure on renewable gas communication and education programs (see Chapter 8). It is a prudent and efficient step for a business facing a major transition to communicate and educate customers about the future options.

The third action is prudent and efficient network growth. Setting aside the fact that we must, legally, connect new customers where it is efficient to do so, not connecting new customers will only increase risk and reduce flexibility for customers.

If a new connection is less costly to the network than the average of existing connections, then adding them to the network brings down price, which in turn lowers demand risk. This analysis holds under various future scenarios, for example, even

[9] See AER, 2022, *Regulating Gas Pipelines under Uncertainty*, p44.
[10] See AER, 2022, *Regulating Gas Pipelines under Uncertainty*, pp57-64 for a much wider discussion on issues our future challenges pose for the regulatory system.
[11] See AER, 2022, *Regulating Gas Pipelines under Uncertainty*, p52.

where asset lives are shortened due to electrification (see Attachment 6.1). More importantly, by virtue of a connection charge,[12] we can ensure that each new connection costs less than the existing average, and therefore lower prices and risks for customers. Doing so also increases flexibility; it is much cheaper to connect a new sub-division now than it is to go back and dig up by then established streets in future to give customers the option of hydrogen.

As Incenta point out in their expert report:[13]

> *It would be logical for the Victorian Networks to continue connecting customers notwithstanding the future risks to the sector, provided that the incremental cost of connecting a new customer is below the average cost of supply. Under this condition, new customers put downward pressure on prices and so act to reduce the risk of asset stranding.*

Our customers also continue to choose gas to heat their homes and businesses and expect to be able to continue to use gas now and into the future.

We appreciate that there can and should be a debate about the scale and nature of options that then translate into prudent and efficient actions within the regulatory framework. However, ignoring future possible scenarios and waiting for certainty gives rise to the risks we have discussed above and is not in the long term interests of customers. Taking small steps now to address these risks and provide flexibility to adapt as the future becomes more certain is in our view the appropriate way to address the new challenges we face.

It also is important that the regulatory process understands and recognises these risks and takes action, not just in the long term interests of customers, but also to enable service providers to attract the efficient investment necessary to operate. This is particularly important for credit rating agencies and financiers more broadly and to ensure networks are able to fund operations consistent with the benchmark assumptions.

6.5 Accelerating depreciation

We now turn to our approach to determining how much and what kind of accelerated depreciation we consider is required. Our approach involved a lengthy development process, involving a great deal of detailed stakeholder input and consultation (see Chapter 5 and Attachment 6.1) and an expert panel who developed four future scenarios underpinning our analysis. It also benefited from early and quite detailed consultation with the AER. We provided copies of our models early in the process and benefited greatly from suggestions from the AER in improving them.

More detail on our process is provided in Attachment 6.1. We provide a summary of our approach, and its results, below.

Our approach to determining a prudent change to depreciation

The core in terms of economic theory for our modelling is a paper by Crew and Kleindorfer (1992) which looks at appropriate depreciation schedules in situations where a current monopolist is likely to face competition in the future as the price of substitutes fall. This model was largely implemented in our recent Access Arrangement proposal for our DBP transmission pipeline, which was accepted by the ERA.[14]

Since distribution has a large number of small consumers instead of a small number of large consumers, we have had to adapt the model we built for a transmission network to the distribution context, but it still operates in basically the same way; consumers respond to falling prices of substitutes through time, and we adapt our prices to these forces using the depreciation schedule.

The model we use consists of a consumer choice model and a simplified building block model (see Attachment 6.1 for more detail).

In the consumer choice model, there are a number of customers (with certain characteristics

[12] Note that there are restrictions in Victoria on connection charges, which can only recover the excess above the current average, without taking into account asset stranding risk. Some change to this Victorian Government process would be required to allow us to take asset stranding risks into account in connection charges, but that sits outside the AA process. See AER, 2022, *Regulating Gas Pipelines under Uncertainty*, p57 for the AER's views on connection charges.
[13] See Attachment 6.4, [8].
[14] See *Crew, M and Kleindorfer, P, 1992, Economic Depreciation and the Regulated Firm under Competition and Technological Change, Journal of Regulatory Economics, 4(1), 1992, 51-61 (available here)*, and note that we focussed on how much depreciation ought to be increased now, rather than working out, as the paper does, the last point at which the regulator could act.

driving choice) who have appliances due for replacement each year and who go to market to compare the purchase and operating costs of new electric and gas replacements. One part of this decision is the gas (or hydrogen) price, which comes each year from the simplified building block model.

The consequences of that choice are reflected in realised (in the consumer choice model) demand, which then goes back to the building block model to forecast opex, capex and price for the next period. That new price goes back to the consumer choice model and the process starts again.

Once the model is run for a period of 80 years (to 2100), we can compare the stream of costs from the simplified building block model with the series of revenues (price times demand) from the consumer choice model. If they are equal in an NPV sense, then nothing needs to be done. If the costs are greater than revenues, then the lever we pull (in the building block model) is to change the pattern of depreciation to bring forward more of the depreciation of the longest-lived assets in the RAB.[15]

This works because the relative difference between gas and electricity prices now are such that an increase in gas price will elicit only a small response; much less than the larger (and opposite in direction) response in future as customers face lower prices. There is a natural limit in the model because too much acceleration of depreciation will cause prices to rise too much too soon, and precipitate precisely the kind of death spiral demand reduction we discuss earlier. In effect, the exercise seeks to ensure we can meet our competition and keep our customers, just like any competitive business would.

Given the high levels of uncertainty about the future, it is not appropriate to run the model in some "most likely" scenario, or even to combine scenario outcomes in some kind of weighted average manner. Rather, we use the model to test depreciation profiles across the four scenarios developed for us by the independent panel of experts,[16] and accept the depreciation profile which delivers the most stable prices across the largest number of scenarios. This is emerging as a form of best practice in environments of

Table 6.1: Scenarios for Future of Gas modelling

Scenario name	Scenario description
Electric Dreams	Characterised by deep electrification underpinned by strong market driven growth of renewables, investment in system flexibility and efficiency and policy support for net zero by 2050. Accelerated electrification of a wide range of applications leads to a rapid rise in electricity demand, which outstrips renewable supply and briefly prolongs the reliance on fossil fuel generation. This is largely replaced with renewables and grid-firming infrastructure at an orderly and increasing pace over the next decade. Gas distribution networks become increasing stranded as customers electrify through to the late 2030s.
Dual Fuel	Characterised by the fusion of extensive domestic electrification and the development of a material expert industry for hydrogen in the medium term. Domestic hydrogen is utilised for certain industrial applications and in select residential locations. Net zero is achieved by 2050 due to focused market and policy action and the orderly retirement of fossil fuel use. Gas networks are largely stranded by 2050, however, a subset service of 100% hydrogen customers.
Muddling Through	This reflects an uncontrolled, uncoordinated future characterised by stop-start progress towards net zero and limited changes to energy market dynamics. In this scenario, net zero by 2050 is at risk, driven by disorderly and uncoordinated government policy action. This leads to a combination of electrification with some gas distribution networks converted to low carbon fuels in the late 2030s as they attempt to remain viable.
Hydrogen Hero	Australia reaches net zero by 2050 through the orderly growth of a significant hydrogen industry for export and domestic use through widespread renewable generation. Hydrogen and electricity networks become linked in the 2030ss to provide stable, economically competitive, decarbonised energy. Gas distribution networks are fully utilised to deliver hydrogen to home, commercial and industrial applications.

[15] The model also has an ability to alter asset lives, which has a similar effect. However we use the tilt mechanism as this better allows us to price match to electricity through time.
[16] We do use scenarios however; 4 of them. These were developed for us by an independent expert panel (see Attachment 6.1).

uncertainty like that which we face.[17]

Our approach in the context of the AER's Information Paper

The AER's information paper expressed a preliminary view that adjusting regulatory depreciation is the most accessible regulatory tool to manage the demand uncertainty and influence the trajectory of future prices.[18] The AER notes that adjusting depreciation offers the greatest flexibility to respond to new information if future pathways turn out to be different.

The AER set out in the information paper what it expects to see from regulated businesses to support a proposal to accelerate depreciation. There are two parts to the AER's requirements. The first of these is the National Gas Rules, and in particular NGR 89(1) which covers how depreciation schedules should be developed. The requirements of the Rule are set out in section 6.2 of this Chapter.

We note in these criteria that there is nothing requiring straight line depreciation, which is simply current practice. More importantly, there is nothing preventing changes in asset lives; indeed we are required to use asset lives that can be changed when circumstances change.

There is also nothing which precludes consideration of asset stranding. Although the background reasons were different, we note that the AER in the current period made changes to the depreciation of cast iron mains reflecting a change in circumstances (the removal of those mains as part of our mains replacement).

The last four of the criteria are relatively easily met; by construction the PTRM will depreciate an asset over its life, whatever that might be and will do so only once. Meeting our cashflow requirements is something that is in our own self-interest and is more a check on the AER than on us, to prevent depreciation schedules that leave long periods where a firm cannot meet its cashflow requirements.

The key criteria are in NGR 89(1)(a) and (b); we need to depreciate (only once) each asset over its economic life in such a way as to produce efficient prices. Our approach in this respect is a continuation of what the AER does already, in a way that takes into account the change in circumstances in the industry.

The RAB is a fixed cost which needs to be allocated to customers across time. The efficient way to allocate such fixed costs, which distorts customer demand the least, is to do so on the basis of the elasticity of demand (See Attachment 6.4). If a firm is a monopoly and likely to continue to be so forever, then not only will elasticity of demand be low, but it will also most likely be uniform through time. Allocating the RAB based on elasticity results gives rise to the same allocation each year, or straight-line real depreciation.

However, if the prices of substitutes are falling, the elasticity of demand will rise (See Attachment 6.4). Now, allocating fixed costs through time means allocating fewer fixed costs to the future, when the elasticity of demand is higher, and more now, when it is lower. This is what our approach does; we are not changing the AER's existing approach, but merely taking into account a change which has occurred in the exogenous environment in which that approach is applied.

Our modelling approach captures the same increase in price sensitivity for future demand, and the depreciation response is designed to change depreciation (the allocation of fixed costs across customers) to minimise changes in demand.

As Incenta point out in their expert report:[19]

> *… the Victorian Networks' modelling of consumer choice is, in our view, the most robust method for accounting for the response of customers to changing relative prices in the future. The alternative would have been to assume elasticities of demand (with differing elasticities applying at the point in time where customers make a choice of appliances than applies between appliance decisions), but this alternative would have been much less reliable and informative than the Victorian Networks' approach of modelling the key drivers of long-term gas consumption*

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[17] See here. The methodologies used to plan in such a world are often much more sophisticated than ours, and we plan to explore this further in future. Eventually, we hope that the information set evolves such that the deep uncertainty is gone, and we can implement our model in a more conventional "optimisation" manner.
[18] See AER, 2022, *Regulating Gas Pipelines under Uncertainty*, p 44
[19] See Attachment 6.4 [74]

The second requirement is to meet the evidentiary requirements noted by the AER to identify:[20]

1. 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
2. those assets that may be repurposed for transporting hydrogen and those that cannot be
3. those assets whose economic lives may need to be adjusted to reflect the potential decline in long-term demand
4. the value of stranded assets under the different forecasting scenarios
5. the costs that may be avoided or incurred in the different forecasting scenarios
6. the level of customer support for the business's proposed action to manage the risk and the quality of that customer engagement
7. the price impact for the business's proposed action.

In Attachment 6.1 we map our response to each of these points in some detail.

The first, third, fourth and final of these are covered by the modelling. In fact, the model is intended to take information like that suggested in point 1, discover what it means for asset stranding (point 4), show how this can be addressed by adjusting economic lives (point 3) and maps this into long term price consequences (point 7). The different scenarios also involve different expenditure (point 5), which we explain in Attachment 6.1.

The second of the AER's points is discussed in Chapter 9. It is a separate issue to our consumer choice modelling, being an engineering issue which forms an input into the consumer choice model.

The penultimate point in respect of customer and stakeholder support is covered in detail in chapter 5.

Figure 6.1: Future of Gas Model Results

[20] See AER, 2022, *Regulating Gas Pipelines under Uncertainty*, p45

The results of our approach

The results of our modelling are shown in Figure 6.1. This figure shows the impact of increasing accelerated depreciation by $76 million over the forthcoming AA period. If we do nothing (orange lines), our network would strand in both the Electric Dreams and Dual Fuel scenarios.

Accelerating depreciation allows the network to continue to provide services at prices lower than the regulatory constraint imposed by the model for a significant period of time in almost all scenarios, as well as recover our invested capital.[21] This significant period of additional operation allows us ample time to prepare for our future, and at a relatively small cost today.

Bringing forward some depreciation in the next AA period also results in an increase in demand itself in all scenarios except Electric Dreams. Since we bring forward depreciation from a time when demand is more sensitive to a time when it is less sensitive, the increase in future demand from lower prices is significantly greater than the loss in current demand in each scenario. This increase ranges from 2 percent in Hydrogen Hero to more than 45 percent in Dual Fuel. This points to a significant gain in the efficiency of the use of the asset, just from changing the depreciation schedule. It will also assist to ensure price stability during the transition.

The model does not solve for "optimal" depreciation amounts, but rather serves as a way to test different proposals. Our proposal to accelerate $76 million of depreciation was developed to balance the need to start addressing the risks that arise from the future uncertainty with our commitment to and desirability of ensuring prices are either decreasing or are stable. The modelling shows that our proposal makes significant inroads into protecting the long term interests of consumers and our business while also delivering price stability. Sensitivity analysis around this central result is provided in Attachment 6.1. Significant increases in depreciation now do not give rise to substantially better long run demand or price performance and significant decreases in depreciation do not allow us to manage our risks effectively. We consider our proposal achieves a reasonable balance based on those results.

Incenta expressed the following view in its expert report which assessed our proposal:[22]

> *In our view, the outcomes of the Victorian Networks modelling provide a firm basis for accepting that their proposed advancements of depreciation would better meet the requirements of the gas regulatory regime than the current depreciation method (straight line depreciation with an inflation-indexed capital base).*

We note that we may need to adjust our proposal to accelerate depreciation to take into account further information we receive after lodging this Final Plan, including the Gas Substitution Roadmap and other key Federal, State and Local Government policy announcements.

6.6 Summary

Our future of gas approach has looked at the complex question of how our network might evolve over coming decades, where multiple future realities for the energy sector are feasible. We have found that our interests and those of our customers are inextricably interlinked; if we cannot remain competitive, prices for customers will rise, and ultimately, we will see some of our assets strand.

However, it is possible, if we act early enough, to address this issue; a relatively small change in depreciation allows us to offer smoother prices to consumers and, as a consequence, significantly reduce our own asset stranding risk.

[21] We impose a price constraint of 1.7 times current prices as the maximum for the model and this maximum (grey line) price would leave around 3% of our RAB unrecovered by 2060 in the Electric Dreams scenario, with full recovery in all other scenarios.
[22] See Attachment 6.4 [79]

7 Pipeline and reference services

Our proposed services for the next AA period are now mostly consistent with the services provided by the Victoria and Albury distribution networks.

IN THIS CHAPTER:

- **We propose to align most of our pipeline and reference services with those of AGN in the next AA period. As MGN and AGN are part of AGIG, we are aiming to maintain a consistent set of service offerings across the different markets we operate, wherever possible. This has no impact to customers as the actual delivery of gas remains unchanged.**
- **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 around 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 MGN.

Based on the stakeholder feedback received to date, we propose to align most of our pipeline and references services with AGN 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 Final Plan.

7.1 Regulatory framework

This Final 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.[23] This RSP was developed on the basis of feedback provided by our customers and stakeholders and the reference service factors set out in the NGR.

[23]See: https://www.aer.gov.au/system/files/Multinet%20-%20Reference%20Service%20Proposal%20-%201%20July%202021.pdf

The AER consulted on the RSP with stakeholders and in November 2021 approved our proposal.[24]

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.

7.2 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;
- there were any additional services that should be reference services; and
- there was support for alignment of services across the three Victorian network businesses.

Our reference groups supported aligning MGN services with AGN where it was appropriate to do so.

One member of our RRG suggested one service should remain classified as an ARS (Disconnect in Street service), but acknowledged the low utilisation during the current AA period. In taking on this feedback, we propose to classify the service as a non-reference service in the next AA period, rather than removing the service from our suite of services, as originally proposed.

No additional services were considered necessary by reference group members.

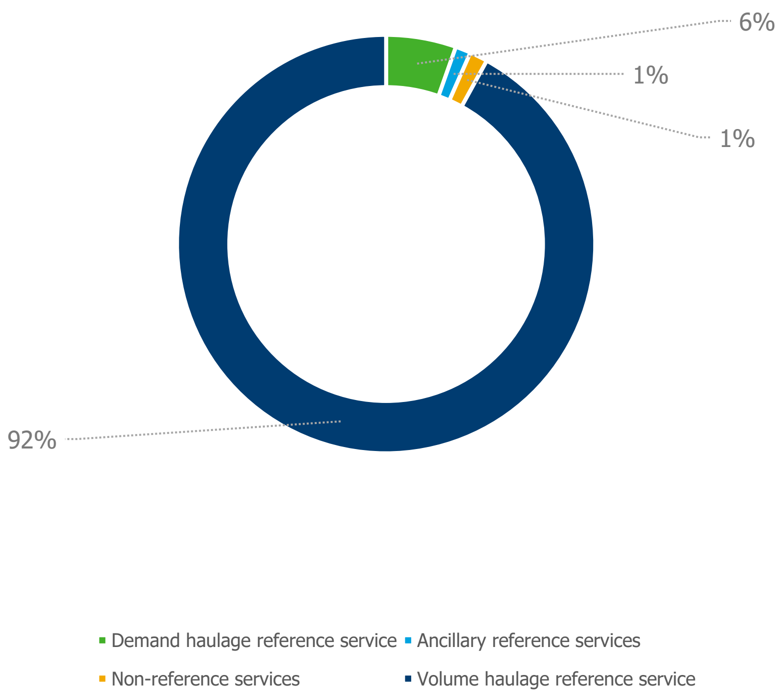
After submitting our RSP, the AER provided stakeholders an opportunity to comment before making its final decision. The AER received one submission, which focussed on promoting price transparency on our non-reference services. Providing cost transparency to our customers is embedded in our existing processes,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

non-reference services have been determined.

7.3 Pipeline services

Table 7.2 sets out the reference and non-reference services we propose to offer in the next AA

Figure 7.7.1: MGN revenue share 2016 to 2020



[24] See: https://www.aer.gov.au/system/files/AGN%20Vic%20Albury%202023%E2%80%9328%20-%20Reference%20service%20proposal%20-%20AER%20final%20decision.pdf

period and consistent with the AER's RSP decision.

The classification of the services in this table as either reference or non-reference services largely aligns with those of AGN. It is 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 around 99% of the revenue earned by MGN in the current AA period, while non-reference services have accounted for 1%. What this means is that the AER determines the price we charge for services that make up more than 99% of our revenue.

7.3.1 Reference services

In the next AA period, we propose to offer two haulage services and five ancillary services as reference services (refer Table 6.2).

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

- volume haulage service, delivering gas to around 720,000 residential and around 14,000 commercial customers; and
- demand haulage service, delivering gas to over 270 industrial customers.

These proposed reference services align with AGN. We also propose one ARS (Disconnect in Street) to be classified as non-reference service in the next AA period, given the low uptake by the market in the current 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.

7.3.2 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:

- 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.

In addition to making changes to align our non-reference services with AGN, we are proposing to treat two existing non-reference services (Downgrade Meter Size and Pressure Change) that are currently classified as Other non-reference services as separately identified non-reference services in the next AA period.

Table 7.1: Customer insights on pipeline and reference services

What we heard	Our response
• Stakeholders supported the proposed reference and non-reference services.	• We propose to align most of our pipeline and reference services with those of AGN in the next AA period, which is consistent with our Reference Service Proposal approved by the AER in November 2021.
Final Plan Outcome	
Stakeholders support our proposal to align most of our pipeline and reference services with those of AGN in the next AA period, which is consistent with our Reference Service Proposal approved by the AER in November 2021.	
Stakeholders (retailers) were supportive of our proposed pipeline and reference services.	

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.

7.4 Summary

We propose to align reference and non-reference services with AGN 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 7.2: Proposed services for the Multinet distribution network 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.
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.
Special Meter Reading	Meter reading for a DP that is in addition to the scheduled meter reading that forms part of the Haulage Reference Service.
Non-reference services	
Tariff D connections	Means the Connection and maintenance of the Connection at a Tariff D Distribution Supply Point.
Tariff L connections	Means the Connection and maintenance of the Connection of a Tariff L Distribution Supply Point.
Tariff V Complex connection	Means the Connection and maintenance of the Connection at a Tariff V Distribution Supply Point that is not a Basic Connection Service.
After Hours connection and re-connection for	Means the reconnection of supply to a premise outside of standard connection hours.

Service	Description
tariff V customers between the hours of 4.00pm and 8.00pm	
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.
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).
Alter Meter Position	To be used when a customer is requesting the relocation of an existing gas meter to a new position.
Installing of a second service valve pit and disconnect gas supply	The service would involve disconnection by excavation in the street (paved/unpaved and with/without traffic management) at the skinner valve to allow the insertion of a new service valve in the service line to the property, install a new service valve (a second service valve in a public location) that is able to disconnect and reconnect gas supply without access to the premises/metering installation.
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.
Other non-reference services	Any other non-reference service requested by the customer or retailer and which the Service Provider agrees to provide.

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 20% compared to our benchmarks, while also servicing a forecast 25,000 net additional customers. Lower costs and higher connections will benefit customers through lower prices in the next period.**
- **We are proposing two new opex initiatives in the next AA period which have been shaped by our customers and input from stakeholders; the Priority Services 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 categories 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 $406 million over the next AA period (see Figure 8.1 and Table 8.1). Excluding the effect of our proposed change in capitalisation policy, this is around 15% ($40 million) higher than what we expect to incur in the current AA period (forecast to December 2022).

This increase in opex can be attributed to the recent short term high inflation (around $5 million), real cost increases of some costs that we have incurred over the current AA period from 2018 to 2021 (in particular, higher safety levies and onshoring of our call centre), along with new activities in the next AA period including uplift of our cyber security, renewable gas communications and our Priority Service Program.

For most other categories we have been able to keep costs at similar levels to those we will incur in the current AA period, despite servicing an additional 25,000 net customers in the current AA period and a further 6,000 net customers in 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)		371.8	✓ Overall real cost saving of ~20% compared to benchmarks and reflecting real cost increases incurred between 2018 and 2021
Plus ongoing costs not fully reflected in base year		6.8	✓ We have adjusted our base year for a full year of onshore call centre costs
Plus change in capitalisation of some overheads		3.0	✓ 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		1.9	✓ Includes real labour cost escalation, output growth and 0.4% pa productivity growth
Plus Capex to opex step activities		11.6	✓ Activities previously treated as capex which do not extend asset lives
Plus renewable gas communication step change		3.0	✓ We are investing in a renewable gas communications package as, while 90% of customers consider decarbonisation as important, very few know about the decarbonisation plans for our gas networks
Plus cyber security uplift step change		3.6	✓ Uplift cyber risk management capabilities in line with new obligations and good industry practice
Plus Priority Services Program		4.5	✓ Introduction of Priority Services Program
Total opex excluding ARS & DRC	**352.3**	**406.3**	

Figure 8.1: Opex excluding debt raising costs

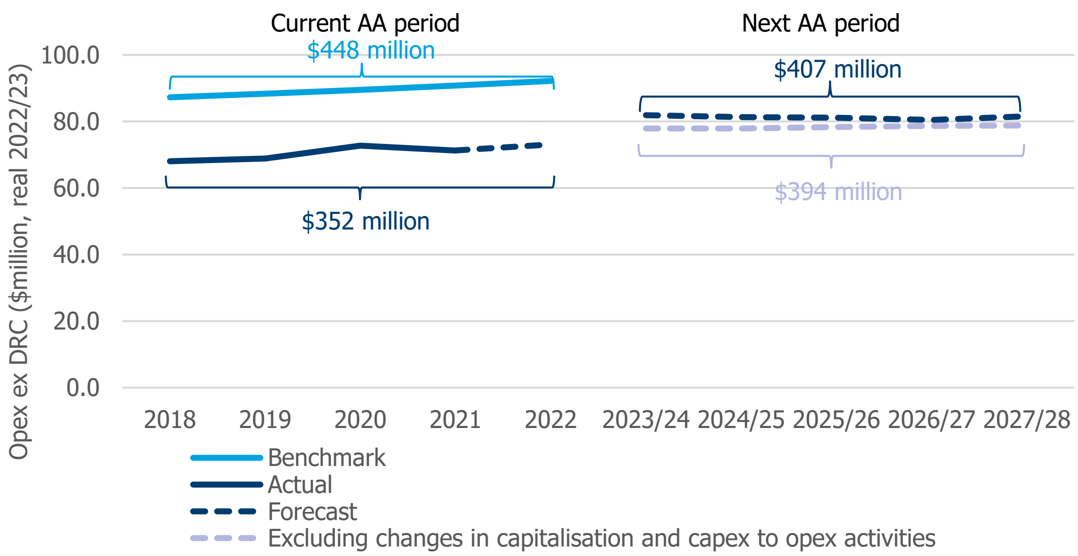


Figure 8.2 below shows a comparison of benchmark and actual opex per customer in the current AA period compared to forecast opex per customer in the next AA period. It shows that we have achieved a significant reduction in opex per customer in the current AA period and that opex per customer is forecast to increase by about 5% in the next AA period before changes in capitalisation and new activities, but even with these changes still remains considerably below benchmark levels for the current AA period.

The incentives provided by the operation of the Efficiency Carryover Mechanism (ECM), coupled with our internal and external controls, will continue to ensure that the opex we incur is both prudent and efficient. This will also ensure that any cost savings are passed through to customers, in the same manner as the efficiencies achieved in the current AA period will be.

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

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

A summary of customer and stakeholder insights that relate to our opex is provided in Table 8.2.

8.2.1 Customers

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, while also keeping prices stable.

Figure 8.2: Comparison of opex per customer

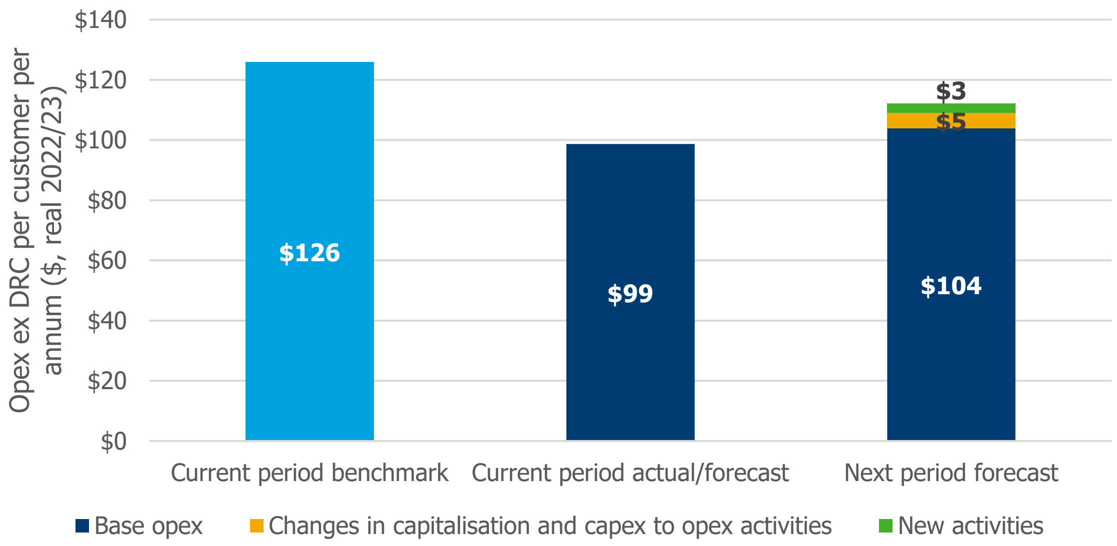


Table 8.2: Customer and stakeholder insights for our opex plans

What we heard	Our response
• Customers expect us to maintain current levels of reliability, safety and customers services. • Stakeholders would like us to minimise expenditure while the future is uncertain. • Stakeholders would like to better understand the drivers of our change in capitalisation proposal before they can support it. • Customers strongly supported the idea of new services designed to support customers experiencing vulnerability, noting the impacts of Covid-19 in their communities. • Most stakeholders support our proposal to introduce a Priority Service Program in Victoria. A few expressed the need to ensure effective safeguards are established when developing the Priority Service Register. • Stakeholders are keen to see more detail on the PSP including the specific activities being proposed and where spend is being allocated. Some questioning whether • Social Service Organisations had a strong preference for the Priority Service Program to be Victoria wide, as opposed to network specific. • Customers support MGN's proposal for a renewable gas communications and education package that includes community activities and student learning and education. • We received mixed levels of support from stakeholders for investment in renewable gas communication and education. Stakeholders felt strongly that communication and marketing activities should not be funded as part of a step change. • Stakeholders questioned whether the 0.4%p.a. productivity is sufficiently ambitious, and whether AGN South Australia is a good comparison.	Our opex proposal has been developed to maintain current levels of safety, reliability and customer service. We recognise there is policy uncertainty and have used the most up to date information available to inform our proposals. We note we must continue to maintain and invest in our network to ensure we meet our safety and reliability obligations and deliver on the expectations of our customers. Sections 8.4.1 and 8.4.2 explain the drivers for our proposed changes in capitalisation of overheads and capex to opex activities. An independent review of the changes is also provided as Attachment 8.3 to this Final Plan. We have included the Priority Service Program in our Final Plan. The proposed program which has been developed through engagement with the Priority Service Panel is outlined in Section 8.6, with more detail available in our PSP Business Case (Attachment 8.2). We have reduced the opex step change we are seeking in relation to our proposed renewable gas communication and education program by over half from our Draft Plan. The proposed communication and marketing activities will be funded by the business (no step change) and the uplift in community education activities and school program will be funded by customers through a step change (see Section 8.5 and Attachment 8.2). We have listened and engaged ACIL Allen to undertake some further opex productivity analysis for Multinet which is provided in Attachment 8.6. We will use this work to engage further with stakeholders post-lodgement. We will continue to engage on our opex plans during our post-lodgement engagement program.

Final Plan Outcome
Our opex proposal will ensure we can maintain strong safety and reliability performance and continue to meet customer service expectations. This Final Plan provides detailed supporting information to support our proposed opex programs (see Attachments 8.1 – 8.6).
Customers were highly supportive of our opex plans, particularly Renewable Gas Education and the PSP.
Stakeholders wanted to see us minimise opex expenditure while the future is uncertain.

Tailored and accessible services designed to better support priority customers and those experiencing vulnerability is critically important to customers. 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 Service Program for customers experiencing vulnerability. More information on our Priority Service Program can be found in section 8.5.

Customers seek communication that raises awareness about renewable gas and equips them for decision-making around their future energy mix. They expressed a desire for MGN to play a role in educating customers and communities at large about cleaner energy and 93% of customers supported our draft proposal for renewable gas communications and education. Our renewable gas communications and education program is discussed in section 8.6.

8.2.2 Stakeholders

Stakeholders are supportive of maintaining safety, reliability and customer service. However, throughout our consultation process, stakeholders emphasised they would like us to minimise expenditure while the future is uncertain.

Stakeholders were supportive of how we have developed our proposal with most of the discussion focussed on base year adjustments and new proposals, including changes in capitalisation, the Priority Service Program and renewable gas communications and education.

In particular, stakeholders wanted to understand what was driving the base year adjustments and proposed changes in capitalisation. This Final Plan includes more information on the drivers for our base year adjustments (section 8.4.1), proposed changes in capitalisation (section 8.4.1) and capex to opex activities (section 8.4.2). We also had these proposed changes independently reviewed by BDO. BDO's report is provided as Attachment 8.3 to this Final Plan.

The majority of stakeholders were supportive of our proposed Priority Service Program, acknowledging the role networks play in the face-to-face relationship with customers. Collaboration with other organisations including retailers and social service was a strong theme in our discussions. More information on our proposed Priority Service Program can be found in section 8.5.

There was mixed support amongst stakeholders for our renewable gas communications and education program (in contrast to strong support from customers). We consider this is a very important program as our business and customers navigate the energy transition. However, we have halved the step change (from the Draft Plan) associated with the program to cover the community engagement activities and schools' program which they strongly valued. We will absorb the other costs associated with the proposed program. More information on our revised renewable gas communications and education step change can be found at section 8.6.

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. Actual costs incurred in 2021 have been used as the base year.

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)

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 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, 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 -$2.6 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.

In particular, the opex we have forecast in 2021 does not reflect a full year of our onshore call centre. In October 2021 our offshore call centre activities were transferred onshore where they will continue for the next AA period. The move to onshore our call centre was required as part of our agreement with the Foreign Investment Review Board to meet our data storage obligations when MGN was acquired by new owners in 2017. This adds $1 million to our base year opex. This is calculated based on the full year ongoing cost of these activities in 2022 of $2 million, minus the $1 million we actually incurred for these activities in 2021. More information about this base year adjustment can be found in our call centre onshoring business case in Attachment 8.2.

The base year adjustment in this Final Plan is $1 million less than the adjustment we proposed in our Draft Plan. The reduction relates to the removal of an adjustment for network development activities which following stakeholder feedback, we will fund as part of BAU activities.

Removal of opex categories to be forecast separately

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

As noted above, we have developed separate forecasts for ancillary reference service costs and debt raising costs. We have therefore excluded $2 million from the 2021 actual expenditure to remove the costs associated with ancillary reference services, and $1 million for debt raising costs. This is consistent with our Draft Plan.

Accounting for changes to capitalisation of overheads

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

Our capitalised overheads account for around $6 million of expenditure per year. These overheads relate to activities undertaken by our non-operational staff, such as:

- network analysis, design, mapping and costing support in relation to network extensions and modifications; and
- 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 Finance and IT.

We have reviewed the activities included within our overhead costs which we have historically capitalised. We have identified a portion of these activities which are more akin to operating expenditure than capital expenditure, and we are proposing they be treated as operating expenditure going forward. These activities are indirect costs to support the provision of the above activities such as Finance and IT.

We engaged BDO to independently review this approach against accounting standards and regulatory precedent in Australia. BDO agreed treating these costs as opex is reasonable and consistent with accounting standards and regulatory precedent, and how other businesses treat similar costs. BDO's report is provided as Attachment 8.3 to this Final Plan.

To account for this capitalisation policy change in the opex forecast, $0.6 million (or 10%) of the forecast capitalised overheads for 2021 have been included in the base year opex. This results in a $3 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 6% on average in the current AA period. This is consistent with the values proposed in our Draft Plan and similar to the overhead rate that applies in AGN.

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 have the ancillary 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 Final Plan is $65 million. The costs can be assumed to be both prudent and efficient given the operation of both:

- the ECM (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 Governance), 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:

"Multinet is subject to the incentives of an ex ante regulatory framework, including the application of an efficiency carryover mechanism for opex. 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."[25]

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

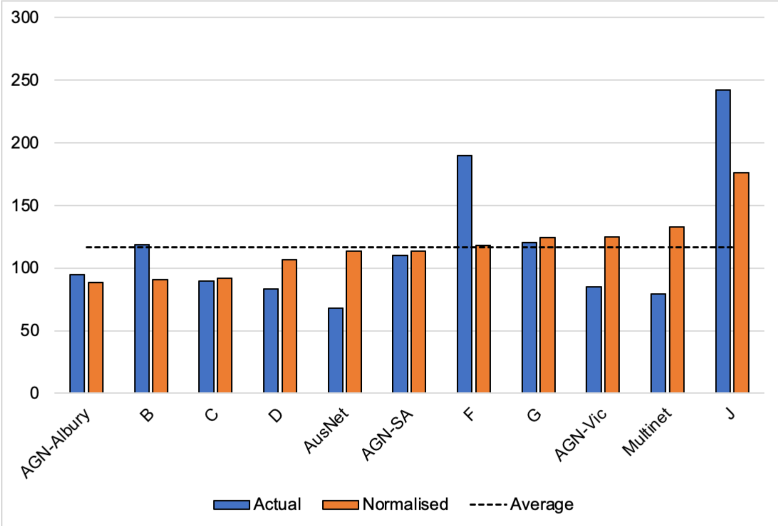
Table 8.3: Establishing the base year for forecasting opex in the next AA period ($ million, 2022/23l)

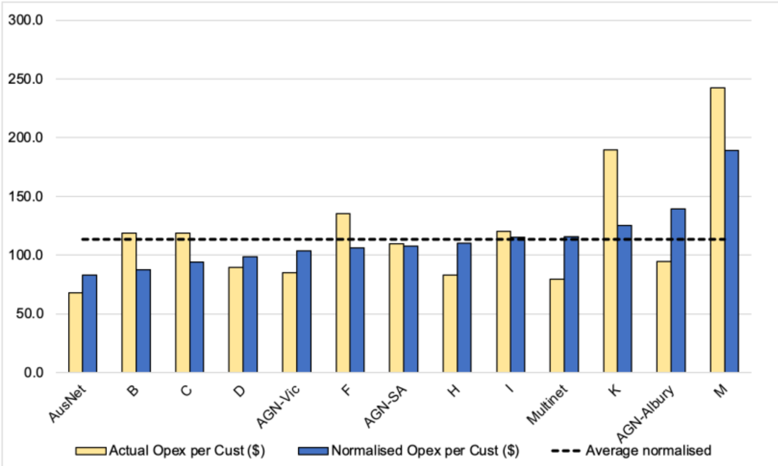
Category	2021 forecast
Total opex	70.2
Minus UAFG and provisions	-2.5
Minus category specific forecasts (debt raising costs and ancillary reference services)	3.4
Base year opex	**69.3**
Plus change in capitalisation of overheads	0.6
Plus full year adjustments	1.4
Base year for forecasting	**71.3**

[25] AER, "Attachment 7: Operating Expenditure | Draft Decision Multinet Gas Networks 2018-22", July 2017, p 7.

Another tool used to consider efficiency of the base year is industry wide benchmarking. The most recent industry benchmarking study for gas distributors was undertaken by Economic Insights in June 2020. Economic Insights analysis shows that MGN's actual opex per customer between 2015 and 2019 was below the average, with normalised opex per customer (which takes account of several variables such as customer numbers, mains length, capital stock and time) at or around the average. We also note MGN achieved opex efficiency gains over the period 2015 to 2019, and that 2021 opex (which forms the base year) is consistent with 2019 levels.

Figure 8.4: Normalised opex per customer (2015-2019)





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.

A summary of positive step changes and how we are proposing to treat them in the next AA period is:

- higher IT opex driven by continuing requirements to improve our cyber security – opex step change;
- additional opex for the delivery of more digital customer services – absorb;
- a new renewable gas communications and education program – opex step change; and
- one-off opex activities associated with our hydrogen readiness network adaptation plans – absorb.

Table 8.4: Opex step changes in the next AA period ($million, 2022/23)

Category	Total AA
Cyber uplift	3.6
Renewable gas education	3.0
Total step changes	**6.6**

As a critical infrastructure business, we are uplifting our cyber security capabilities in line with new legislative obligations and the risks our business faces from cyber threats. This requires additional workforce and security services compared to current levels to continue the uplift program and then maintain ongoing good practice cyber risk management. More information on our cyber program can be found in our AGIG One IT business case at Attachment 9.19.

Our renewable gas communications and education program has been developed in response to customer feedback.

In our Draft Plan we proposed $7 million for broad communications, more community engagement activities and a school education program. While 93% of customers who participated in our workshops supported our proposed program, there was mixed support from stakeholders, with some feeling strongly that communication and marketing activities should not be funded as part of a step change.

We have therefore revised the step change for renewable gas communications and education in this Final Plan to $3 million. This reflects that the business will fund the broad marketing and communications activities proposed, with customers (through this proposed step change) funding the uplift in community engagement activities and new school education program. This is consistent with the areas strongly valued by our customers and will ensure that customers are aware about renewable gas and equipped with information to support them in their decision-making around their future energy mix. More information on our renewable gas communications and education program can be found at section 8.6 and in our renewable gas communications and education business case at Attachment 8.2.

Capex to Opex Activities

In addition to the step changes outlined, we have also identified programs previously classified as capital expenditure that would better fit the definition of opex.

We engaged BDO to independently review this approach against accounting standards and regulatory precedent in Australia. BDO agreed treating these costs as opex is reasonable and consistent with accounting standards and regulatory precedent, and how other businesses treat similar costs. BDO's report is provided as Attachment 8.3 to this Final Plan.

The forecast scope and costs of these capex to opex activities have been developed using a bottom-up approach.

The activities include;

- a HDPE sampling and assessment program which will collect material samples from across the HDPE network and have them assessed to determine the remaining life of these mains, and inform ongoing asset management required in future AA periods;
- reactive mains replacement where we reactively repair and replace small sections of mains which have failed in service;
- inline inspection of transmission pipelines using a tool called a pig; and
- replacement of marker posts along transmission pipelines.

Table 8.5: Capex to Opex transfers in the next AA period ($million, 2022/23)

Category	Total AA
HDPE Assessment	1.2
Reactive Mains Replacement	4.3
Pipeline Inline Inspection	6.0
Marker Post Replacement	0.2
Total Capex to Opex	**11.7**

8.4.3 Trend

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

We engaged independent experts to develop forecasts for components of the trend, resulting in a trend rate of change of 0.2% 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: [26]

- 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 0.7% 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 8.6).

We engaged BIS Oxford to provide input price escalation forecasts to 2027/28. BIS Oxford's report is provided as Attachment 8.4 to this Final Plan. The AER engages Deloitte Access Economics to provide input price escalation forecasts. We have used the Deloitte Access Economics forecasts the AER used in its most recent decision for AusNet's Victorian Electricity Transmission business.

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).

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
- 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 those used for our network in the current AA period, with customer numbers given a 55% weighting and kilometres a 45% weighting.

The application of these assumptions results in an average annual output growth rate of 0.4% per year over the next AA period (see Table 8.8).

This is consistent with the approach we took for the current AA period and with that recently approved by the AER, Jemena's New South Wales gas distribution network and AGN's South Australian gas distribution network.

Table 8.6: Calculation of annual real labour cost escalation

Labour cost estimates (EGWWS sector)	2023/24	2024/25	2025/26	2026/27	2027/28
BIS Oxford (A)	1.03%	1.42%	1.49%	0.87%	0.68%
Deloitte Access Economics (B)	0.18%	0.32%	0.50%	0.28%	0.28%
Annual labour cost escalation (average of A and B)	**0.60%**	**0.87%**	**1.04%**	**0.57%**	**0.48%**

Table 8.7: 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	59.7%	0.60%	0.87%	1.04%	0.57%	0.48%
Materials	40.3%	0.00%	0.00%	0.00%	0.00%	0.00%
Annual input cost escalation		**0.36%**	**0.52%**	**0.62%**	**0.34%**	**0.29%**
Cumulative input cost escalation		**0.36%**	**0.88%**	**1.50%**	**1.84%**	**2.13%**

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

We consider this approach continues to reflect 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).

In this Final Plan, we have applied annual productivity growth of 0.4% per annum. This is consistent with the value applied in our Draft Plan.

In our Draft Plan we explained the 0.4% productivity per annum was based on the value accepted for AGN's South Australian network, work we engaged ACIL Allen to undertake on productivity trends for that review and evidence in ABS statistics of a slowdown in productivity over the past year, since our South Australian Network decision.

Stakeholders queried whether this value was ambitious enough and whether the value applied for AGN South Australia was appropriate for application to the Victorian networks. In response, we have engaged ACIL Allen to update its analysis for all three of the Victorian distribution businesses, plus AGN Albury. ACIL found an average forecast opex productivity growth factor of 0.2% pa, therefore we consider our application of 0.4% pa is ambitious. ACIL's report is provided at Attachment 8.6 to this Final Plan.

The application in this Final Plan of a productivity growth factor of 0.4% per year over the next AA period results in a $4 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. Consistent with our Draft Plan, we are also proposing a new category specific forecast for our Priority Service Program.

The Priority Service Program is similar to the vulnerable customer assistance program approved 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 the category specific 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.

Table 8.8: Calculation of the output growth factor

Category	Weight	2023/24	2024/25	2025/26	2026/27	2027/28
Customer numbers	50.6%	0.17%	0.11%	0.16%	0.36%	0.54%
Network length (km)	40.4%	0.53%	0.48%	0.52%	0.66%	0.79%
Weighted output growth factor		**0.35%**	**0.29%**	**0.34%**	**0.50%**	**0.66%**

Table 8.9: Calculation of output growth net of productivity growth

Category	2023/24	2024/25	2025/26	2026/27	2027/28
Weighted output growth factor	0.35%	0.29%	0.34%	0.50%	0.66%
Annual productivity	0.40%	0.40%	0.40%	0.40%	0.40%
Annual output growth net of productivity	**-0.05%**	**-0.11%**	**-0.06%**	**0. 10%**	**0.26%**

We forecast to spend a total of $13 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 million in the next AA period.

Priority Service Program

Our Priority Service 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. For more information on our Priority Service Program see section 8.5 and our Priority Service Program business case at Attachment 8.2 to this Final Plan.

8.4.5 Summary

Figure 8.5 and Table 8.10 set out our forecast opex for the next AA period.

We expect to incur $411 million in opex over the next AA period. This is $14 million above that in our Draft Plan and 16% higher than what we expect to incur in the current AA period (forecast to 31 December 2022).

The key drivers of the increase since our Draft Plan are higher actual opex in the base year compared to forecast, higher forecasts for capex to opex activities and higher inflation forecasts for 2022 and 2023.

Excluding the effect of the proposed changes in capitalisation, capex to opex and new activities, our opex in the next AA period is around 15% ($41 million) higher than what we expect to incur in the current AA period.

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), maintain our network assets as required by our asset management plans (AMPs), communicate our decarbonisation plans and better support customers facing vulnerable circumstances, along with other operational activities to maintain 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

Figure 8.5: Opex in the next AA period by category ($million, $2022/23)

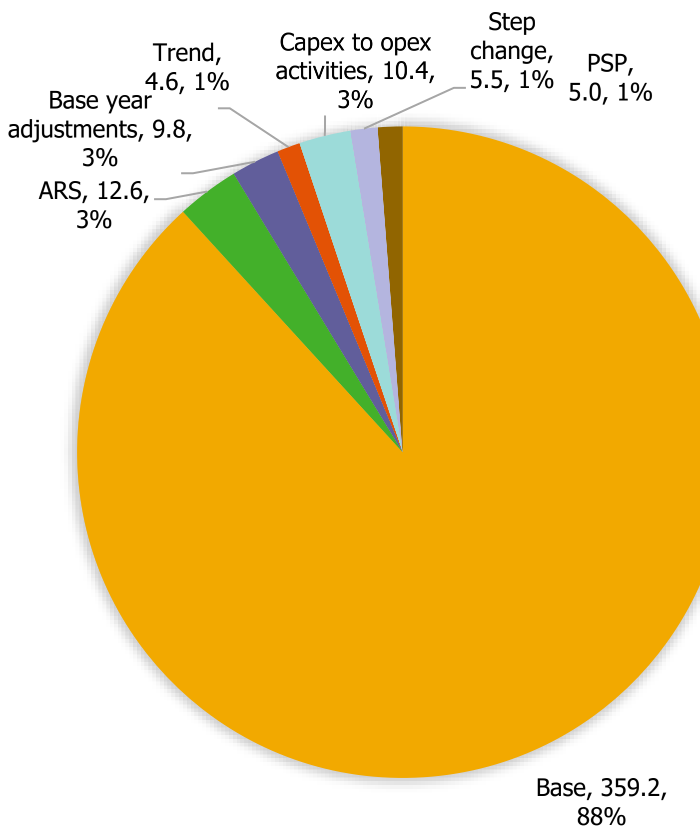


Table 8.10: Opex forecast summary ($ million, 2022/23)

	2023/24	2024/25	2025/26	2026/27	2027/28	Total
Base year opex forecast	71.8	71.8	71.8	71.8	71.8	359.2
Full year adjustments	1.4	1.4	1.4	1.4	1.4	6.8
Change in capitalisation of overheads	0.6	0.6	0.6	0.6	0.6	3.0
Base year	**73.8**	**73.8**	**73.8**	**73.8**	**73.8**	**369.0**
Step changes (renewable comms)	0.6	0.6	0.6	0.6	0.6	3.0
Step changes (cyber uplift)	0.5	0.5	0.5	0.5	0.5	2.5
Capex to opex activities	3.2	2.6	1.9	0.9	1.9	10.4
Trend	0.3	0.6	1.1	1.2	1.4	4.6
Ancillary reference services (ARS)	2.5	2.5	2.5	2.5	2.5	12.6
Priority services program	1.2	0.9	1.0	0.9	1.0	5.0
Total opex forecast (ex debt raising costs)	**82.1**	**81.6**	**81.3**	**80.5**	**81.7**	**407.1**
Debt raising costs	0.7	0.7	0.7	0.8	0.8	3.7
Total opex	**82.8**	**82.3**	**82.0**	**81.3**	**82.5**	**410.8**

- being sustainably cost efficient – we will pass through opex savings made in the current period to our customers, absorb a number of upward cost pressures and uplift our cyber risk management capabilities at the lowest sustainable cost.

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 and stakeholders:

- our Priority Service Program to provide additional support to customers facing circumstances of vulnerability; and
- our new renewable gas education 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.

8.5 Priority Service Program

This section sets out our plans to improve services for vulnerable customers over the next AA period. Since our Draft Plan, we have made refinements to our proposed Priority Service Program, working together with AGN and AusNet, the other two gas distributors in Victoria.

As discussed in Chapter 2, we are one of the founding businesses across the energy supply chain that 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, 92% of customers said that providing dedicated services to vulnerable customers was important or very important. Figure 8.6 summarises the key findings on priority services for customers facing circumstances of vulnerability across our series of customer workshops.

Gas networks have a role to play in recognising the circumstances of customers and providing support. As highlighted in the Consumer Policy Research Centre's report to the AER, "essential service providers can exacerbate harm if they do not respond in an informed, sensitive way to the personal circumstances of their customers."[27]

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

To help us design a fit-for-purpose priority service program we set up an Advisory Panel of experts from community organisations and worked with them over a series of workshops to develop our proposed priority service program. More information on our Priority Service Panel can be found at Attachment 8.2 to this Final Plan.

The feedback received from the Panel, along with the feedback and insights gathered through our customer workshops has helped us to shape our proposed Priority Services Program. Importantly, the program has been designed in a way that:

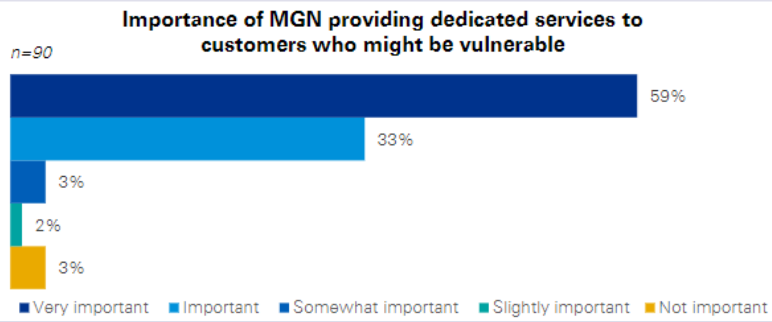
- does not duplicate existing programs;
- provides a material uplift in customer service; and
- considers implementation implications.

Our proposed Priority Service Program is a new program for the

Figure 8.6: Customer insights on priority services for customers facing circumstances of vulnerability

Tailored and accessible services designed to better support priority customers and those experiencing vulnerability is critically important to customers

- Customers recognise that circumstances vary, and support the need to provide dedicated and tailored support where required.
- There is a high level of customer support for MGN providing dedicated services to priority customers, and ensuring CALD customers have tailored support and channels to receive information.
- Customers emphasise the importance of a fair and holistic definition of vulnerability.
- Customers support MGN's proposal to create a dedicated support role/team, train frontline staff, provide rebates (i.e. for free gas safety checks) and develop a Priority Services Register.



27 CPRC, Exploring regulatory approaches to consumer vulnerability – A report for the AER, February 2020

next AA period, with the following objectives:

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

To meet these objectives, we propose the following 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 MGN, 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 MGN 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.

The program is summarised in Figure 8.7 below.

We will continue to work with the other Victorian gas networks, energy retailers, stakeholder groups, government and social services organisations in the next AA period to operationalise the program.

Figure 8.7: Our Priority Services Program

Priority Service Program initiatives	Customer benefits
Dedicated customer support team	Specialist team trained to support PSP customers
Check-ins and additional support during outages	Additional care and consideration during extended gas outages e.g. heating, cooking
CALD communications	Tailored, digital and easy English comms
Gas appliance safety checks	Direct financial benefits to customers and peace of mind at home
Emergency appliance repairs	

8.6 Renewable gas communications and education

Customers want MGN to play a role in educating customers and communities at large about cleaner energy. Customers expressed a strong and interest in learning about the future of gas and opportunities for cleaner energy practices. Some customers cited a desire for information and transparency on efforts taken by MGN in the transition to more sustainable practices. Specifically, customers expressed interest in MGN:

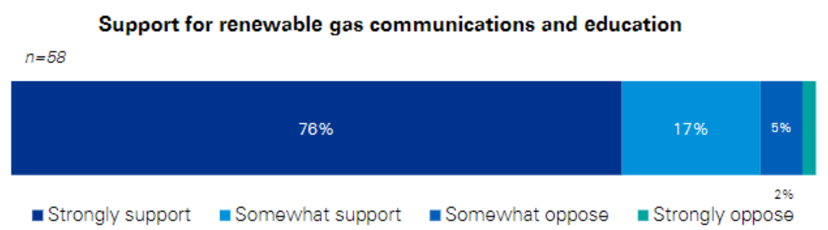
- Educating the community around the future of gas and the transition to renewables, in order to increase awareness and understanding;
- Being transparent on its progress in the transition to cleaner energy;
- Being transparent on price implications as it transitions to renewables;
- Informing customers of the process and impact (such as on appliances), as a result of the shift to renewables.

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. A prudent service provider acting efficiently would seek to ensure its customers are informed and educated about such a large transition. 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.

Figure 8.8: Customer insights on renewable gas communications

Customers seek communication that raises awareness about renewable gas and equips them for decision-making around their future energy mix.

- Customers have low levels of awareness of renewable gas and are keen to learn more
- There is customer support for investment in a renewable gas communications campaign, with customers citing student education and community events as key.
- Targeting and educating children was viewed as critical, particularly for the CALD community.
- Customers support MGN's proposal for a renewable gas communications and education package that includes community activities and student learning and education.
- "Customers want as much transparency as possible
- "The more positive messages… and the more information available to educate people on what is being planned, the better



In our Draft Plan, we proposed a Renewable Gas Communications Program which included broad communications, more community engagement activities, and a new school education program. This reflected 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 consider that the proposed enhanced program is needed as it:

- 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 and efficient 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 Chapter 6 Future of Gas).

Since our Draft Plan we have revised the program to be funded by customers in response to stakeholder feedback. In this Final Plan we are proposing to undertake all of the same activities we proposed in our Draft Plan, however, broad customer communications activities will be funded by the business and will no longer form part of an opex step change. The $3 million proposed opex step change for renewable gas communications in this Final Plan will deliver an uplift in community engagement activities and a new school education program. These initiatives were most strongly valued by our customers through our customer workshops.

We will leverage our recent experience implementing enhanced communications on our low carbon future to our South Australian customers which has delivered very positive results to deliver broad customer communications on the renewable future for gas.

Our proposed Renewable Gas Communications and Education program is summarised in Figure 8.7.

8.7 Summary

Our $407 million opex forecast for the next AA period is slightly higher than the opex we expect to incur in the current AA period, on a like for like basis. We are also introducing two new initiatives and shifting some costs that have previously been treated as capex. Overall, our customers will benefit from the opex savings we have achieved over the current AA period, as well as the new focus on supporting those facing

Figure 8.9: Summary of our Renewable Gas Communications Program

Funded by the business	**Customer Communications (35% reach)** • Renewable Gas advertisements on free-to-air television channels, introducing renewable gas and encouraging consumers to visit the website to learn more (2 month campaign, twice yearly) • Digital advertising on a range of news and high traffic websites • Social media engagement on renewable gas
Funded by customers **($3 million over five years, or <$1 per customer p.a)**	**Community Activities** • Presentations and forums with community groups, including CALD • Site tours at renewable gas facilities • Attendance at community events • Supporting online renewable gas materials **Student Learning and Education** • In person and online resources to educate students, tailored to CALD students • Hands-on and interactive curriculum • Professional learning opportunities for teachers • Attendance at student events, including science fairs

vulnerable circumstances and the future of 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.

Governance

Review and approval

Our review objectives (see Purpose), particularly our objective to develop a plan that is capable of being accepted by customers and stakeholders underpins our approach by ensuring we adopt AER approved methodologies and take on board customer and stakeholder feedback.

The development and approval of our Final Plan is overseen by the Review Steering Committee (RSC) which comprises all members of the Executive Management Team and is led by the CEO.

The RSC is supported by a working group comprising representatives from across AGIG.

Alongside the Final Plan, we are required to submit information in response to a Regulatory Information Notice from the AER. This information is accompanied by a statutory declaration completed by the Chairman and requires certain information to be audited/reviewed by an independent auditor.

Forecasts

Our Final Plan uses a number of forecasts including for opex, capex, and demand.

Forecast expenditure in our Final Plan 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. All forecasts must be arrived at on a reasonable basis and represent the best forecast or estimate possible in the circumstances.

More detail on specific forecasts and how they are developed is available in relevant sections of the Final Plan:

- Opex: Section 8.4
- Capex: Section 9.4
- Demand: Chapter 13.

Outsourcing arrangement

Our assets are operated by Comdain under an Operations and Managed Services Agreement (OMSA).

The services provided under the OMSA include:

- fault response and repair;
- planned maintenance;
- mains and time expired meter replacement;
- augmentation and other authority projects;
- installation of new services and meter connections, including industrial and commercial meter set fabrication.

Delivering efficient capital expenditure

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 the figure over.

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. Many of these are approved by Energy Safe Victoria (ESV) and the Essential Services Commission of Victoria (ESCV).

Our Safety Case is 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.

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 Strategy 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 Metering Strategy which details our compliance obligations and how this drives the forecast volume of meters to be replaced over the next AA period;
- Network strategies outlining how the networks are designed and safely operated; and
- Asset Strategies 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.

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. This provides strong financial controls and governance in the delivery of capex.

Procurement Policy

All procurement activities are subject to our Procurement Policy and Purchasing Procedure (see Attachment 9.4). This ensures we carry out these activities in an consistent, effective, confidential and ethical manner. The policy also ensures we:

- Maximise cost savings;
- Mitigate risks associated with the provision of goods and services; and
- Achieve excellence in both operational and financial performance.

Internal Audit

Our internal audit function provides independent assurance that our risk management, governance and internal control processes are operated effectively.

Each year the Board approves an Internal Audit Plan. Independent external professional firms are engaged to deliver audit reviews. Our shareholders also undertake internal audits each year. Audit review outcomes, and any required actions, are presented to and monitored by the Audit Committee (a sub-Committee of the Board). This provides our directors and management assurance as to the existence and strength of the controls implemented.

Legislation & frameworks	Authorities	Key business plans
• National Gas Law • National Energy Retail Rules • Gas Industry Act 2001 • Gas Safety Act 1997 and associated Regulations • Distribution Licence • Gas Distribution System Code • Safety Case • Industry Standards	• Essential Services Commission of Victoria (ESCV) • Australian Energy Regulator (AER) • Energy Safe Victoria (ESV)	• Vision & values • Asset Management Strategy • Asset Management Plan • Asset Strategies • IT Investment Plan • Distribution Mains and Services Strategy • Metering Strategy • Risk Management Framework

9 Capital expenditure

Our capex proposal focuses on maintaining strong safety and reliability, connecting new customers who want to connect and preparing our network for a decarbonised future.

IN THIS CHAPTER:

- **We will invest $722 million in the next AA period, which is 54% higher than current levels due to increased investment in mains replacement .**
- **We are undertaking 820 km of proactive mains replacement, including 704 km of low pressure mains replacement, 86 km of first generation HDPE class 250 mains and 30 km of medium pressure steel.**
- **We will connect a further 36,000 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 maintaining 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 $722 million in the next AA period, which is 54% ($253 million) higher than what we expect to incur in the current AA period (see Table 9.1).

This is $28 million lower than the $750 million proposed in our Draft Plan reflecting a reduction in the length of low pressure mains replacement, updated gross connection numbers and refinement and scaling back on programs in line with stakeholder feedback.

The increase from the current AA period is driven by a step up in the costs of our low pressure mains replacement program, around 120 km of replacement of at risk earliest generation polyethylene and medium pressure steel mains, as well as higher IT capex requirements. Meter replacement and other capex are also forecast to increase, with growth, augmentation and telemetry capex forecast to decrease in the next AA period.

We will continue the low pressure mains replacement program at the current replacement rate of around 140 kilometres per annum, targeting completion of the program in the subsequent AA period.

The program to date has delivered considerable safety and reliability benefits (through fewer leaks and instances of water-in-mains events) and has also reduced carbon emissions at the end of the current AA period by 35,000 tonnes of CO_2-equivalent per year compared to 2017 levels.

Continuation of the program in the next AA period will ensure safety is maintained as these assets continue to degrade. It will also improve reliability performance during wet weather

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

Priority	Current AA period	Next AA period	Highlights
Mains replacement	206.7	424.8	✓ Continuation of our low pressure mains replacement program (704 km) including high pressure backbone augmentation to facilitate the prioritised replacement, proactive replacement of early generation polyethylene mains (HDPE Class 250, 86 km) and medium pressure small diameter steel mains (30 km)
Growth assets	128.1	115.8	✓ Connection growth in line with independent dwelling growth forecasts and government policy
IT	47.5	73.9	✓ Maintaining existing systems and infrastructure ✓ Major upgrade of our Enterprise Resource Planning (ERP) system ✓ New investment in digital customer experience
Meter replacement	15.9	23.7	✓ Continued replacement of time expired meters when they fall due ✓ Remote meter reading for hard to read meters
Augmentation	18.0	9.1	✓ Augmentation to Doncaster, Vermont and Tooronga networks
Telemetry	5.0	4.7	✓ Maintaining SCADA network
Other assets	19.6	32.9	✓ Complete alterations on a number of our transmission pipelines ✓ Maintaining and replacing cathodic protection, regulators, valves, plant and equipment ✓ Hydrogen readiness expenditure to prepare our network for the decarbonised future
Escalation	-	5.7	✓ Real cost increases in labour inputs
Overheads	27.6	31.0	✓ Network planning, technical assurance and engineering support associated with delivering the capital program
Total	**468.2**	**721.6**	

events and is expected to reduce carbon emissions on our network by over 70,000 tonnes of CO_2-equivalent per year once completed. As already mentioned, we are also proposing to replace around 120 km of other at risk mains to ensure we can maintain current levels of safety and reliability.

We expect slower growth compared to previous periods which sees a decrease in new connections capex.

The capex forecast also includes a small amount (around 1.3% of total spend, down from 2.7% in the Draft Plan) over the next five years to support the transition of the network to a decarbonised future and reflects joint work undertaken with the Australian Hydrogen Centre (AHC). This work confirmed that the network of distribution assets, including pipes and other associated assets are largely hydrogen ready, with only minimal additional expenditure required to update procedures, test existing pipeline welds, replace incompatible equipment in hazardous areas with higher rated equipment and further compatibility studies.

Since our Draft Plan, further analysis suggests that some materials and components we previously thought may be incompatible are now confirmed to be compatible with hydrogen blends.

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, with overheads and escalation calculated separately, unless otherwise stated. Costs have been updated with the latest inflation forecasts and unit rates to reflect a more up to date estimate from the Draft Plan.

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.[28]

Forecast capex must also satisfy various additional criteria,[29] including:

- maintain and improve safety;
- maintain integrity;
- 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.[30]

9.2 Customer and stakeholder engagement

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

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

9.2.1 Customers

Across all three of the Victorian gas distribution networks, 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 told us they value their current gas supply and expect levels of public safety and reliability to be maintained. 91% of customers who participated in our workshops supported accelerating the mains replacement program to ensure we maintain our safety and reliability performance.

Customers value and feel empowered by access to digital communication options. 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 and customer service 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. 90% of customers in our workshops supported the proposed digital services package in our Draft Plan, inclusive of SMS, at an additional price of $1 per annum. More information on our plans to enhance our digital communications with customers can be found in section 9.5.3.

There was some interest from customers in new digital ways to manage their gas usage and reduce their bills. We discussed potential digital metering options with customers (technologies and likely costs) and asked what benefits they would see from more digital metering. Making gas usage more efficient is most important to customers. In fact, customers' top three priorities with respect to smart metering and their usage are to make usage more efficient (50%), to get notified when usage has changed (42%) and not to have estimated bills (41%). Many customers cited the ease by which they can monitor their electricity usage, and wanted the same opportunity with their gas supply.

Customers were supportive of our proposal to install remote read meters for hard to read meters, and introduce new options for self reads and fact sheets on typical appliance usage and running costs. More details on our remote metering program can be found in section 9.5.4.

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[28] NGR 79(1)
[29] NGR 79(2)
[30] NGR 74

Table 9.2: Customer and stakeholder insights for our capex plans

What we heard	Our response
• Customers trust our track record of strong safety and reliability performance, with 91% of customers supportive of our approach to accelerating mains replacement. • Stakeholders have indicated a preference for discretionary capex to be minimised and some were undecided on support for parts of our capex proposals (e.g. growth capex and mains replacement) given the uncertain policy position. • Stakeholders want to understand in more detail the risks and safety drivers for mains replacement. • 89% of customers who participated in our workshops were supportive of our proposed approach to preparing our networks for renewable gas. • Stakeholders welcome the reduction in our proposed hydrogen readiness expenditure based on draft plan feedback but were undecided on support for our plans given policy uncertainty. • 90% of customers in our workshops supported the proposed digital services package, of which 65% strongly supported. • Stakeholders are generally supportive of our plans to meet customers' communication expectations, which have shifted to more digital preferences. • We received limited detailed feedback on IT-related aspects of our plans. Stakeholders welcome the benefits of consolidating the IT environments across AGIG.	Our capex proposal has been developed to improve current levels of safety and reliability. An important aspect of this is low pressure mains replacement. Section 9.4 explains how we have developed our capex forecasts. Our review processes in terms of risk, cost, deliverability and efficiency ensure discretionary capex is minimised. We recognise there is policy uncertainty and have used the most up to date information available to inform our proposals. We note we must continue to maintain and invest in our network to ensure we meet our safety and reliability obligations and deliver on the expectations of our customers. As is current practice, we only connect new customers who want to connect to our network. We also undertake an economic test for all new connections to ensure it is economic to do so (i.e. beneficial to existing customers). An upfront charge is applicable to cover any shortfall. For most new connections we find the payback period is around six years. We have reduced our proposed low pressure mains replacement from 800 km in our Draft Plan to 704 km, which is consistent with our current run rate of around 140 km per annum. Our Distribution Mains and Services Strategy is provided in Attachment 9.7 to this Final Plan. The strategy details the performance and ongoing safety risks of mains across our network, the risk treatment options available and justification of the proposed replacement program in the next AA period. Our Hydrogen Network Readiness Strategy is provided in Attachment 9.10 to this Final Plan. It sets out in more detail the drivers and support for our proposed hydrogen readiness activities in the next AA period. We have also addressed a number of stakeholder queries on our hydrogen readiness activities in earlier chapters of this Final Plan. Our IT Investment Plan (Attachment 9.9) and IT Business Cases (Attachment 9.19) provide more detail on our proposed IT capex including our digital customer experience and AGIG One IT programs. We will continue to engage on our capex plans during our post-lodgement engagement program.
Final Plan Outcome	
Our capex proposal will ensure we can improve safety and reliability performance, continue to meet customer service expectations (including by providing more services digitally) and economically connect new customers. Our proposal also takes small steps towards preparing our network for a decarbonised future. Following refinement of our plans, we have reduced our proposed capex by around $28 million. This Final Plan provides detailed supporting information to support our proposed capex programs (see Attachments 9.1 – 9.19).	
Customers were highly supportive of our capex plans, including efforts to prepare the network for renewable gas.	
Stakeholders found it difficult to accept and were undecided on some parts of our capex plans because of policy uncertainty.	

Customers told us we need to move towards cleaner energy supply to protect our planet and future generations. 89% of customers who participated in our workshops were supportive of our proposed approach to preparing our networks for renewable gas.

Our proposed hydrogen readiness expenditure is discussed further in section 9.5.7.

9.2.2Stakeholders

Stakeholders are supportive of maintaining safety and reliability. However, throughout our consultation process, stakeholders emphasised that discretionary capex should be minimised to ensure customers are paying no more than they need to on their bills. This was considered particularly important to stakeholders given the environment of uncertainty both in relation to the future of gas and the external environment which has seen sharp increases in the costs of labour, capital and materials and more recently the retail price of gas.

Stakeholders want to understand in more detail the risks and safety drivers of our proposed mains replacement programs.

Feedback was also provided by stakeholders on our customer growth forecast. Stakeholders felt that the forecast should consider factors such as consumption trends and any potential policy that may arise regarding the connection of new customers in the next AA period.

Our new connections forecast has regard to the most up to date information available for new housing starts and connection trends. This is discussed further in Chapter 13.

Stakeholders raised a number of questions on our proposed hydrogen readiness expenditure, including:

- is now the right time to be undertaking hydrogen readiness activities;
- can there truly be 'no regrets' actions given there is no clear policy pathway for hydrogen;
- does the proposed expenditure cover the 10% hydrogen blend only, or is it applicable to 100% hydrogen; and
- is it compatible with our accelerated depreciation proposals?

More information received through the Australian Hydrogen Centre (AHC) has resulted in reductions to our proposed hydrogen readiness expenditure compared to our Draft Plan. The proposed activities are discussed further in section 9.5.7.

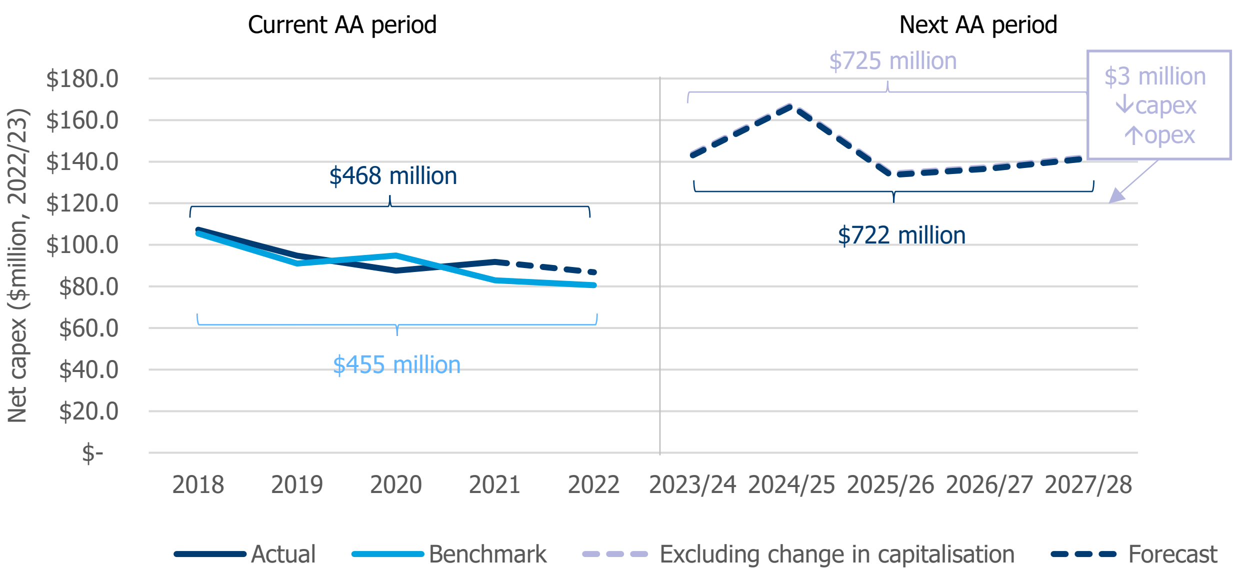
We have also addressed a number of these stakeholder queries on our hydrogen readiness activities in earlier chapters of this Final Plan.

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. We are forecasting an increase in capex in the next AA period driven by an increase in the costs of our low pressure mains replacement as we move into higher density and

Figure 9.1: 10 year capex



more complex areas, along with higher IT capex requirements.

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.

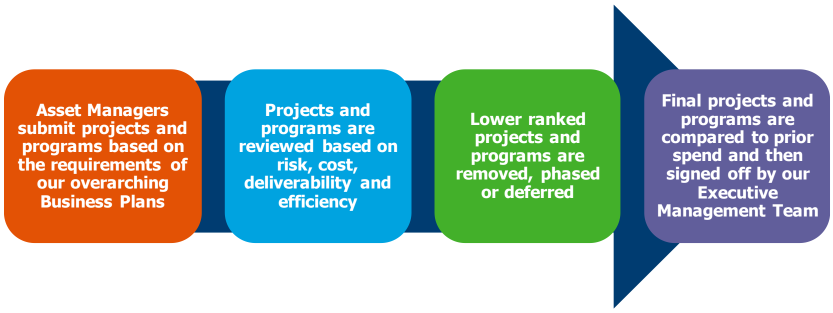
Mains replacement will continue to be a key focus in the next AA period. While replacement will continue at current rates, we are moving into higher density and more complex areas.

We will undertake a significant upgrade of our ERP system, and complete modification and inline inspection on a number of our transmission pipelines.

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

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

Figure 9.2: Summary of capex planning process



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, asset strategies, 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 and asset strategies updated for the higher ranked projects and programs 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.

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 – domestic new mains and industrial and commercial (I&C) new mains;
  - Services – new domestic services and new I&C services; and
  - Meters – new domestic meters and new I&C meters;
- Meter Replacement – periodic meter change (PMC) (domestic and I&C meters); and
- Mains Replacement – block replacement of low pressure cast iron and other materials (by suburb), High-Density Polyethylene (HDPE) 250 replacement, medium pressure steel 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, telemetry and other capex projects and programs. Each project or activity is supported by a business case or asset strategy.

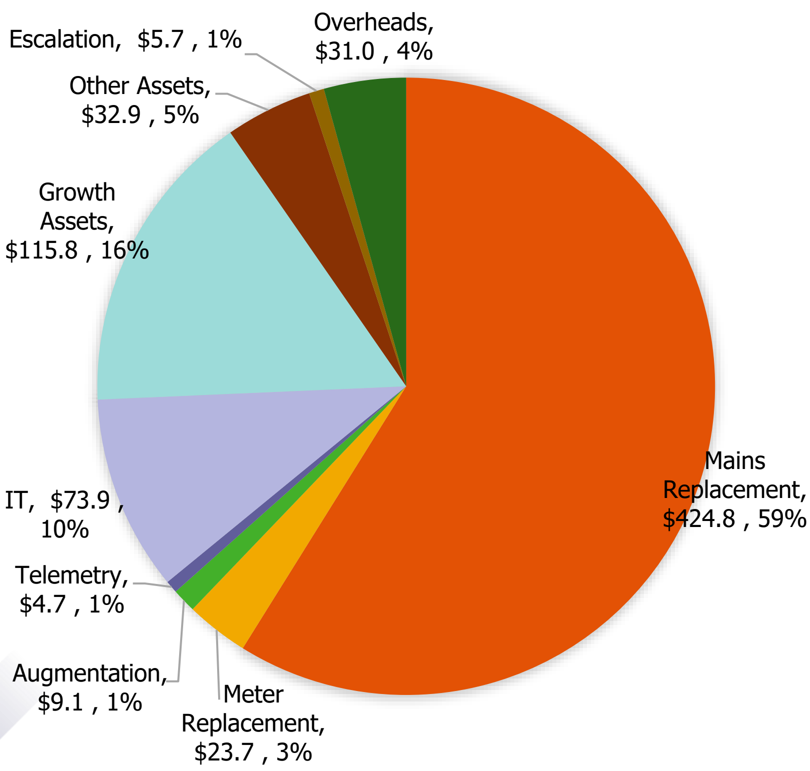
Forecast costs for these works may be based on tender or contract information, current actual or historical costs for similar works or specialist engineering estimates.

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.

Since our Draft Plan we have updated the inputs for forecast inflation and real labour cost escalation with the latest available information. Of particular note, recent inflation numbers have been much higher, contributing to an increase in our capex forecasts of around $34 million compared to our Draft Plan.

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



9.4.4 Capitalised overheads

We undertake network planning, technical assurance and engineering activities within our business that contribute to the delivery of our capital program. The costs of these activities and services are capitalised and applied as a capital overhead across the program.

As discussed in Chapter 8, we have proposed to reduce the scope of activities and support services that are capitalised as an overhead across the program.

On average, 70% of overhead costs of these activities are fixed and 30% 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 $31 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, asset strategies and individual business cases. These business plans, asset strategies and business cases assess the options considered to address the identified issue, the estimated cost of each option, the untreated and residual risk each option would result in and alignment with both our vision and the capex requirements of the NGR.

These business plans and business cases can be found in Attachments 9.7 – 9.19 of this Final Plan.

9.5.1 Mains replacement

Our mains replacement program remains a key focus in the next AA period. It is the single most important activity we undertake to ensure public safety.

Low pressure (LP) cast iron mains continue to be a safety and reliability concern. The continuation of LP mains replacement in the next AA period will improve safety and reliability outcomes for customers. We are also looking to replace a smaller volume of at risk earliest generation high density polyethylene and medium pressure steel mains.

We will invest $424.8 million to:

- Continue the replacement of remaining low pressure cast iron and other interspersed mains – a further 704 km in addition to the 607 km LP and 29 km MP cast iron and other interspersed mains we will have replaced in the current AA period. Replacing 704 km is equivalent to carrying forward the rate of mains replacement achieved in the first four years of the current AA period. The final year of the current AA period is lower to manage overall investment levels under the CESS, and focus resources on completion of the AGN program. We aim to replace all remaining low pressure cast iron and other interspersed mains in the network in the subsequent AA period. This represents a significant safety milestone for our business and our customers;
- Replace 86 km of high-risk early generation plastic piping (HDPE 250) which has become brittle, cannot be maintained and is now end of life;
- Replace 30 km of high-risk medium pressure steel in the Mount Waverley area which are exhibiting higher leak rates as a result of corrosion; and
- reactively replace customer services as required.

Other mains replacement activities captured under our opex in the next AA period are:

- reactive or piecemeal replacement of sections of mains as issues arise; and
- HDPE 575 study – collection and assessment of 100 samples of HDPE 575 mains from across each distribution area, along with other Victorian gas distribution businesses, Deakin University and the Future Fuels Cooperative Research Centre (CRC), to test the life expectancy of these mains throughout Victoria and Albury based on their integrity and squeeze off points.

This totals 820 km of mains replacement forecast for the next AA period. This is a higher volume than the 638 km we will complete in the current AA period, but a lower volume than the 914 km proposed in our Draft Plan. We are able to deliver this higher volume efficiently due to the roll-off of mains replacement from other networks.

Following stakeholder feedback on our Draft Plan, we have brought the low pressure volumes back in line with current annual replacement rates.

Consistent with our Draft Plan, we are forecasting higher average costs across the mains replacement program. This is because we are moving into more higher density areas which are more complex compared to the areas completed in the current period.

Further detail on our mains replacement program can be found in our Distribution Mains and Services Strategy which is provided at Attachment 9.7 to this Final Plan.

9.5.2 Growth

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, although in lower numbers than they have in the current 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.

Through our workshops our customers told us they consider gas plays a critical role in the state, particularly in the provision of home heating in the colder months in Victoria.

We will invest $116 million to connect around 36,000 new residential and business customers over the next AA period. This includes new homes and businesses in greenfield developments in the South Gippsland region and in-fill developments across our inner metropolitan network.

This is an increase of $36 million compared to our Draft Plan, driven by an increase in the volume of connections from 29,000 to 36,000, and updates to unit rates for new connections to reflect most recent actual cost information.

The calculation of forecast gross connection volumes by type can be found in our Capex Forecast Model provided in Attachment 9.3 to this Final Plan. Support for the forecast unit rates for new connections is provided in the Unit Rates Report at Attachment 9.6.

Our new connections forecast is based on independent forecasts for new home starts, recent trends around how many new homes connect to the gas network, as well as existing policy measures to incentivise electrification. We have used the most up to date information available for each of these factors.

More information on new connections and our demand forecast can be found in Chapter 13.

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 customers 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;
- The connection assets installed for new customers are renewable gas ready; and
- Gas networks are inherently reliable, with an average unplanned outage of once every 40 years. This compares to an average of one a year for electricity networks.

9.5.3 IT

We will invest $74 million in IT over the next AA period. This is $3 million lower than our Draft Plan, and $26 million higher than our forecast spend of $48 million in the current AA period.

The uplift compared to the current period is driven by a $35 million major program of work required to upgrade our ERP, billing and asset management systems to a new platform as the existing platform is being retired and will no longer be supported from 2024.

We will invest $32 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 requirements such as the amendments to the *Security of Critical Infrastructure Act 2018* (Cth) and increasing cyber threats) and to replace end-of-life IT devices and infrastructure.

We are also proposing to invest $7 million to:

- improve information management;
- support remote digital metering; and
- provide a better and more accessible digital customer experience.

More information on our proposed IT capex can be found in our IT Investment Plan and IT Business Cases at Attachments 9.9 and 9.19 to this Final Plan.

9.5.4 Meter replacement

Customer meters measure the amount of gas delivered, which forms a key component of each gas bill. We undertake time expired meter replacement 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 around 170,000 meters over the next AA period at a total cost of $23 million. This is higher than what we are spending on time expired meter replacement in the current AA period, driven by asset age and higher average costs of this work. We have used a consistent forecasting approach to determine the number of time expired meter replacements required.

Consistent with our Draft Plan, we will also replace 5,650 hard to read meters with new meters which can be remotely read. We first implemented a remote meter reading solution at Kew Cottages late last year. As reading these meters posed a safety risk for meter readers we were having to bill based on estimated reads. We will continue with this solution for other critical hard to read sites to remove estimated meter reads for these customers and improve health and safety outcomes for our personnel.

We will also explore an opt-in fee-for-service remote reading solution for all customers. This would allow any customer to opt-in to a remote read metering solution by paying for the upfront and ongoing incremental cost of a new digital meter.

Customers raised smart and digital metering options as an area of interest at our customer workshops. Customers felt they don't want estimated reads, notifications on usage changing and to make their usage more efficient.

Lastly, we will explore more options for customers to submit self reads which can be counted as actual reads for compliance purposes and provide more information materials for our customers about typical usage and running costs for different appliances. This is a low cost way to respond to customer feedback that they want to better understand how much gas they are using and make their usage more efficient.

More information on our meter replacement activities can be found in our Metering Strategy provided as Attachment 9.8 to this Final Plan.

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 will invest $9 million in augmentation projects in the next AA period. This is $11 million lower than our Draft Plan, and $9 million below the $20 million we are forecast to spend in the current AA period. The decrease has been driven by refinements to the scope and costs of works that make up the program, including incorporating the high pressure backbone augmentation to facilitate the prioritised replacement of low pressure mains as part of the low pressure mains replacement program.

In the Doncaster, Vermont and Tooronga networks, we will reinforce existing HP mains and upgrade regulating stations to ensure we can maintain minimum operating pressures across these networks which are reaching capacity constraints.

More information on our augmentation projects can be found in our Network Capacity Strategy provided as Attachment 9.11 to this Final Plan.

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 $5 million to replace end of life SCADA equipment and install additional pressure monitoring points to ensure we can continue to collect appropriate pressure information from the network as it grows and changes. More information on our telemetry projects can be found in our SCADA Strategy provided as Attachment 9.12 to this Final Plan.

9.5.7 Other assets

We will invest $33 million on other assets in the next period. This is $11 million lower than in our Draft Plan, primarily driven by a reduction in our hydrogen readiness activities.

Two large investments in the next AA period are:

- $11 million to complete modifications of our higher-pressure transmission mains to allow inline inspection in accordance with accepted good industry practice; and
- $9 million to make the network ready for Hydrogen distribution which includes updating procedures, testing of existing pipeline welds, replacement of incompatible equipment in hazardous areas and further compatibility studies.

We will continue to replace end-of-life regulators, valves and cathodic protection equipment.

We will also replace small plant and equipment based on the age and condition of these assets, as well as any changing business requirements.

Hydrogen Readiness

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

In particular, and relevant to our capex investment in the next AA period, is making sure our network is ready for hydrogen blending. Our proposed hydrogen readiness activities will ensure our network is ready and is not a roadblock for a possible renewable gas 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 findings of these studies to date have been used to inform our hydrogen readiness activities over the next AA period. To this end, we are proposing $9 million of investment in the next AA period to:

- Bring sites up to a higher hazardous area classification standard ($6 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 ($3 million); and
- a further $0.2 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.

- More information on our hydrogen readiness activities can be found in Attachment 9.10 Renewable Gas Adaptation Plan.

9.5.8 Escalation and overheads

Our total capex forecast for the next AA period also includes $6 million of real cost escalation and $31 million of capitalised overheads.

9.6 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.

9.6.1 Mains replacement

Our mains replacement program is the largest driver of our capex in the current AA period, and as outlined above will become an even larger component and focus in the next AA period. It is the single most important activity we can undertake to ensure public safety.

In the current period, we will invest $208 million to replace 638 km of old low-pressure cast-iron, unprotected steel and other mains. These low-pressure mains were identified as representing a high risk to public safety. As agreed with our technical regulator, ESV, we are on track to complete the replacement of 608 km of low pressure cast iron and other mains, 30 km of medium pressure cast iron and other mains and a small 2km section of HDPE 250 mains by the end of December 2022.

This volume of activity is exceeding our commitment to the AER in our last AA submission to replace a total of 531 km of low pressure and 12 km of medium pressure materials. We have been able to replace more mains each year within the benchmarks set in the current AA by efficiently packaging works and implementing a panel arrangement for contracting these works, achieving favourable unit rate outcomes. The 2 km of Early Generation HDPE 250 we will replace in the current AA period will inform the larger replacement program of 86 km proposed for the next AA period.

9.6.2 Growth

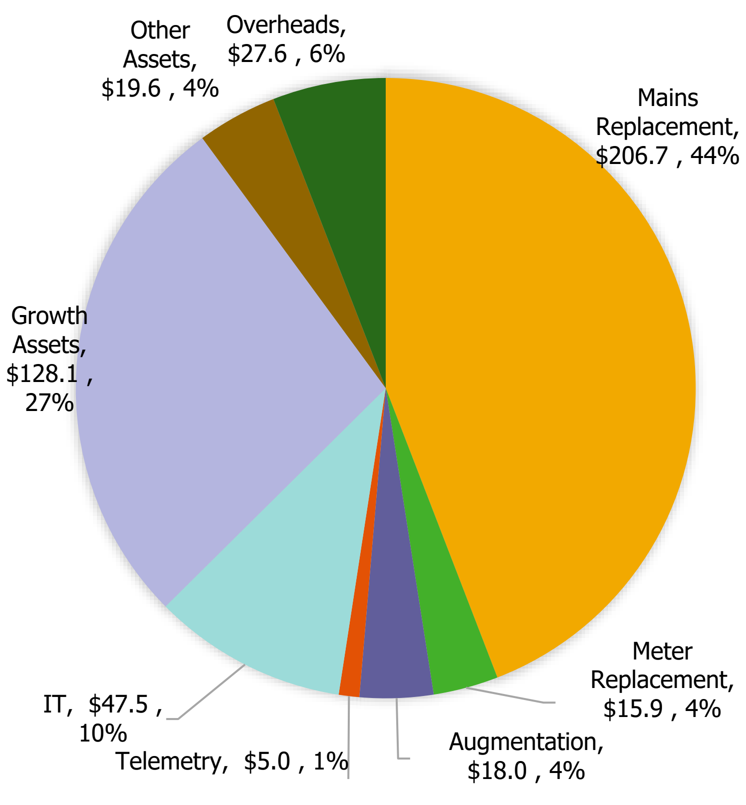
In line with our vision of delivering profitable growth, we will invest $128 million to connect around 45,000 new residential and business customers to our distribution network over the current AA period. This includes new homes and businesses in greenfield developments and extensions in our South Gippsland network and knockdown rebuilds and other brownfield developments within our metropolitan network (infill).

9.6.3 IT

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 will invest a total of $48 million, which has been focused on separating our major IT applications from United Energy, building a new Network Control Centre, additional investment in our data centre, undertaking a large upgrade of our Geospatial Systems and

Figure 9.4: Capex by driver in the current AA period



continuing to leverage the capability of our systems through our application renewal program. This is slightly above our approved allowance for the period driven largely by the separation project.

9.6.4 Meter replacement

We undertake time expired meter replacement 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 122,000 meters to December 2021 and forecast we will have replaced a further 16,000 meters by the end of December 2022 at a total cost of $16 million over the five years. This is above our allowance of $9 million due to a higher actual unit rate cost incurred for domestic meter replacements driven by a greater proportion of new compared to refurbished meters required to be installed (where new meters are more expensive than refurbished meters).

9.6.5 Augmentation

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 will invest a total of $18 million in augmentation, including projects in Oakleigh, Toorak and Lang Lang.

9.6.6 Telemetry

In the current AA period we will invest just under $5 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.

9.6.7 Other assets

We will invest $20 million on other assets in the current AA period. This includes modifications to some of our higher pressure transmission pipelines in preparation for in line inspection, replacing end-of-life regulators, valves and cathodic protection equipment, as well as replacement of small plant and equipment based on the age and condition of these assets, and any changing business requirements.

9.6.8 Overheads

We forecast a total of $28 million in capitalised overheads in the current AA period.

9.7 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;
- improve safety and reliability for customers in areas of our network that still have low pressure cast iron and other material mains;
- connect new customers to our network where it is commercially and economically viable to do so;
- assist the transition of our network to support the delivery of renewable gases; and
- continue to provide the level of customer service that our customers require and expect.

The projects and programs we intend to deliver are described below.

- Continuing our mains replacement program, specifically we will;
    - continue the replacement of low pressure cast iron and other pipes (704 km, $383 million), working towards a significant safety milestone for our customers and our business to remove all these mains in the following AA period;
    - replace the highest risk, early generation HDPE 250 plastic piping (86 km, $42 million);
    - replace high risk medium pressure steel mains in Mount Waverley (30 km, $15 million); and
    - undertake opex activities such as reactive replacement when needed and an investigation program to understand the condition and remaining life of first generation HDPE 575 plastic pipes across Victoria, these mains having been the cause of major incidents in other states.
- Continuing our meter replacement program ($23 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 metropolitan networks ($9 million) to support the continued infill growth and maintain reliability for existing customers.
- Replacing end-of-life telemetry ($5 million) which is critical to operating and monitoring our network.

- Ensuring our IT systems and infrastructure are current, fit-for-purpose and meet legal obligations by:
  - maintaining and undertaking regular upgrades of our current applications, replacing end of life infrastructure and devices, and uplifting cyber capability ($32 million);
  - upgrading our end of life ERP, billing and asset management systems ($35 million);
  - and implementing new technologies for our business and our customers where there is an overall benefit or service improvement ($7 million).
- Connecting around 36,000 new residential and industrial customers to our network over the five years to June 2028 ($116 million).
- Completing modification of our ageing transmission pipelines to allow for inline inspections where possible ($11 million) and other system works such as replacement of valves, regulators and cathodic protection systems, and maintaining plant and equipment ($20 million).
- Undertaking moderate hydrogen readiness activities to support the network in the transition to renewable gases including to update procedures, test existing pipeline welds, replace incompatible equipment in hazardous areas with higher rated equipment and further compatibility studies ($9 million).

These projects and programs are broadly aligned to our track record over the current AA period, with mains replacement in higher density and more complex areas, and major IT works driving a $253 million (or 54%) increase in our total forecast capex compared to 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 so all customers who want gas and are economically viable to connect can connect (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.**

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 $1.4 billion to $1.9 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 Final Plan.

Our forecast depreciation has been determined using the standard approach applied by the AER in its regulatory decisions but includes an additional $76 million depreciation. The accelerated depreciation reflects the outcome of our Future of Gas project, which is described in Chapter 6 of this Final 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 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 MGN that otherwise would have occurred if actual information for 2017 were available.

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 Final Plan and

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	1,192.9	1,250.2	1,297.6	1,330.1	1,337.9	1,395.1
Less Depreciation	-62.9	-66.3	-70.2	-72.4	-77.9	-62.8
Plus Conforming Capex	97.1	87.7	82.1	84.8	83.7	47.7
Plus Actual Inflation	23.1	26.0	20.7	-4.6	51.5	29.3
Less 2017 Capex Adjustments	N/A	N/A	N/A	N/A	N/A	-7.2
Less Funding Adjustment	N/A	N/A	N/A	N/A	N/A	-1.9
Closing Value	**1,250.2**	**1,297.6**	**1,330.1**	**1,337.9**	**1,395.1**	**1,400.2**

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
Transmission and distribution	89.3	105.1	88.7	98.2	100.4
Services	23.0	20.7	20.2	20.3	20.3
Cathodic Protection	1.2	1.1	1.0	1.0	1.0
Supply Regs/Valve stations	1.9	1.3	1.1	1.4	1.4
Meters	7.0	7.6	8.0	9.8	10.9
IT	19.4	31.0	13.5	5.5	9.1
SCADA	1.3	1.0	1.0	0.9	0.8
Other	3.3	2.2	3.5	2.9	1.0
Closing Value	**146.3**	**169.9**	**136.9**	**140.0**	**144.9**

Table 10.3: Summary of Lives Used to Calculate Depreciation

Asset Category	Standard Useful Life (years)
Transmission and distribution	50
Services	50
Cathodic Protection	50
Supply Regs/Valve stations	50
Meters	15
IT	5
SCADA	15
Other	10

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	96.5	94.4	98.8	105.2	109.6

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

Our approach to depreciation is the outcome of work undertaken as part of the Future of Gas project, which is described in Chapter 6 of this Final Plan. We have applied the standard approach to determining depreciation but have also sought to bring forward an amount of $76 million ($2022/23) depreciation arising from our Future of Gas work.

The intent of the Future of Gas project was to identify the potential pathways for our networks under four possible de-carbonised energy futures, ranging from full electrification to displacement of natural gas with renewable gas and then to examine the consequences of each pathway on price, options for flexibility for our customers and asset stranding risk. The project showed that these three things are inter-related; sharp price rises reduce options for future customers and ultimately lead to some degree of asset stranding risk. It also showed that we could use prudent acceleration of depreciation to lead to better price paths for customers, which preserve options for them, and to allow us to reduce asset stranding risk.

The AER have recognised in their information paper "Regulating gas pipelines under uncertainty" that it may be appropriate for regulated gas networks to assess these future risks arising from the decarbonisation of the national energy supply over the coming decades and apply potential remedies now which will mitigate future risks and provide for stable prices for customers over the long term.

We consider our approach meets this objective, as well as the efficiency goals set for depreciation under the NGR.

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.

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	96.5	94.4	98.8	105.2	109.6
Less Inflation	42.7	45.7	49.6	52.6	55.8
Regulatory Depreciation	**53.8**	**48.7**	**49.2**	**52.6**	**53.8**

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	1,400.2	1,498.0	1,628.0	1,726.5	1,829.5
Less Depreciation	-96.5	-94.4	-98.8	-105.2	-109.6
Plus Conforming Capex	151.5	178.8	147.7	155.7	166.2
Plus Actual Inflation	42.7	45.7	49.6	52.6	55.8
Closing Value	**1,498.0**	**1,628.0**	**1,726.5**	**1,829.5**	**1,941.9**

Note: Totals may not add due to rounding.

Forecast inflation is also used in determining the total revenue that we can recover (and hence the prices we can charge). This is reflected in the methodology that the AER uses to determine our total revenue, which relies on inflation to determine the following two costs:

- Return on capital – which is calculated by multiplying a nominal rate of return (see Chapter 11) by the nominal capital base determined in this section (where a nominal value includes the impact of inflation); and
- Regulatory Depreciation – which is calculated by deducting from forecast straight-line depreciation (see Table 10.5) the forecast inflation adjustment applied to the capital base.

The AER removes inflation in determining regulatory depreciation to essentially remove the additional compensation for inflation in determining the return on capital, which arises from multiplying a nominal rate of return by a nominal capital base (referred to as a double count of inflation).

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 3.05%. This will be updated with the AER's Final Decision.

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. We have created a new asset class called Future of Gas which will be depreciated over the next AA period, reflecting the rapid transition in the energy sector going forward. There is $76 million ($2022/23) additional depreciation proposed in the next period.

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 $1,942 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 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 $1.4 billion investment in the Multinet 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 Final Plan, but our Final Decision from the AER will incorporate the AER's 2022 Rate of Return Instrument.**
- **Based on forward market estimates, the rate of return is 5.1% (compared to 5.7% at the start of the current period).**
- **We are expecting financing costs to remain stable in the next AA period.**

In this Final 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 provide a framework for calculating the return on the projected capital base (rate of return). The AER's Rate of Return Guideline 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 2018 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 6.67% over the next AA period (see Table 11.1).

These values are indicative and were measured using April 2022 information.

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.[31] 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, however the AER will apply this instrument in its Final Decision for MGN.

11.2.2 Return on Debt

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.

Table 11.1: Indicative return on equity

Parameters	Value
Equity risk-free rate	3.01%
Beta	0.6
Market Risk Premium	6.10%
Return on equity	**6.67%**

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 4.09%, which we have applied in this Final 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 (6.67%) and return on debt (4.09%) results in an overall average rate of return of 5.13%. 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 Final Plan. Our cost of tax building block is based on an assessment of our taxable income, the applicable corporate tax rate and the value of imputation credits (gamma) to equity holders. These matters are discussed in this section.

The result of following the AER's approach to tax is that our tax building block averages $4.0 for each year of the next AA period.

11.3.1 Calculating the Cost of Tax

We have determined the cost of tax as total revenue less opex, tax depreciation and interest expense; where:

- *Total revenue* – which is the sum of all of our costs (or building blocks) (see Chapter 12);

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

- *Opex* – which is a specific building block that is used to determine total revenue (see Chapters 8 and 14);
- *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 Guideline. 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.

These changes, to the extent that they were not previously used by MGN, 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 $793 million ($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).

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	793.4	912.9	1,034.7	1,104.2	1,180.9
Plus gross capex	153.5	180.5	149.8	157.8	168.3
Less tax depreciation	-34.0	-58.7	-80.3	-81.1	-86.9
Closing tax asset base	**912.9**	**1,034.7**	**1,104.2**	**1,180.9**	**1,262.4**

Note: totals may not add due to rounding

11.4 Summary

Our financing and tax costs collectively account for around 39% of our total costs. For the purposes of this Final Plan, we have applied the AER's Rate of Return Guideline and the AER's Tax Review in determining our financing and tax costs.

This results in an average rate of return of 5.13% (see Table 11.3) and a Net Tax Allowance of $20 million. These values will be updated in the AER's Final Decision in the second quarter of 2023.

Table 11.3: Indicative AER Rate of Return and Gamma

Parameters	MGN Final Plan
Return on Equity	6.67%
Return on Debt	4.09%
Gamma	0.585
Overall Rate of Return	**5.13%**

12 Incentives

We will continue to seek out efficiencies and maintain strong performance under the existing opex and capex efficiency sharing schemes. We are not proposing to introduce any other new schemes at this time.

IN THIS CHAPTER:

- **We are forecasting a total efficiency carryover of $1 million in the next AA period from the operation of the opex efficiency carryover mechanism (ECM) 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 have decided not to propose a new Gas Network Innovation Scheme (GNIS) at this time.**

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 carryover mechanism (ECM) and the contingent capex efficiency sharing scheme (CESS), both of which we propose continue.

During customer workshops, our customers told us they see innovation as an enabler to transition towards cleaner energy, and more affordable and safe gas supply. In our Draft Plan we proposed the introduction of a gas network innovation scheme (GNIS) to provide a more adaptable and fit-for-purpose funding mechanism for innovation projects. The scope and form of the scheme was shaped by a joint engagement program with AusNet, Jemena, our customers and stakeholders.

There was strong support for dedicated innovation funding from customers. 90% of workshop participants supported funding between $1 and $2 per customer per annum, with decarbonisation/net zero and safety and reliability the two most commonly prioritised focus areas for innovation projects.

Some stakeholders, however, were not supportive of a dedicated GNIS proposal, questioning whether there were existing mechanisms in place to fund innovation expenditure for gas networks and whether it was consistent with our accelerated depreciation proposal.

We have decided not to propose a new GNIS at this time. We will continue to look for ways we can innovate and deliver benefits to our customers through existing mechanisms (such as the Australian Hydrogen Centre, Future Fuels Cooperative Research Centre or partnering with governments).

We reiterate our Draft Plan position that we will not propose a customer service incentive scheme because our customer satisfaction scores are improving, reaching the highest score to date for MGN in 2021 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 provides for incentive schemes to apply to encourage the efficient provision of services.[32]

The NGR also requires any incentive mechanism to be consistent with the revenue and pricing principles, the most relevant of which is the principle that a service provider should be provided with effective incentives to promote:

- efficient investment in (or in connection with) the network;
- the efficient provision of services; and
- the efficient use of the network.[33]

The AER is currently undertaking a review of incentive schemes for regulated networks. We have reflected on the AER's Discussion Paper where we can in this Final Plan. The AER is expected to publish draft positions in July 2022 and final positions in September 2022. We note these may influence the schemes that apply to our network in the next AA period.

12.2 Customer and stakeholder engagement

A summary of customer and stakeholder views on incentives and how we are responding is provided in Table 12.1 below.

Table 12.1: Summary of customer and stakeholder feedback

What we heard	Our response
• Customers view innovation as an enabler to transition cleaner energy. They are supportive of innovation funding to trial new ideas and technology. • 90% of customers who attended our workshops support at least some level of innovation funding. • Some stakeholders were not supportive of the proposed GNIS, with questions around whether there are existing (and potentially more appropriate) mechanisms in place to fund innovation expenditure for gas networks and whether the GNIS was consistent with our plans for accelerated depreciation.	We maintain our Draft Plan positions on the ECM and CESS. We have updated the Contingent CESS API for latest performance. We have decided not to propose a GNIS at this time and therefore have removed the GNIS from our Final Plan.
Our incentives proposal will maintain existing incentives to seek out efficiencies and maintain strong performance. Following refinement of our plans, we have not proposed the introduction of a new Gas Network Innovation Scheme at this time.	
Customers were supportive of our plans to invest a small amount into innovation spending.	
Stakeholders were less supportive of our innovation scheme proposal and support its removal.	

[32] NGR 98
[33] NGL 24(3)

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.

In engaging on our Draft Plan, we presented a potential new GNIS with dedicated funding in the order of $5 – 7.5 million over the next AA period set aside for innovation projects. We discussed examples of potential innovation projects we could deliver and asked what level of innovation funding offered best value and what types of innovation projects would customers like to see prioritised

A summary of customer insights on the proposed GNIS are provided in Figure 12.1.

We presented these findings to our stakeholder groups during a series of deep dive workshops on our Draft Plan. Some stakeholders were not supportive of a dedicated GNIS. These stakeholders questioned whether there are existing mechanisms in place that are potentially more appropriate to fund innovation expenditure for gas networks and whether the GNIS was inconsistent with our accelerated depreciation proposal.

Figure 12.2: Customer insights on GNIS

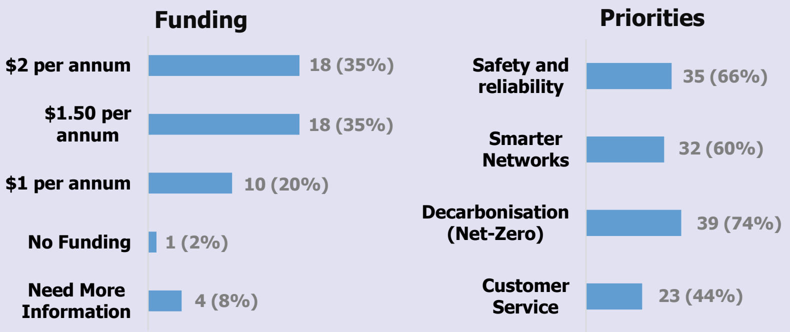
A majority of customers who participated in our workshops are supportive of innovation funding to trial new ideas and technology.

90% of customers support innovation funding.

- Protecting future generations: ***"I feel it is a worthwhile investment in my kids future..."***
- Ensuring exclusive use of funds for innovation: ***"So long as the money is locked exclusively into innovation, I'm happy for it to be reinvested back into innovation."***
- Some customers queried whether customers should ***"personally fund"*** innovation and whether the government can support.

Safety and reliability and Decarbonisation/Net zero are most prioritised by MGN customers, closely followed by Smarter Networks.

- "[I] would like to see more projects on R&D for 'greener' projects."



12.3 Current Period Performance

As noted above, our network is operating under the ECM and Contingent CESS in the current AA period. We are forecasting a total efficiency carryover of $1 million in the next AA period from the operation of these schemes (see Table 12.2).

Under the ECM, we forecast a benefit of $8 million related to efficiency gains made in the current period. This is in addition to the reward of $4 million applied to the six month extension period 1 January to 30 June 2023. As the opex ECM operates on a rolling basis, the payments from the scheme apply to both the six month extension period, and the next AA period. Our opex performance in the current period is discussed in more detail in Chapter 8.

Under the contingent CESS we forecast a penalty of $4.6 million. The penalty under the CESS reflects that we will overspend our capex allowance in the current AA period by around $11 million (or 3%). 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 93.5. This reflects a decline in performance for average duration and frequency of service interruptions and meter 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.

Table 12.2: 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 ECM	5.2	0.2	1.3	1.3	0.0	8.0
Contingent CESS	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(4.6)
Total	**4.3**	**(0.7)**	**0.4**	**0.4**	**(0.9)**	**3.4**

12.4 Opex ECM

Our network is currently subject to an opex ECM, similar in operation to the opex efficiency benefit sharing scheme (EBSS) which applies under the National Electricity Rules, 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 ECM works

The ECM is a key element of our opex forecasting approach (see section 8.4)[34] 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 ECM operates in a symmetric manner, which means that we are rewarded if there is an incremental efficiency gain, and penalised if there is an incremental efficiency loss.

To ensure that we have an incentive to pursue efficiency gains evenly throughout the AA period, we 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 ECM (and efficiency gains achieved/losses incurred) in the current AA period is provided in Table 12.2 above and again the building block revenue calculation 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 ECM in place for the last two AA periods. Over the two periods, we have achieved around $16 million in ongoing efficiency improvements, the benefits of which have been (or will be in the next AA period) passed through to our customers. Based on a simple NPV of the efficiency improvement shared between our business and customers, we calculate the scheme, in its current form, has delivered $195 million in benefits to our customers since its introduction.

An opex ECM (or EBSS) is also in place on all other gas and electricity distribution and transmission networks regulated by the AER. In March 2022 Houston Kemp prepared a report for Energy Networks Australia on *Consumer benefits resulting from the AER's incentive schemes*, which calculated customer benefits in the order of $7 billion delivered through the operation of EBSS and ECM schemes applied to electricity and gas service providers in Australia since 2006.

12.4.3 Consideration of the AER's review of the opex incentive schemes

The AER's Discussion Paper notes the ECM and EBSS schemes play an important role in forecasting efficient operating expenditure and providing a continuous incentive to pursue efficiency gains. We have proposed the opex ECM continue to apply to our network in the next AA period with no modifications to its operation.

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.

[34] Our opex forecasting approach relies on actual incurred opex in the penultimate year of an AA period being efficient.

12.5.1 How the CESS works

In a similar manner to the ECM, 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.[35][36] 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 that will apply in the next AA period are shown in Table 12.3. The targets have been reset based on most recent actual performance (2017-2021). The calculation of these targets is provided at Attachment 12.1 to this Final Plan.

Table 12.3: Asset performance index measures, targets and weightings

Measure	Target	Weigh t
Unplanne d SAIFI	7.00	25.0%
Unplanne d SAIDI	2,821.48	25.0%
Mains leaks	0.06	31.2%
Service leaks	4.25	15.6%
Meter leaks	11.63	3.2%

[35] 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.
[36] These benefits and costs must be adjusted for any financing benefits or costs.

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.

12.5.4 Consideration of AER's review of the capex incentive schemes

The AER's Discussion Paper notes the CESS is intended to provide networks with financial incentives to pursue efficiency gains over time. The CESS has now applied to most electricity network service providers for one regulatory period and the AER has examined whether the outcomes are consistent with the objectives of the scheme and if the current design remains fit for purpose.

Overall, the AER has observed that since the introduction of the CESS networks have underspent their capital expenditure allowances. This has benefited customers through lower capital expenditure added to the RAB, which in turn will lead to relatively lower network charges over time.

However the AER notes there are challenges in identifying drivers of capital expenditure underspending, with some stakeholders questioning if the rewards earned relate to actual benefits being delivered to customers through efficiencies or whether the benchmarks or forecasting were set too conservatively.

The AER considers a greater customer-centric approach may improve forecasting and a more flexible approach to financial incentives may also contribute to reducing the regulatory costs and information asymmetry associated with over-forecasting and concerns about whether capital expenditure incentive outcomes are commensurate with genuine efficiency gains. We understand the AER sought feedback on whether, it may be appropriate to adjust the strength of financial incentives, and/or change the balance of rewards and penalties, for each network.

We agree with other networks that the scheme is appropriately designed and stakeholder feedback around potential over-forecasting would be better addressed through the review process (and consider the AER's *Better Resets Handbook* is likely to do this).

We also note that the outcome of the operation of the Contingent CESS in the current AA period results in a reduction to revenue for the next AA period. That is, we will incur a penalty for having spent over the current AA period's capex allowance (due to under forecasted unit rates for our mains replacement). Therefore, we have not proposed any modifications to the operation of the Contingent CESS for our network in the next AA period.

12.6 Gas Network Innovation Scheme (GNIS)

In our Draft Plan we proposed the introduction of a new GNIS with dedicated funding in the order of $5 – 7.5 million over the period to undertake innovation projects, subject to customer and stakeholder support.

The GNIS we proposed in our Draft Plan was co-designed with customers and stakeholders through a dedicated joint engagement process with other gas distributors over a 12 month period.

You can find more information on the GNIS engagement on our dedicated engagement website gasmatters.agig.com.au.

As discussed in section 12.2 above, there was strong support from customers for dedicated innovation funding through a GNIS in the order of $1-2 per customer per annum. However, some stakeholders were not supportive of a dedicated GNIS, questioning whether other mechanisms to promote innovation were sufficient or more appropriate and whether a GNIS was inconsistent with our accelerated depreciation proposals.

We have responded to stakeholder feedback by not proposing to include a GNIS with dedicated innovation funding for the next AA period in this Final Plan.

Despite this, we will continue to look for ways we can innovate and deliver benefits to our customers through existing mechanisms such as the Australian Hydrogen Centre, the Future Fuels Cooperative Research Centre and partnering with governments.

Our views on the merits of a dedicated GNIS remain unchanged. We consider 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.

Innovation schemes exist in electricity in Australia and, internationally, mature innovation schemes exist for gas network businesses in the UK, Ireland, France and California.

We will continue to consider the introduction of a GNIS in future reviews.

12.7 Customer service incentive scheme

We maintain our Draft Plan position not to propose 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 8.0 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 ECM and Contingent CESS to pursue ongoing efficiencies and to share the benefits of these with our customers.

We have decided not to propose the introduction of a GNIS at this time.

13 Demand Forecasts

Customers will continue to connect to the network, reflecting customer demand for natural gas in their homes and businesses.

IN THIS CHAPTER:

- **Our demand forecasts have been independently determined applying methodologies consistent with those approved previously by the AER, and reflect existing government policy in support of decarbonisation of energy supply.**
- **Overall demand for gas across all sectors is expected to fall.**

The demand for our services drives our operations and is used to determine our prices.

Our forecasts of natural gas demand and customer numbers are key inputs to our growth capex and opex forecasts. They are also used to determine our prices (reference tariffs), which are calculated by dividing our forecast revenue requirement by forecast demand.

Reflecting the differences in the nature of demand for our services, separate demand and customer connection forecasts have been developed by independent expert Core Energy 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 AA period, Core Energy forecasts the demand for natural gas for our:

- residential segment to fall by 2.3% per year in response to a range of external factors, such as existing State government policy, higher wholesale gas prices, improved appliance and dwelling efficiency, lower economic growth due to COVID impacts and lower new dwellings growth;
- commercial customers to fall by 0.9% per year, driven by static consumption per connection and a forecast fall in connections; and
- industrial customers to fall by 1.3% 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 1.5% 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.

The NGR requires us to forecast on a reasonable basis and produce the best forecast possible considering the circumstances. The circumstances in which this demand forecast has been developed are unprecedented for the natural gas industry.

The new Federal Government has a strong mandate to pass legislation in support of rapid decarbonisation across the economy. Importantly, the new Government has a far more ambitious emissions reduction target by 2030 of 43%[37], replacing the 26% – 28% target of the previous Government. The majority of these reductions must be achieved within the next AA period.

These more ambitious Federal targets need to be viewed in unison with the Victorian State Government target of 45 – 50% by 2030 which brings the State and Federal targets largely into alignment. The Victorian Government's Gas Substitution Roadmap (the Roadmap) is due for release this year and is expected to outline how these targets will be achieved.

In line with Core Energy's usual methodology, our demand forecast has been adjusted for existing Government policy and its influence on demand. Core Energy will factor in further policy changes as they are announced.

13.2 Regulating gas pipelines under uncertainty

The AER released its information paper 'Regulating gas pipelines under uncertainty'[38] in November 2021. The paper outlines the challenges facing the gas sector including the increasing uncertainty of 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.

We are aiming to meet the AER's expectations as outlined in its information paper both through Core Energy's demand forecast and through our work on the Future of Gas. The work we have undertaken as part of our examination of the Future of Gas recognises the rapid technological change underway in the energy sector in recognition of government policy and consumer sentiment which aims for a decarbonised future.

Given this uncertain external environment, four scenarios have been developed which revolve around two axes – the electrification of heat and the hydrogen economy. The scenarios are Electric Dreams, Dual Fuel, Muddling Through and Hydrogen Hero. These scenarios are described in detail in the Future of Gas Chapter 6 of this Final Plan.

The scenarios reflect the fact that the future of the energy industry is uncertain, particularly given the complex interplay of many powerful drivers such as government Policy, private sector investment, consumer sentiment, elasticities of demand and technological change.

[37] https://www.alp.org.au/policies/powering-australia

[38] https://www.aer.gov.au/system/files/AER%20Information%20Paper%20-20Regulating%20gas%20pipelines%20under%20uncertainty%20-%2015%20November%202021.pdf

Through these scenarios we are attempting to measure the risk of economic stranding of our networks by 2050. Our demand forecast should be considered against the backdrop of the Future of Gas work, which considers possible demand for the delivery of gas given the uncertainties facing the gas sector.

We have attempted to capture known short-term influences on gas demand over the next AA period in the demand forecast, whilst the Future of Gas work looks at both the short and longer term to 2050 by examining a range of possible scenarios. We consider that the Future of Gas work is complementary to our demand forecast, reflecting risks which may arise even in the next AA period.

13.3 Stakeholder engagement

At our joint VGNSR and RRG meetings and through our large user survey, we discussed the forecasting approach and the importance of understanding key drivers of future demand. Stakeholder feedback is summarised in Table 13.1.

Stakeholders indicated they understood our approach to

Table 13.1: Customer insights on demand

What we heard	Our response
• Stakeholders acknowledged the decarbonisation journey we need to take to satisfy both our customers' expectations and our vision to be environmentally responsible. • Stakeholders appreciated the complexities faced by AGN when forecasting demand in the current environment. • Some stakeholders queried whether our demand forecasts might be overly optimistic, particularly considering the 2022 GSOO, speculation around the Roadmap and anecdotal evidence of changing customer preferences. • Stakeholders noted that they were comfortable with the approach to forecasting demand, including taking account of decarbonisation policies which will affect future demand. • Stakeholders also queried whether consideration can be given to local government intentions, given that some councils have flagged a desire for new estates to pursue electrification.	We have considered this feedback and taken the view that our forecasts should only factor in existing (and known) policy i.e., the Victorian Energy Upgrades Program (VEU). There remains a lot of uncertainty at the time of this Final Plan, and we must use the best information available at this time. The Roadmap is expected to be released around the time of our Final Plan submission on 1 July 2022. When the Roadmap is released and the policy detail known, we will examine it and factor it into our revised proposal. Similarly, in relation to potential actions by Local Government, we consider it prudent to wait until any such policies are announced. At a federal level, considerable funding has been earmarked to upgrade the electricity grid to fast-track electrification, subsidise electric vehicles, invest in green metals (the production of which currently requires natural gas) and to support solar and battery projects. We have not factored Federal Government intentions or the Roadmap into the demand forecast but we will continue to monitor developments over the coming months and update our forecast as these policies are rolled out. We will continue to engage on demand during our post-lodgement engagement program.
Final Plan Outcome	
We have revised down our commercial forecasts in response to this feedback. We will continue to engage on our demand forecasts during post-lodgement activities, and review these numbers based on any new information (i.e., policy positions).	
Stakeholders are seeking further engagement on this topic as new information becomes available (i.e., policy).	

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.

Our stakeholders queried whether our demand forecasts might be overly optimistic, particularly considering the Australian Energy Market Operator's (AEMO) Gas Statement of Opportunities (GSOO) 2022, speculation around the Roadmap and anecdotal evidence of changing customer preferences.

Stakeholders also queried whether consideration can be given to local government intentions, given that some councils have flagged a desire for new estates to pursue electrification.

We have considered this feedback and taken the view that our forecasts should only factor in existing policy i.e. the Victorian Energy Upgrades Program (VEU). There remains a lot of uncertainty at the time of preparing our Final Plan, and we must use the best information available at this time. The Roadmap is expected to be released around the time of our Final Plan submission on 1 July 2022. When the Roadmap is released and the policy detail known, we will examine it and factor it into our revised proposal.

Similarly, in relation to potential actions by Local Government, we consider it prudent to wait until any such policies are announced. At a federal level, considerable funding has been earmarked to upgrade the electricity grid to fast-track electrification, subsidise electric vehicles, invest in green metals (the production of which currently requires natural gas) and to support solar and battery projects.

We have not factored Federal Government intentions or the Roadmap into the demand forecast but we will continue to monitor developments over the coming months and update our forecast as these policies are rolled out.

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 13.1.

The methodology is consistent with the approach that was used to develop the demand forecasts

Figure 13.1: Forecasting method used for residential and commercial customers

Step 1 Normalise historic data	Step 2 Forecast demand per connection	Step 3 Forecast Connections	Step 4 Forecast Demand
1. Normalise the historic demand per connection data for both residential and commercial customers to remove fluctuations due to weather. 2. Use the normalised data to calculate an historic annual average growth in demand per connection. 3. Adjust for the effect of energy price changes from the historic growth.	Determine the forecast demand per connection by adjusting the normalised data in Step 1 to account for drivers that are not reflected in the historic data, e.g. the effects of Government policy or future energy price movements.	Derive a forecast of the net connections that will occur in the next AA period for residential customers (largely based on forecast new dwelling growth) and commercial customers (largely based on forecast economic activity).	Determine the forecast demand for both residential and commercial customers by multiplying the forecast consumption per connection from Step 2 by the total forecast connections for each customer group from Step 3.

for the current AA period our South Australia and AGN 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.

An adjustment for weather must therefore be made to historic residential and commercial demand to ensure the starting point and historic trends used to forecast gas demand are not unduly affected by abnormal weather conditions (see Step 1.1 in Figure 13.1.

The adjustment Core Energy has made is based on the same approach that is used by AEMO, which is referred to as the Effective Degree Day (EDD312) weather standard. This approach enables us to determine the volume impact attributable to annual variances to weather relative to the EDD baseline.

This volume impact is then removed from the historic consumption per connection trend to derive a weather normalised trend that can be used for forecasting purposes.

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).

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').

Core Energy's initial view was that it was not appropriate to apply elasticities to its forecast. Core Energy has now formed the view that despite these unusual influences on gas and electricity prices a reasonable elasticity can be derived.

Whilst the elasticities Core Energy has applied are the same as those used in our last South Australian AA, they are applied against an adjusted baseline because of the impact of COVID on consumer behaviour and hence consumption. Additionally, LNG netback prices in the east coast gas market prices have recently spiked to above $40 per GJ. These higher prices in turn affect the retail price of gas due to the wholesale component being higher than in the past and also electricity prices given there is significant gas generation built into the electricity price.

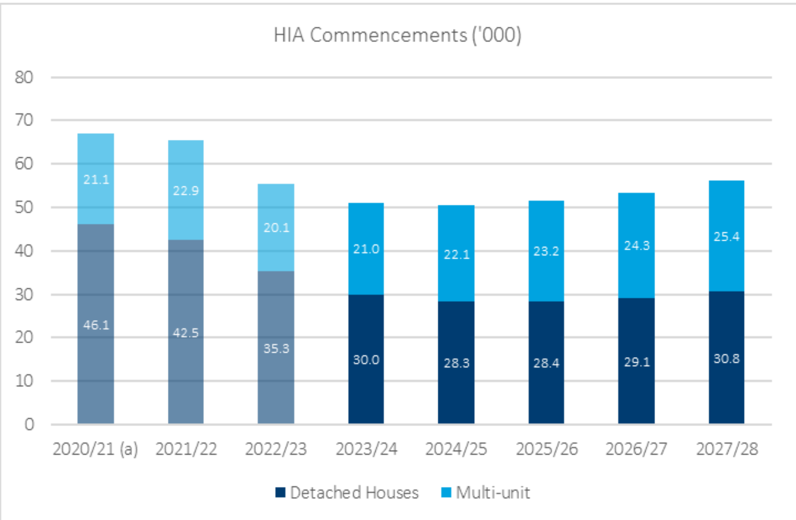
Taking these factors into account, Core Energy has adjusted baseline demand as follows:

- the historical trend has been adjusted for historical movements in gas and electricity prices;
- historical demand for 2022-23 onward has been derived based on pre-Covid levels demand;
- forecast demand for 2023-24 onward addresses estimated movements in future gas and electricity prices, including the impact of oil/LNG linked gas prices on both gas and electricity; and
- impact of current Government policy has been factored in.

Core Energy has derived elasticities as follows:

- Own-price elasticity: a lagged long-term-own-price elasticity estimate of -0.30 for residential and -0.35 for commercial customers has been assumed. This implies that a 1% increase in retail gas prices will result in a 0.3% and 0.35% reduction in consumption per connection for residential and commercial customers, respectively.
- Cross-price elasticity: a long-term-cross-price elasticity of -0.10% has been assumed for both residential and commercial demand (this implies that a 1% increase in retail electricity prices will result in a 0.10% increase in gas consumption per connection).

Figure 13.2: HIA Forecast of new dwelling commencements



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 Multinet network area.

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)[39].

As Figure 13.2 shows, the 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 51,000 dwellings in 2023/24 to 56,000 dwellings in 2027/28.

[39] HIA's February forecast has been used. We will update for the latest available forecast in the Revised Proposal.

Multi-unit dwellings are the key driver of this increase with 4,300 additional multi-unit dwellings over the AA period, whilst detached dwellings are forecast to be relatively stable.

Based on information available to date, we have not forecast a decline in the rate of new gas connections on account of customers choosing an all electric new build, which we accept may be optimistic in the current environment. We will however continue to monitor policy, planning and market developments with a view to incorporating any changes in the updated demand forecast to provided to the AER in response to the Draft Decision.

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 physically at home rather than their workplaces (and were unable to leave their homes for long periods).

Residential gas demand in 2019/20, which financial year captured the first few months of lockdown, was 10% higher than in 2018/19 and 2% higher after weather normalisation. Demand was also driven higher by the colder weather.

Conversely, gas demand in the commercial segment was negatively impacted due to restrictions on businesses trading during lockdown. This drove Commercial demand 11.0% lower in 2020/21 than the previous year.

Due to the volatility and asymmetrical impacts driven by COVID-19, Core Energy has adjusted the forecast by excluding demand data since the beginning of 2019/20 from the consumption trend.

Government Policy

The newly elected Federal Government is pushing to accelerate decarbonisation of the energy sector by targeting a 43% reduction in emissions relative to 2005 levels by 2030, which is a more ambitious target than the previous Government's 26% - 28% by 2030. This brings Federal Government policy largely into alignment with Victoria's committed emission reductions of 45% - 50% by 2030.

The measures the Federal Government are considering[40] to achieve this target favour electrification, including:

- Upgrading the electricity grid to fast-track electrification;
- Subsidising electric vehicles;
- Investment in green metals (steel, alumina and aluminium);
- Roll out of 85 solar banks around Australia to enable community ownership of solar programs; and
- Installation of 400 community batteries across Australia.

These measures accelerate the decarbonisation transition and will affect gas demand. For instance, the significant Federal Government expenditure on the electricity grid will assist in keeping electricity prices low, which will incentivise electrification to the detriment of gas demand.

We are still awaiting the Victorian Government's Roadmap and Federal Government policies which will also affect gas demand over the next AA period.

Despite these very significant policies on the horizon, Core Energy has currently only factored in the Victorian Government's VEU program as it is already funded and operating. We do not consider it prudent to attempt to quantify the impact of future policies on demand as this would be only a subjective adjustment. Once we have more certainty on the exact policy measures the State and Federal Governments are taking, Core Energy will factor them into our Revised Proposal demand forecast.

Given the uncertainty around the future of gas, and the general move towards electrification, we accept that our forecasts may be considered optimistic.

AEMO Gas Statement of Opportunities

AEMO produces its GSOO every year, which contains a number of modelled scenarios which reflect a range of possible future outcomes as a result of the rapid transformation occurring in the energy sector. AEMO's Slow Change scenario assumes challenging economic conditions following the COVID-19 pandemic with greater risk of industrial load closures, slower decarbonisation action and consumer's proactively managing energy costs. AEMO's Progressive Change scenario assumes a slower transformation of the energy sector with gas consumption close to historical levels, whilst its Step Change scenario assumes rapid change with significant reductions in gas

40 https://www.alp.org.au/policies/powering-australia

demand and significant electrification.

As shown in Figure 13.3, our forecast assumes AA growth of -1.3% (for Tariff V), which growth is closest to AEMO's Progressive Change scenario AA growth of -0.5%. As noted above, we have not taken into account any future policy. Once there is clarity both around Federal Government policy and the Roadmap our forecasts may be adjusted to reflect the significant electrification that may result and the consequent reduction in gas demand and this may be closer to AEMO's Step Change scenario

Zero Consuming Meters

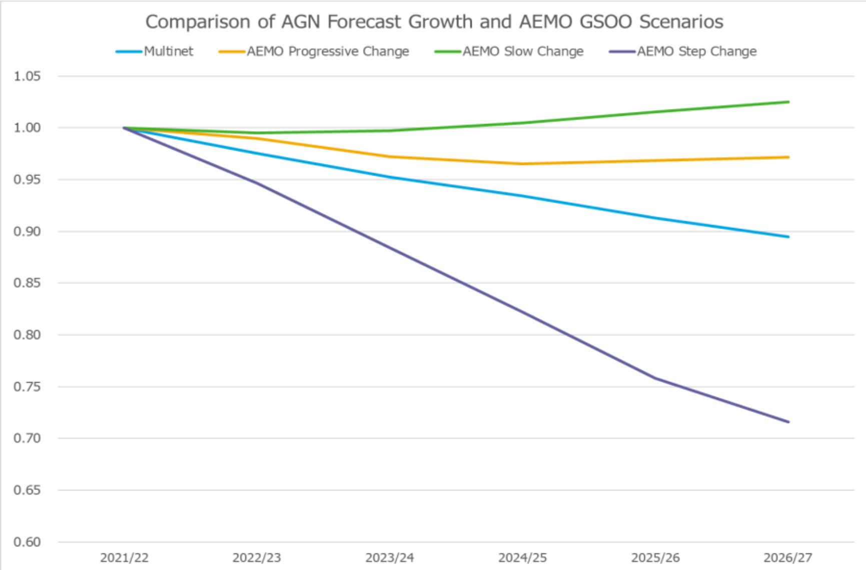
There are meters on our network for which there is no associated consumption. This situation may occur if a property is vacant or if supply has been cut off as a result of non-payment.

As at 30 June 2021, there were approximately 10,100 residential and 1,700 commercial zero consuming meters on the network which qualify for removal.

Reflecting past practice, Core Energy has assumed that all zero consuming meters are removed from the network over a 24 month period beginning in 2022/23. This assumption impacts:

- total connection forecasts, incorporated as a post-model adjustment to existing connections; and
- consumption per connection forecasts, as total consumption remains constant, but the number of connections reduces thereby resulting in an increase in consumption per existing connection.

Figure 13.3: GSOO Comparison



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 0.3% per year in the next AA period, reaching 709,279 by the end of the period (see Figure 13.3). The forecast growth in residential connections is slightly lower than the 10-year[41] historic average growth rate of 0.7% per year.

The forecast of new connections is driven by HIA's February 2022 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.

Core Energy has maintained its connection forecasting methodology which is to use the statistical relationship between our annual net connection growth with HIA dwelling commencement data (lagged by one year to reflect an average construction period).

Some stakeholders have queried why it is prudent to continue to connect new customers in the context of the decarbonisation of

[41] FY10 – FY19

Figure 13.4: Residential connections forecast

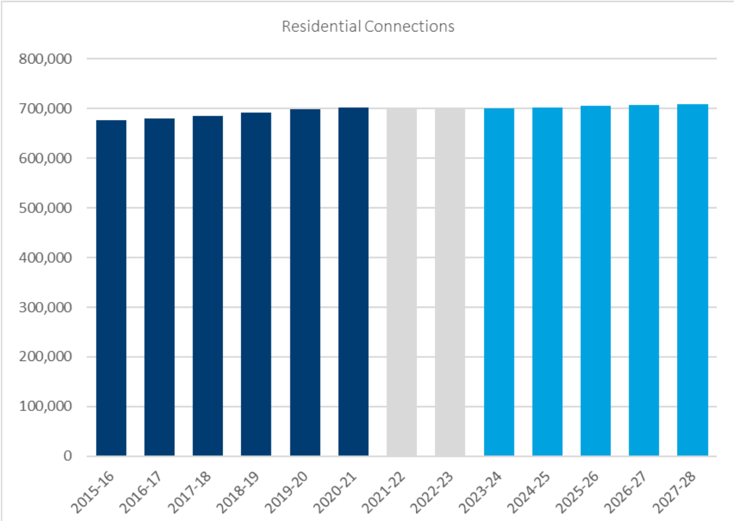


Figure 13.5: Residential Consumption per Connection

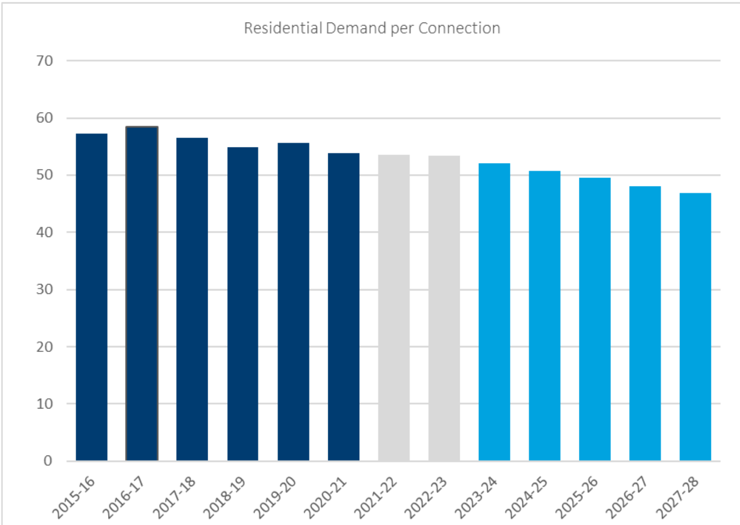
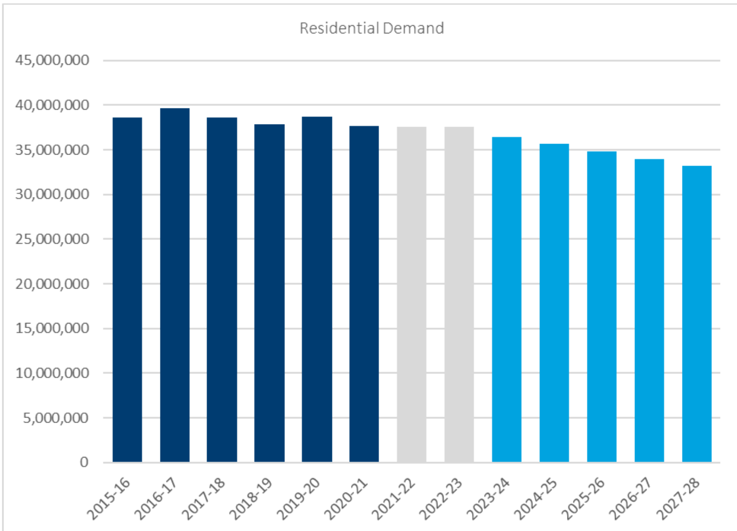


Figure 13.6: Total Demand



the energy sector. 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 price and is also important to enable an effective transition to renewable gas. Further, the forecasts are based on the current policy and market environment. We will continue to monitor for any changes, particularly in respect of Federal Government policy and the Victorian Government's Gas Substitution Roadmap.

Consumption per connection

Core Energy is also projecting that consumption per residential connection will fall by around 2.6% per annum over the next AA period, from 52.0 GJ in 2023/24 to 46.9 GJ in 2027/28.

The key drivers of this decline include improved appliance and dwelling efficiency driven by both technological improvement and 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).

Significant funding of around $1.6 billion has already been committed as part of the Victorian Government's VEU program to accelerate the transition to clean energy, including to:

- improve the energy efficiency of 250,000 low income homes;
- improve thermal performance and replace inefficient appliances;
- fund battery subsidies; and
- provide grants to large industrial energy users to introduce energy efficiency and demand management.

Core has factored the replacement of existing heaters with new electric heating systems into the forecast, thus reducing the demand for gas space heating. Our Multinet network has been allocated 69,000 of these replacements over the next AA period with adjustments made to consumption per connection as a result.

The trend in consumption per connection has also 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 affected gas demand in 2019/20 and 2020/21 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

The nearer term objectives of the 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 a combination of initiatives to reduce gas consumption in Victoria by nine percent by 2025[42], 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 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 journey of natural gas and what it means for our networks in the Future of Gas section.

Overall, the demand for gas by our residential customers in the next AA period is expected to fall by 2.6% per year from 36,459TJ in 2023/24 to 33,189TJ in 2027/28 (see Figure 13.6 and Table 13.2).

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.

[42] https://www.victorianenergysaver.vic.gov.au/save-energy-and-money/victorian-energy-upgrades

Commercial connections

In the next AA period, Core Energy is projecting the number of commercial connections (net of disconnections) will fall by -0.2% per year, which is in line with the 10-year historic average decline of -0.2%.

Again, we believe there is significant risk that given the Federal and State policies which are yet to come fully into effect, connections growth going forward could be more subdued.

Consumption per connection

The average consumption per commercial connection is expected to remain flat over the next AA period reflecting the long-term pre-COVID trend (see Figure 13.6).

The lockdowns in Melbourne due to COVID-19 reduced consumption by 11% in the Commercial segment in 2020/21 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 be flat over the next AA period at 386 GJ from 2023/24 to 2027/28.

Total Commercial demand

The total demand for gas from commercial customers is expected to decline by -0.9% per year over the next AA period from 5,708TJ in 2023/24 to 5,502TJ in 2027/28 (see Figure 13.9 and Table 13.2).

Figure 13.7: Commercial connections forecast

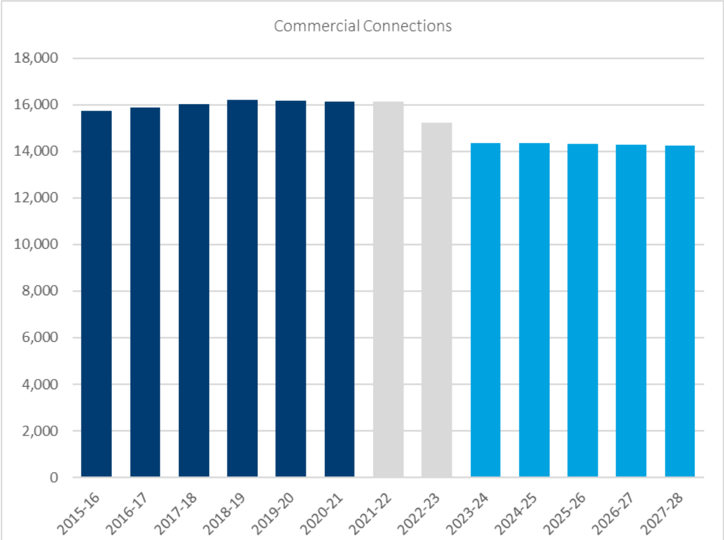


Figure 13.8: Commercial consumption per connection

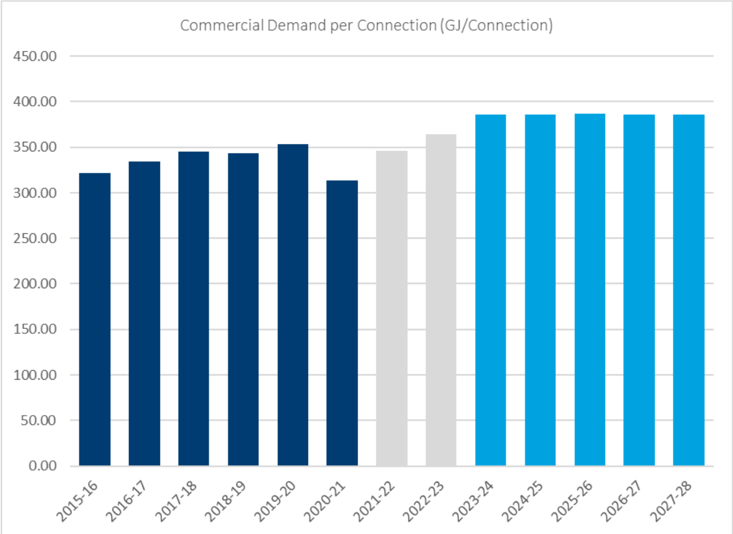
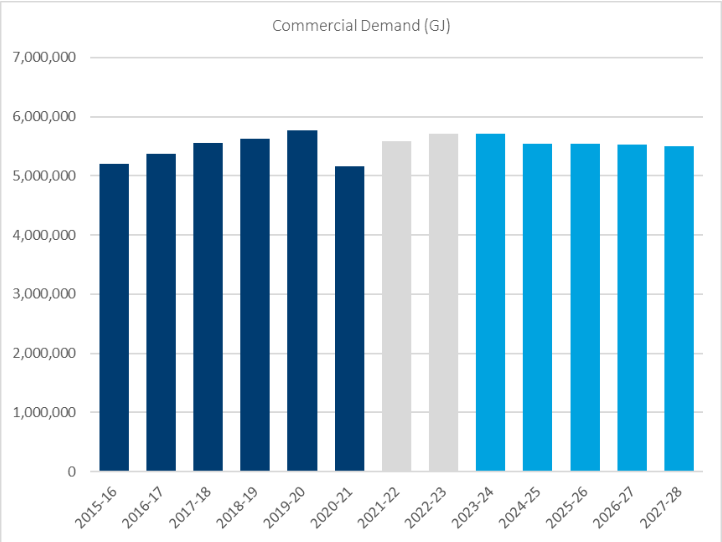


Figure 13.9: Total Demand



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.

Due to influences such as COVID-19, Core Energy was unable to determine statistically significant relationships between demand and economic activity or other specific drivers over recent years. Therefore, the MHQ and ACQ were forecast by applying an adjustment based primarily on the historic trend prior to 2018-19, being the final year not impacted by COVID-19.

The connections forecast for industrial customers was developed having regard to historic growth estimates and

Figure 13.10: Industrial MHQ

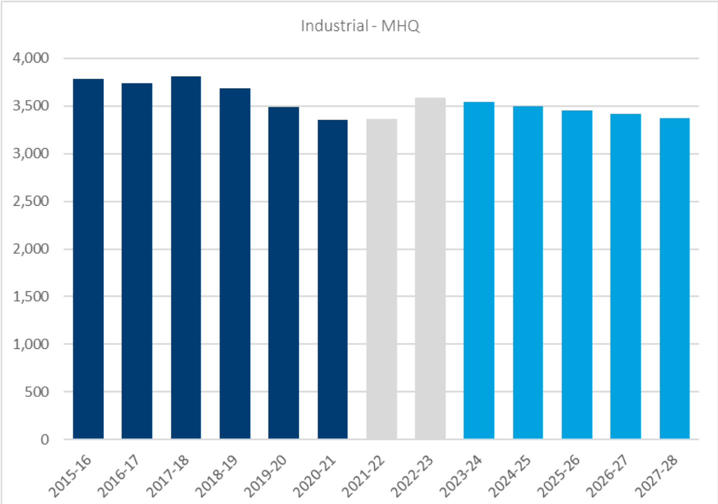
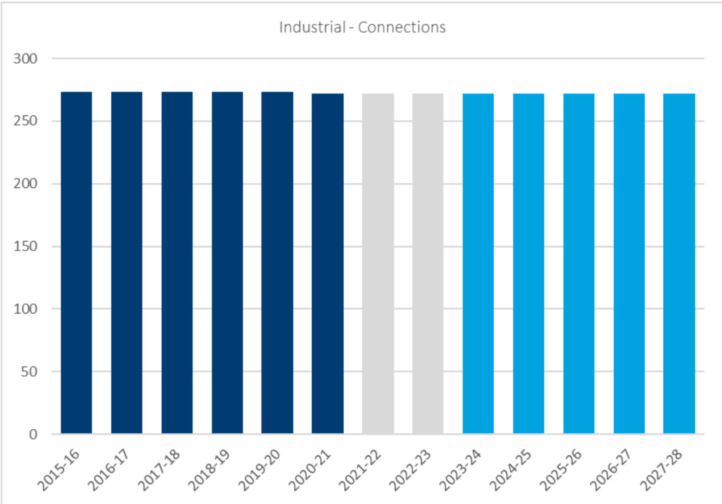


Figure 13.11: Industrial Connections



information on known new connections and disconnections

13.5.2 Industrial demand forecast

Industrial MHQ is forecast to decline by 1.3% per annum to 3,370 GJ MHQ over the next AA period (see Figure 13.10). Industrial connections are also forecast to remain constant at 273 connections (see Figure 13.11).

13.6 Summary

Table 13.2 provides a summary of our demand forecasts for the next AA period.

As this table shows, residential, commercial and industrial demand is forecast to decline over the next AA period.

Our demand forecasts are based on the methodology accepted by the AER in the current AA period for both our South Australian, Victorian and Albury networks, with adjustments reflecting the AER's expectations outlined in its information paper Regulating Gas Pipelines Under Uncertainty, including taking into account relevant climate change policies (as they are currently known) and elasticities of demand.

Due to timing issues, our forecasts do not reflect the impacts of future Federal Government policy or its objective to reduce emissions by 43% by 2030. Our forecasts also do not reflect the potential impact of the Victorian Government's Roadmap which is scheduled for release around the time of the release of this Final Plan, and will reflect its objective to release emissions by 45% - 50% by 2030. We will update the demand forecast to factor in the impacts of all known policies in our Revised Final Plan.

AEMO produces its GSOO every year which contains a number of modelled scenarios which reflect a range of possible future outcomes as a result of the rapid transformation occurring in the energy sector. AEMO's Progressive Change scenario assumes a slower transformation of the energy sector with gas consumption close to historical levels whist its Step Change scenario assumes rapid change with significant reductions in gas demand and significant electrification.

Our forecasts are closer to AEMO's Progressive Change scenario because we have not taken into account any future policy. Once there is clarity both around Federal Government policy and the Roadmap our forecasts may be adjusted to reflect those policies.

Table 13.1: Summary of demand forecast

	2023/24	2024/25	2025/26	2026/27	2027/28
Residential demand					
Connections (no.)	700,216	702,698	704,882	707,085	709,279
Consumption per connection (GJ)	52.0	50.8	49.5	48.1	46.9
Demand (TJ)	**36,460**	**35,625**	**34,845**	**33,952**	**33,189**
Commercial demand					
Connections (no.)	14,367	14,337	14,307	14,277	14,247
Consumption per connection (GJ)	385.6	386.3	386.9	386.3	385.8
Demand (TJ)	**5,708**	**5,544**	**5,541**	**5,521**	**5,502**
Industrial Demand					
Connections (no.)	272	272	272	272	272
MHQ (GJ)	**3,545**	**3,501**	**3,457**	**3,413**	**3,370**

14 Revenue and Pricing

This section sets out the total revenue and the proposed prices to apply over the next AA period.

IN THIS CHAPTER:

- **We have proposed to cut Multinet network prices by 1% on 1 July 2023.**
- **Our Final Plan price path is for an upfront price cut with no price changes thereafter, however we will also present an alternative price path which will deliver more stable prices through time.**

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. Our prices are also required to lie between the avoidable and stand-alone cost of providing services, take into account transaction costs and provide efficient price signals.

14.2 Stakeholder engagement

Customers and stakeholders told us that affordability is their highest priority. In developing this Final Plan we have had regard for the impact individual aspects of the plan will have on the affordability of natural gas. Our proposal is for a price cut to distribution charges and accordingly we believe we have responded to this feedback.

Stakeholders have also queried the existing declining block tariff structure, which structure reflects the low marginal cost of increasing the supply of gas to customers and is designed to encourage greater network utilisation.

The NGR requires us to design tariffs in a way that takes the long-run marginal cost for reference services into account, a requirement that is reflected in the current declining block structure.

Our tariffs are designed so that a customer's bill does not rise dramatically during peak periods such as winter when space heating in Victoria drives high consumption. We believe that customers are able to respond to price signals because retailers largely reflect our distribution tariffs in their retail tariffs.

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	71.4	76.6	83.4	88.7	94.2
Return of Capital	53.8	48.7	49.2	52.6	53.8
Opex	85.2	87.2	89.7	91.7	95.9
Revenue Adjustments	2.7	-2.7	-1.6	-1.8	-3.4
Cost of Tax	8.4	4.5	2.0	2.7	2.4
Building Block Total Revenue (including ARS)	**221.5**	**214.4**	**222.8**	**233.9**	242.9
Less ARS	2.6	2.7	2.8	2.9	3.0
Building Block Total Revenue (excluding ARS)	**218.9**	**211.7**	**219.9**	**231.0**	**239.8**

Note: Totals may not add due to rounding

Table 14.2: Summary of customer and stakeholder feedback

What we heard	Our response
• Customers and stakeholders told us that affordability is their highest priority. • Customers told us affordability means fair and transparent prices, manageable risk and forward visibility to avoid 'bill shock' • Gas is a significant cost for many major users (commercial and industrial customers) and they stressed the importance of keeping costs low. • Stakeholders have also queried the existing declining block tariff structure, which structure reflects the low marginal cost of increasing the supply of gas to customers and is designed to encourage greater network utilisation. • Stakeholders have also raised whether encouraging utilisation of our network is appropriate given the current decarbonisation of the energy sector. As a regulated business, we have regard to the NGR when designing our tariffs. In its current form, the NGR encourages us to design tariffs in such a way that network utlisation is maximised such that the cost of our service to each customer is minimised to the greatest extent possible.	In developing this Final Plan we have had regard for the impact individual aspects of the plan will have on the affordability of natural gas. Our proposal is for a price cut to distribution charges and accordingly we believe we have responded to this feedback. Our tariffs are designed so that a customer's bill does not rise dramatically during peak periods such as winter when space heating in Victoria and Albury drives high consumption. We believe that customers are able to respond to price signals because retailers largely reflect our distribution tariffs in their retail tariffs. The removal of seasonal pricing was tested with customers directly through our customer workshops, with around 80% of participants supporting the change. We therefore see an opportunity to simplify our tariff structures, lowering these transactional costs, sending clearer price signals to customers and providing more transparency for all stakeholders in the long-term. In this Final Plan we propose to remove the seasonality in our prices.

Final Plan Outcome
Our Final Plan focuses on affordability and keeping prices low for customers. We are proposing simplification of our tariffs to minimise transaction costs and sending clearer price signals.
Customers were pleased to see that prices for the gas distribution component of their bill would not be increasing.
Stakeholders were encouraged to see that AGN was not proposing price increases for customers.

to consume according to their needs and respond to cold weather. A flat tariff structure reduces the affordability of our services during peak periods, meaning heating needs may not be met and demand could be curtailed. Customers can respond to our tariffs because they are reflected in the retail price and understand that in the event of an unusually cold winter, they can increase consumption without commensurate increases in winter bills.

Stakeholders have also queried whether encouraging greater utilisation of our network is appropriate given the current decarbonisation of the energy sector. As a regulated business, we have regard to the NGR when designing our tariffs. The NGR encourages us to design tariffs in such a way that network utlisation is maximised such that the cost of our service to each customer is minimised to the greatest extent possible.

There is further discussion in relation to our declining block structure in Section 14.4.10.

14.3 Building Block Total Revenue

This Final Plan outlines the basis of all the relevant building blocks that are used to determine building block total revenue. We recover our costs through the prices (or tariffs) that we charge retailers for providing Ancillary Reference Services (ARS) and Haulage Reference Services (HRS).

The building block total revenue with and without the cost of providing 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 ARS. We are required to set our prices such that the total revenue we recover equals the building block total revenue.

ARS are those services that are specifically requested to be provided by users. The forecast volume of ARS to be provided over the next AA period is explained in our Operating Expenditure chapter. Table 14.3 sets out the ARS building block total revenue, which is determined by multiplying the forecast volume by the price of providing ARS in each year.

Our Final Plan has set out the derivation of all the building blocks that are used to determine the building block total revenue, aside from the return on capital building block. This is determined by multiplying the rate of return (or weighted average cost of capital) by the opening regulatory asset base (RAB) in each year of the next AA period.

Table 14.3: Proposed Price Path and Revenue, 2023/24 to 2027/28 ($nominal, million)

	2023/24	2024/25	2025/26	2026/27	2027/28
Building Block Total Revenue (excluding ARS)	218.9	211.7	219.9	231.0	239.8
Smoothed Revenue	218.0	220.7	224.0	226.9	230.3
Final Plan - Real Price Path	3.46%	0.00%	0.00%	0.00%	0.00%
Building Block Total Revenue (excluding ARS)	218.9	211.7	219.9	231.0	239.8
Smoothed Revenue	207.7	215.5	224.3	232.8	242.3
Alternative Price Path	8.00%	-2.50%	-2.50%	-2.50%	-2.50%

The building block total revenue, smoothed revenue and percentage changes in prices are set out in Table 14.3. The price cut in the first year of the AA period followed by no price changes thereafter reflects our engagement with 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 stakeholders to understand and compare.

As we have done in previous reviews, for the purposes of the Final Plan, we have developed a price path that delivers stable prices through across AA periods. In particular, the price path:

- 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.

We have also provided an alternative price path in Table 14.3 for consideration. This price path balances the above two objectives by increasing the upfront price cut and balancing this with subsequent real price rises. This more closely aligns the building block and smoothed (tariff) revenue in the final year of the next AA period. This will minimise any adjustment that will be required due to building block and tariff revenue being misaligned in the next price reset on 1 July 2028.

Also, by aligning our price path to the growth in our capital base we are more likely to sustain stable credit metrics at levels assumed

Table 14.4: Forecast Revenue from Ancillary Reference Services, 2023/24 to 2027/28 ($m)

$ million (nominal)	2023/24	2024/25	2025/26	2026/27	2027/28
Turn On / Reconnections	0.29	0.30	0.31	0.32	0.33
Meter Investigations	0.03	0.03	0.03	0.03	0.03
Disconnections	0.30	0.31	0.32	0.33	0.34
Special meter reading	1.72	1.78	1.84	1.90	1.96
Meter Removals	0.29	0.30	0.31	0.32	0.33

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).

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). However, we note that given current economic conditions, interest rates will more likely rise in the coming years which will mean this metric is likely to deteriorate over time as our financing costs rise.

We have assessed the key credit ratios delivered by our Final Plan (see Table 14.5). Our Final Plan delivers an average FFO to debt of 9.0% and FFO to interest of 3.2 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.

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 Regulatory Framework

Our prices are required to reflect the underlying cost of providing services to our customers. Our prices are also required to lie between the stand-alone and avoidable costs of providing services, take into account transaction costs and provide efficient price signals.

14.4.2 Current Pricing Structure

Our current pricing structure includes three tariff zones:

- Multinet Metro;
- Yarra Valley; and
- South Gippsland.

Both our residential and commercial tariffs comprise these three zones.

Table 14.5: Final Plan Key Credit Ratios, 2023/24 to 2027/28

	2023/24	2024/25	2025/26	2026/27	2027/28	Average
FFO to Debt	9.1%	10.0%	9.4%	8.5%	8.0%	9.0%
FFO to Interest Cover	3.3	3.4	3.3	3.1	2.9	3.2

Table 14.6: Charging Parameters by Customer Type

Residential (Tariff V)	Non-Residential (Tariff V)	Non-Residential (Tariff D)
Fixed Charge	Fixed Charge	0 – 50 GJ MHQ
0 - 18.25 GJ	0 - 91.25 GJ	>50 GJ MHQ
18.25 - 36.50 GJ	91.25 - 365.00 GJ	
36.5 - 54.75 GJ	365.00 - 547.50	
54.75 - 91.25 GJ	547.50 - 1825.00 GJ	
> 91.25 GJ	> 1825.00	

Our industrial tariff comprises two zones:

- Multinet Metro; and
- South Gippsland.

Prices for residential and commercial customers consist of five 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 tariffs, whilst the commercial pricing structure is made up of a fixed charge and four volumetric tariffs.

We currently recover approximately 79% of our revenue in the residential and commercial segments in the variable (volumetric) components of our tariffs and 21% 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 14.6). All prices decline as usage increases to promote better network utilisation.

Multinet also has a seasonal tariff structure which varies tariffs across the five volumetric blocks throughout the year. The Peak period which covers the coldest time of year and hence the highest gas consumption period of June to September, Off-Peak which covers the warmer months and hence lowest consumption period of November to April and shoulder periods May and October.

We consider this structure overly complex, with fifteen different volumetric charging parameters applying in each of the Residential and Commercial segments, in addition to the fixed charge. The peak period prices are the highest when demand for gas is at its greatest for space heating, and therefore the least discretionary for customers.

We also consider the complex structures drive higher transaction costs for retailers (i.e. the costs of maintaining the tariff structures and indeed billing according to the tariff structures). These transaction costs are then passed on to consumers, with more complex structures generating more cost.

The removal of seasonal pricing was tested with customers directly through our customer workshops, with around 80% of participants supporting the change. We therefore see an opportunity to simplify our tariff structures, lowering these transactional costs, sending clearer price signals to customers and providing more transparency for all stakeholders in the long-term. In this Final Plan we propose to remove the seasonality in our prices.

14.4.3 Tariff V

Tariff V applies to customers using less than 10,000 GJ a year and less than 10 GJ MHQ. Within Tariff V there are two classifications: Residential and Non-Residential. Any new customer eligible for Tariff V is assigned their appropriate residential or non-residential classification by their retailer.

Tariff V contains a fixed and variable charge. The fixed charge recovers unavoidable network infrastructure costs such as service connection, standard meters, and systems for billing and collection. The variable peak, shoulder and off-peak charges recover all other costs associated with the Distribution use of System.

Tariff V customers are charged a fixed daily charge and a price per GJ which decreases with increased usage. There are currently five usage blocks for Residential and Non-Residential Customers as shown Table 14.6.

14.4.4 Tariff D

Tariff D applies to customers using greater than 10,000 GJ a year or more than 10 GJ MHQ. Customers are charged based on their Maximum Hourly Quantity (MHQ) measured in gigajoules (GJ) per hour. The MHQ unit rates are stepped as follows:

- 0-50MHQ (GJ/Hr)
- >50MQH (GJ/Hr).

Distribution Demand Charge = (Estimated Annual Charge – Charges to Date) / Remaining Bill Periods, where the Estimated Annual Charge is:

For billing periods between January and September, if Actual Annual MHQ>Forecast Annual MHQ then:

- Estimate Annual Charge = Actual Annual MHQ * Rate
- Estimate Annual Charge = Forecast Annual MHQ * Rate

For billing periods between October and December, if the Maximum Annual MHQ for the last 9 months is less than the Forecast Annual MHQ then:

- Forecast Annual MHQ = Maximum Annual MHQ * Rate; or
- Estimated Annual Charge = Forecast Annual MHQ * Rate

14.4.5 Tariff L

Tariff L is open to customers who consume more than 1TJ per annum or less than 10TJ per annum and have an MHQ demand of less than 10 GJ per hour.

The tariff structure of Tariff L is a hybrid of the Tariff V and D tariff structures. Tariff L has no fixed charge, however it contains seasonal stepped usage charges and two demand charges. There are currently two usage blocks for Tariff L customers.

Tariff L was initially designed for larger non-residential tariff V customers (small industrial) that could manage their load and reduce peak usage. We have not marketed the tariff and utilisation of Tariff L has been extremely low. There are currently only 11 Tariff L customers despite the tariff being in place for around a decade

We will liaise with retailers with a view to ceasing to offer Tariff L to new customers in the next AA period.

14.4.6 Allocation of Total Revenue

We provide both Haulage Reference Services (HRS) and Ancillary Reference Services (ARS). ARS relates to specific services requested by a retailer, such as to undertake an additional (or special) meter read or to remove a meter from a customer site. Prices are charged to the retailer that requested the ARS.

The HRS accounts for the majority (98%) of our revenue/costs. The two HRS we are proposing to provide include:

- Volume Haulage Service – this service provides for the delivery of gas to those customers using less than 10 terajoules (TJ) of gas per annum and includes the reading of meters every two months. There is a separate price for residential customers and commercial customers (see Table 14.6);
- Demand Haulage Service – this service provides for the delivery of gas to those customers using more than 10 TJ per annum and includes reading the meter every month (see Table 14.6).

We have developed a cost allocation model (CAM) to allocate costs to the above HRS (see Attachment 14.2). The CAM allocates the HRS building block revenue to each pricing category on the basis of a number of different cost allocators, which allocates based on customer numbers and consumption. The allocators selected reflect the best estimate of the cost of servicing each HRS.

As explained in Attachment 14.1, the revenue we recover from each tariff class lies on or between an upper bound (representing the stand alone cost of providing the reference service to the customers who belong to that tariff class) and a lower bound (representing the avoidable costs of not providing the reference costs to those customers).

Table 14.7: Multinet Tariff Zones and Tariff Classes

Tariff Classes	Residential V	Non-Residential V	Tariff L	Industrial (Tariff D)
Tariff Zones	Metro	Metro	Metro	Metro
	Yarra Valley	Yarra Valley		South Gippsland
	South Gippsland	South Gippsland		

As expected, there has been no material change in cost allocation between the HRS for the next AA period. Rather, we have updated the previous approach to cost allocation that was approved by the AER for the current AA period for current cost (or building block) information provided throughout this Final Plan.

We have utilised the same approach to allocating costs to HRS for the next AA period as already approved by the AER for the current AA period for our Victoria & Albury network.

14.4.7 Cost differences between zones

We have three zones for the purposes of pricing:

- Metropolitan
- Yarra Valley
- South Gippsland.

Both Yarra Valley and South Gippsland are relatively new networks and have been connected with the assistance of funding from Regional Development Victoria (RDV). Despite this assistance, both of these networks require additional revenue to recover the projected shortfall of revenue to costs and this is reflected in pricing.

14.4.8 Proposed Prices for Haulage Reference Services

We are proposing to simplify Multinet's seasonal tariff structure in the next AA period.

The current structure changes throughout the peak, off-peak and shoulder periods, which varies tariffs across the five volumetric blocks throughout the year.

The three periods are:

- the Peak period which covers the coldest time of year and hence the highest gas consumption period of June to September;
- Off-Peak which covers the warmer months and hence lowest consumption period of November to April; and
- The two shoulder periods in May and October.

We consider this structure overly complex, with fifteen different volumetric charging parameters applying in each of the Residential and Commercial segments, in addition to the fixed charge. The peak period prices are the highest when demand for gas is at its greatest for space heating, and therefore the least discretionary for customers.

We also consider the complex structures drive higher transaction costs for retailers (i.e. the costs of maintaining the tariff structures and indeed billing according to the tariff structures). These transaction costs are then passed on to consumers, with more complex structures generating more cost.

The removal of seasonal pricing was tested with customers directly through our customer workshops, with around 80% of participants supporting the change. We therefore see an opportunity to simplify our tariff structures, lowering these transactional costs, sending clearer price signals to customers and providing more transparency for all stakeholders in the long-term.

In this Final Plan we propose to remove the seasonality in our prices.

14.4.9 Pricing Structures

This section discusses the proposed price structures set out in Table 14.6. In short, we are not proposing any change to our existing price structures.

14.4.10 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, which is part of the package of measures that we use to address the observed long-term decline in demand per connection.

This pricing approach incentivises efficient utilisation of our networks and helps us remain prices competitive with electricity.

On the Multinet network, the volumetric price bands account for around 78% and 81% of the average residential and commercial gas distribution revenue respectively. We believe that the level of cost recovery from the variable bands is consistent with feedback from past customer workshops, where the majority of participants supported a high to very high degree of variability in their gas bill in line with their gas usage.

Our first residential pricing band broadly captures a customer using a gas cooker and 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. band

We consider our pricing structures align with our obligations that require AGN to promote the efficient use of the network. We therefore consider there is strong merit in retaining the existing declining pricing structure and propose that it be retained in the next AA period.

14.4.11 Haulage Reference Service Tariff Classes

We are required to allocate customers for the two HRS into tariff classes. Customers are assigned to a particular tariff class within a HRS on the basis of their geographic location. The list of tariff classes is shown in Table 14.7.

14.4.12 Residential Tariff V and Non Residential Tariff V

As described in section 14.4.2, Haulage Reference Tariffs Residential V and Non-Residential V both comprise five tariff categories based on geographic location.

The Tariff V Residential and Tariff V Non-Residential Reference Tariffs comprise the following charging parameters:

- supply charge (in dollars per day); and
- banded volume charges (in dollars per gigajoule per day).

The supply charge is a fixed daily charge that applies to all DPs and is designed to:

- reflect the predominantly fixed-cost nature of gas distribution; and
- signal each customer's connection costs, having regard for the size, location and type of network user.

Both Residential V and Non-Residential V Reference Tariffs consist of several volumetric (or consumption) based charging parameters (in dollars per gigajoule per day). Residential V will comprise the following three volumetric charging bands:

- a charge for the first 0.05 gigajoules of gas delivered (dollars per gigajoule) – equating to 18.25 gigajoules per annum;
- a charge for the next 0.05 gigajoules of gas delivered (dollars per gigajoule) – equating to the next 18.25 gigajoules per annum;
- a charge for the next 0.05 gigajoules of gas delivered (dollars per gigajoule) – equating to the next 18.25 gigajoules per annum;
- a charge for the next 0.10 gigajoules of gas delivered (dollars per gigajoule) – equating to the next 36.50 gigajoules per annum;
- a charge for additional gas delivered (dollars per gigajoule).

Non-Residential V will maintain the following four volumetric charging bands:

- a charge for the first 0.25 gigajoules of gas delivered (dollars per gigajoule) – equating to 91.25 gigajoules per annum;
- a charge for the next 0.75 gigajoules of gas delivered (dollars per gigajoule) – equating to the next 273.75 gigajoules per annum;
- a charge for the next 0.50 gigajoules of gas delivered (dollars per gigajoule) – equating to the next 182.5 gigajoules per annum;
- a charge for the next 3.50 gigajoules of gas delivered (dollars per gigajoule) – equating to the next 1,277.5 gigajoules per annum;
- a charge for additional gas delivered (dollars per gigajoule).

We are proposing to rename these tariffs to Tariff R and Tariff C in the next AA period.

14.4.13 Industrial Customers

The prices for our industrial customers are based on the maximum usage of that customer at any point in time measured typically over the past year (referred to as capacity based prices). Capacity based prices encourage industry customers to have a smooth (or flat) usage profile as opposed to a 'peaky' profile. A flatter usage profile will lower gas network costs and improve network utilisation as the size (or capacity) of the network does not have to accommodate short-term increases in usage.

Like residential and commercial customers, the industrial pricing band decreases as capacity increases, which is again designed to encourage greater network utilisation (thereby lowering average costs to all customers).

14.4.14 Customer Impact

As shown in Table 14.8, we are proposing an 3% real price cut (1% after inflation) on 1 July 2023 across all customers. We have also explained in this chapter that we are proposing to maintain the same allocation of costs and pricing structures to all customers. This therefore means that all customers will receive, on average, an 3% reduction in their distribution charge before inflation.

The average change in distribution charges on 1 July 2023 for each tariff zone is outlined in Table 14.8. The average annual change

Table 14.8: Average Change in the Annual Charge to Customers from 1 July 2023 ($nominal)

Average Customer Saving	2022/23 Average Annual Charge ($)	2023/24 Average Annual Charge ($)	Saving ($)	Saving (%)
Residential V				
Metro	413.1	411.0	-2.1	-0.5%
Yarra Valley	451.8	449.4	-2.3	-0.5%
South Gippsland	347.6	345.8	-1.8	-0.5%
Non-Residential V				
Metro	1,040.1	1,034.8	-5.4	-0.5%
Yarra Valley	2,151.0	2,139.9	-11.1	-0.5%
South Gippsland	4,065.2	4,044.2	-21.0	-0.5%
Tariff L				
Metro	2,305.2	2,293.3	-11.9	-0.5%
Tariff D				
Metro	32,482.6	32,315.1	-167.5	-0.5%
South Gippsland	35,097.2	34,916.3	-180.9	-0.5%

over the AA period for our residential, commercial and industrial gas distribution charges is $24, $60, and $1,864 respectively. Attachment 14.1 and our AA Document set out the proposed prices to apply from 1 July 2023.

14.5 Proposed Prices for Ancillary Reference Services

We propose to maintain the number, structure and level (in real terms) of the prices charges in respect of ARS (see Table 14.9).

14.5.1 Price Variation Mechanisms

We are allowed to vary our prices over the next AA period in accordance with procedures approved in our AA Document (referred to as approved price or tariff variation mechanisms). We are proposing the same price variation mechanisms in the next AA period to that applying in the

Table 14.9: Forecast tariffs for Ancillary Reference Services ($ nominal, excluding GST)

Ancillary Reference Service	Tariff
Turn On / Reconnections	$52.87
Meter Investigations	$179.03
Disconnections	$62.72
Special meter reading	$8.04
Meter Removals	$72.15

current AA period. In particular, we are proposing:

- to maintain the current annual price variation mechanism, including the form of price control;
- to maintain administrative processes for the approval of variations to prices;
- to maintain the same ability to adjust prices in response to certain defined (and unexpected) events (referred to as Cost-Pass-Through events).

These matters are discussed in the remainder of this chapter.

14.5.2 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.

This control places a constraint on the overall average movement in prices from one year to the next (referred to as a weighted average price cap, or WAPC). The constraint allows average prices to increase by the annual change in the Consumer Price Index (CPI) less the X-factor plus an adjustment factor (see Section 14.5.3).

This price cap form of price control is therefore applied to average prices rather than the total revenue that we can recover. This provides a stronger incentive on the business to increase customer connections and usage relative to a revenue cap. This is because our revenue will increase as the number of customers connected to our network and/or usage increases, whereas the revenue recovered under a revenue cap does not vary with increased usage.

We consider the incentive to increase usage under a price cap is consistent with the growth incentive that applies to a gas distribution network more generally. This reflects that gas is a fuel of choice for most applications (all applications in the case of residential customers). The price cap form of control therefore complements our:

- pricing structures discussed earlier in this chapter, particularly our declining price bands that are aimed at encouraging greater network usage/utilisation;
- plans to convert our networks to carry renewable gas; and
- marketing initiatives that are aimed at increasing customer connections and network usage (see the Operating Expenditure chapter).

Encouraging greater network usage lowers prices for existing customers. This is because prices are determined by dividing building block total revenue by total network usage. This means that, all other things remaining equal, prices will fall as usage increases.

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 continue to stimulate demand, but to a greater and greater extent, stimulate demand for renewable gas. Conversely, we do not consider a revenue cap appropriate given the resultant price volatility that would arise from year to year, and the disincentive it would provide to grow the network, which in turn would hamper the transition to renewable gases. We also do not believe the price volatility that may flow from over and under recovery of revenue under a revenue cap would not be in the best interest of customers.

A price cap is consistent with our plans to commence blending renewable gases into the gas network over the next decade, as it will continue to stimulate demand on the network as natural gas is gradually substituted with hydrogen and biogas. The best mechanism to achieve is the price-cap form of revenue control.

We therefore consider there is strong merit in retaining the existing declining pricing structure and form of revenue control.

The price control formula forms part of Annexure D of the AA Document and is described in more detail in Attachment 14.1.

14.5.3 Adjustment Factor

The adjustment factor is used in both the price control formula (as described in the previous section) and the rebalancing control formula (as described in the following section). This factor allows for any pass through amount approved by the AER to be recovered from or returned to our customers. We do not propose any changes to the existing adjustment factor.

14.5.4 Rebalancing Control Mechanism

The rebalancing control provides greater flexibility to adjust prices from one year to the next than allowed for by the price control on its own. The rebalancing control allows average prices for each of the 9 pricing categories set out in Table 14.7 to change by a fixed percentage above that allowed for by the price control.

We propose to maintain the current rebalancing control of 2% (before inflation).

The rebalancing control formula forms part of Annexure D of the AA Document and is explained in more detail in Attachment 14.1.

14.5.5 Price Variation Process

We are proposing a consistent approach to that applying in the current AA period to varying prices in respect of the annual price adjustments that are to be made over the next AA period. These annual price adjustments are required to account for the annual change in inflation and the applicable X-factor for each year and enables us to recover our allowed building block revenues.

We will continue to notify the AER in respect of any variations to our prices at least 60 business days before those prices are proposed to come into effect. The notification to the AER will continue to provide an explanation of how the proposed variations comply with the price control and rebalancing control. We will also continue to publish our prices, including our pricing proposals, on our website.

14.5.6 Cost-Pass-Through Events

We are allowed to adjust our prices during an AA period:

- to reflect changes in our costs that are not within our control; and/or
- where it is unreasonable to accurately determine the impact of costs; and/or
- where the occurrence of the event is uncertain.

We are only allowed to recover these costs where the cost is considered to be material, which is defined by the AER as an event that has an impact of 1.0% of forecast revenue in the year(s) the event occurs. Any Cost-Pass-Through event must first be approved by the AER before being passed through to customers.

The proposed Cost-Pass-Through Events align with those we have proposed for our AGN Victoria and Albury networks.

The proposed Cost-Pass-Through Events are set out below. We note that we may revise our proposal relating to Cost Pass Through Events and possibly consider the inclusion of a trigger mechanism once the Gas Substitution Roadmap is published. We will consult further on these matters as needed during this review period.

'Regulatory Change Event' means:

A change in a regulatory obligation or requirement that:

a. falls within no other category of Cost-Pass-Through Event; and
b. occurs during the course of an AA period; and
c. substantially affects the manner in which MGN provides Reference Services; and
d. materially increases or materially decreases the costs of providing those services.

'Service Standard Event' means:

A legislative or administrative act or decision that:

a. has the effect of:
   i. substantially varying, during the course of an AA period, the manner in which MGN is required to provide a Reference Service; or
   ii. imposing, removing or varying, during the course of an AA period, minimum service standards applicable to Reference Services; or
   iii. altering, during the course of an AA period, the nature or scope of the Reference Services, provided by MGN; and
b. materially increases or materially decreases the costs to MGN of providing Reference Services.

'Tax Change Event' occurs:

A tax change event occurs if any of the following occurs during the course of an AA period for MGN:

a. a change in a Relevant Tax, in the application or official interpretation of a Relevant Tax, in the rate of a Relevant Tax, or in the way a Relevant Tax is calculated;
b. the removal of a Relevant Tax;
c. the imposition of a Relevant Tax; and

in consequence, the cost to AGN of providing Reference Services are increased or decreased.

'Terrorism Event' means:

An act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of, or in connection with, any organisation or government), which:

a. from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear); and

b increases the costs to MGN of providing the Reference Service.

Note for the avoidance of doubt, in making a determination on a Terrorism Event, the AER will have regard to, amongst other things:

i whether MGN has insurance against the event;

ii the level of insurance that an efficient and prudent service provider would obtain in respect of the event; and

iii whether a declaration has been made by a relevant government authority that an act of terrorism has occurred.

'Retailer Insolvency Event' means:

Until such time as the National Energy Retail Law set out in the Schedule to the National Energy Retail Law (South Australia) Act 2011 of South Australia is applied as a law of Victoria, retailer insolvency event has the meaning set out in the National Gas Rules as in force from time to time, except that:

a where used in the definition of 'retailer insolvency event' in the National Gas Rules, the term 'retailer' means the holder of a licence to sell gas under the Gas Industry Act 2001 (Vic); and

b other terms used in the definition of retailer insolvency event in the Rules as a consequence of amendments made to that definition from time to time, which would otherwise take their meaning by reference to provisions of the National Gas Law, National Gas Rules or National Energy Retail Law not in force in Victoria, take their ordinary meaning and natural meaning, or their technical meaning (as the case may be).

Note: This retailer insolvency event will cease to apply as a Cost Pass Through Event on commencement of the National Energy Retail Law in Victoria.

'Insurer Credit Risk Event' means:

An event where:

a an insurer of MGN becomes insolvent; and

b as a result, in respect of an existing, or potential, claim for a risk that was insured by the insolvent insurer, MGN:

i is subject to a higher or lower claim limit or a higher or lower deductible than would have otherwise applied under the insolvent insurer's policy; or

ii incurs additional costs associated with self-funding an insurance claim, which would otherwise have been covered by the insolvent insurer.

Note for the avoidance of doubt, in making a determination on an Insurer Credit Risk Event, the AER will have regard to, amongst other things:

a MGN's attempts to mitigate and prevent the event from occurring by reviewing and considering the insurer's track record, size, credit rating and reputation; and

b in the event that a claim would have been made after the insurance provider became insolvent, whether MGN had reasonable opportunity to insure the risk with a different insurer.

'Insurance Cap Event' means:

An event where:

a MGN makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy;

b MGN incurs costs beyond the relevant policy limit; and

c the costs beyond the relevant policy limit increase the costs to MGN of providing the Reference Service.

For this Insurance Cap Event:

d a relevant insurance policy is an insurance policy held during the AA period or a previous period in which access to the pipeline services was regulated; and

e MGN will be deemed to have made a claim on a relevant insurance policy if the claim is made by a related party of MGN in relation to any aspect of the network of MGN's business.

Note for the avoidance of doubt, in making a determination on an Insurance Cap Event, the AER will have regard to, amongst other things:

i the insurance policy for the event;

ii the level of insurance that an efficient and prudent service provider would obtain in respect of the event; and

iii any assessment by the AER of MGN's insurance in approving the access arrangement for the Victorian and Albury gas distribution networks for the relevant period.

'Natural Disaster Event' means:

Any natural disaster including but not limited to fire, flood or earthquake that occurs during the Access Arrangement Period that increases the cost to the Service Provider in providing the Reference Service, provided the fire, flood or other event was not a consequence of the acts or omissions of MGN.

Note for the avoidance of doubt, in making a determination on a Natural Disaster Event, the AER will have regard to, amongst other things:

i whether MGN has insurance against the event; and

ii the level of insurance that an efficient and prudent service provider would obtain in respect of the event.

Materiality threshold is defined as:

For the purpose of any defined event, an event is considered to materially increase or decrease costs where that event has an impact of one per cent of the smoothed forecast revenue specified in the AER's final decision on this Access Arrangement, in the year of the Access Arrangement period that the costs are incurred.

14.5.7 Summary

We are proposing to broadly apply the same pricing structures in the next AA period except that we are proposing to remove the seasonal component to our tariffs that currently apply. This approach has been informed by our stakeholder engagement program and reflects a balancing of views provided by our customers and different stakeholder groups. We are also proposing the same price control to apply to our prices and the same process to vary prices over the next AA period.

15 Network Access

We have been standardising across our networks the Access Arranagements and Terms and Conditions which govern how users access our network.

IN THIS CHAPTER:

- **We propose to continue the process of standardising our Access Arrangement and Terms and Conditions across our networks.**

The Access Arrangement sets out our proposed price and terms and conditions under which we provide access to our network. Our reference service Terms and Conditions set the contractual arrangements between MGN 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'.[43] The terms and conditions of the Haulage Agreement typically reflect the AER approved terms unless otherwise agreed by the parties.

AGN and MGN came together to form AGIG towards the end of 2017. This AA review has presented an opportunity to align AGN and MGN Access Arrangements as well as the terms and conditions. As AGN has undertaken nearly ten years of reviews across Victoria, South Australia, Queensland and New South Wales, it was proposed that MGN be brought into alignment with AGN.

Our engagement therefore has been conducted using the existing AGN Victoria and Albury Access Arrangement and Terms and Conditions as a base, with subsequent adoption to MGN. This was accepted by retailers as a logical and efficient approach, particularly as AGN terms and conditions had been undergoing a long process of harmonisation.

The following sections outline the process we followed to develop our proposed terms of access to our MGN network over the next (2023/24 to 2027/28) AA period.

Our proposal is to align the Access Arrangement document and terms and conditions that applied to MGN in the current AA period with the AGN Victoria and Albury Access Arrangement and Terms and Conditions proposed for 2023/24 to 2027/28, with amendments specific to the MGN network. Attachments 15.1 and 15.2 explain changes made to the AGN Access Arrangement and documents used as a base for the MGN terms, as well the amendments specific to MGN.

15.1 Regulatory Framework

The requirements of an Access Arrangement are set out in NGR48. We are required to set out the amendments proposed to the Access Arrangement and provide the revised text as part of this Final Plan.[44] We are also required to specify the terms and conditions on which each reference service will be provided.[45]

15.2 Stakeholder engagement

Our Access Arraangement and Terms and Conditions proposed as part of this Final Plan have been subject to stakeholder engagement undertaken through a number of successive AA review processes. Consequently, they reflect the feedback we receive

[43] Network users are primarily gas retailers or self-contracting users of our networks.
[44] NGR52
[45] NGR 48(d)(ii))

from stakeholders as well as 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 AGN and Victorian and Albury and MGN networks. We then updated some of the terms on account of the feedback received from retailers and provided the retailers with another draft in April 2022.

15.3 Access Arrangement and terms and conditions review

15.3.1 Approach

AGN commenced a process of standardising terms across all its networks back in 2012.

MGN also considers there are many benefits to our customers from standardising terms of access as it promotes greater efficiency across the industry and reduces transaction costs.

Our approach to developing the proposed Terms and Conditions includes:

- Harmonising the proposed terms with the AGN South Australia 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 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 the drafts of our proposed Terms and Conditions; and
- Incorporating feedback from the Draft Plan on the Access Arrangement and proposed Terms and Conditions in preparing our Final Plan.

15.3.2 Key changes

We have used the Access Arrangement and Terms and Conditions that applied to AGN Victoria and Albury in the curent period as the base terms to apply to MGN in the next AA period. Attachments 15.1 and 15.2 identify the changes proposed from the AGN terms applicable in the current period, as well as the changes made which are specific to MGN.

Our engagment was on the basis of standardisation using the AGN terms. Two key issues were raised by retailers through the engagement process:

- Aligning credit support arrangements with other jurisidctions (where the National Energy Customer Framework (NECF) applies).
- Removing fixed charges for a disconnected site.

On the latter point, MGN already has a practice of not charging for disconnetced sites, which will now for part of our Access Arraangement and Terms and Conditions submitted with this Final Plan.

We will however maintain the current provisions relating to credit support. This reflects that:

- Credit support arrangements in Victoria are governed by the AA;
- In other jurisdictions where NECF applies, Part 21 of the NGR sets out credit support arranagements that apply in those jurisdictions;
- In Victoria, a policy decision was made not to adopt the NECF and the credit support arrangements in Part 21 were specifically not adopted;
- There are differences between the two credit support regimes and there are pros and cons to both. The current credit support arrangements in the AA have applied for some time and are simple to apply. It remains important for such credit support arragements to be maintained, particularly in light of recent market pressures; and
- Given the previous policy position taken in relation to Part 21, if a change to the credit support arrangements was to be made, that should be done by way of a change to the NGR rather than through an amendment to the AA.

We note that if the credit support arrangements in the AA Document were to be changed to align with NECF jurisdictions, consequential changes would also need to be made, such as to the materiality threshold that applies to the retailer insolvency cost pass-through to align with Part 21, which has no materiality threshold. Consideration would also need to be given to how the the credit support arrangements would be transitioned.

We note that we have made one substantive change to the credit support arrangements in the AA Document to broaden the credit rating agencies that may provide an acceptable credit rating to include an equivalent rating by Moody's Investors Services (see clause 6.4 of the AA Document and Attachment 15.2.)

Attachments 15.1 and 15.2 provide a summary of the changes to the AGN AA Document and Terms and Conditions in the current period which have been used as a base and attachment 1.1 identifies how our Access Arrangement complies with the relevant NGR requirements.

For reference, we also provide the MGN AA Document and Terms and Conditions that applied in 2018-2022 AA period as Attachment 15.3.

15.4 Summary

The Access Arrangement and 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 been aligned to the AGN Terms and Conditions, which have gone through considerable consultation with stakeholders over the past 10 years.

We consider that the process of standardisation and harmonisation of our Terms and Condition across our networks is consist with achieving lowest sustainable costs for our customers.

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

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