Victoria distribution network Access Arrangement Variation Proposal

January – June 2023

April 2022

Multinet Gas Networks

Contents

We are Multinet Gas Networks. We deliver gas safely and reliably to more than 700,000 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.

CEO Foreword

I am pleased to present the Multinet Gas Networks (MGN) Variation Proposal for the period January to June 2023.

This document sets out the key parameters for the variation of the current Access Arrangement (AA) period for the six month period January to June 2023, following the Victorian government's decision in April 2019 to extend the end date of the current AA from 31 December 2022 to 30 June 2023. The proposal sets out the revenue and prices applicable to the extension period.

MGN is part of Australian Gas Infrastructure Group (AGIG), one of Australia's largest gas infrastructure businesses. Through MGN we serve over 700,000 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 residential, commercial and industrial customers.

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

This Variation Proposal actions the Victorian government's decision to extend the end date of the current AA from 31 December 2022 to 30 June 2023. In doing so, it holds prices stable on 1 January 2023, with prices to increase by CPI only. It also provides for an adjustment to revenues in the next AA period (1 July 2023 to 30 June 2028) that ensures both customers and MGN are neutral to the extension of the current AA period by six months to 30 June 2023.

Craig de Laine

Chief Executive Officer

Purpose of this proposal

Regulatory Framework

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

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

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

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

Transitional arrangements

In line with the Order, the AER released a Position Paper on 8 November 2021 that sets out transitional arrangements for the six-months. The AER proposes to:

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

Variation proposal

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

How to read this proposal

The first two chapters of this document provide an overview of our variation proposal and our business.

Each subsequent chapter then steps through the regulatory building blocks that form our required revenue for the six month extension period. These are:

- *Operating expenditure* (opex) – the expenditure we require to run our business day-to-day (Chapter 3);
- *Capital expenditure* (capex) – the investment in our assets required to deliver services to our customers (Chapter 4);
- *Capital base* – the total value of our investment in the Victorian and Albury networks, which we have not

yet recovered from customers and therefore need to finance (Chapter 5);

- *Financing costs* – the cost of financing our capital base and meeting our tax obligations (Chapter 6);
- *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 7); and
- *Demand forecasts* – the total amount of services we forecast our customers will demand over the period (Chapter 8).

In the last chapter, we outline how we have calculated the total revenue required, the prices for our services and the revenue adjustment to be applied in the next AA period (Chapter 9).

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

Next steps

The AER will review and undertake its own engagement process on our variation proposal. We also encourage our customers and stakeholders to provide any feedback:

online at gasmatters.agig.com.au

by mail

in person

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

1 Overview

Our Variation Proposal outlines the revenue and prices applicable to the extension period and related revenue adjustments required in the next AA period, commencing 1 July 2023.

IN THIS CHAPTER:

- **We have set the key parameters for the 1 January to 30 June 2023 extension period in line with the Order in Council and AER Position Paper for the AA Variation proposal.**
- **Consistent with the Order, we are proposing 2022 tariffs (indexed for inflation) apply to the 1 January to 20 June 2023 extension period.**

The Victorian gas distribution access arrangement (AA) periods will now be based on financial years rather than calendar years. To facilitate this, the current 2018-2022 AA will be extended by six months to 30 June 2023.

This section highlights how we have developed our Variation proposal, and the key parameters used to calculate revenue and prices for the six month period 1 January to 30 June 2023.

1.1 Developing this plan

An Order in Council (the Order) was published on 30 September 2021 under section 64 of the *National Gas (Victoria) Act 2008*. The Order requires each business to submit a variation proposal by 1 April 2022.

In November 2021, the AER released its Position Paper: Approach to six month extension of access arrangements for Victorian gas distributors (Position Paper). The Position Paper set out a proposed approach to determine revenue and prices for the 1 January to 30 June 2023 extension period. We have followed this approach in developing this Variation Proposal.

1.2 Key parameters

The following sections summarise each of the key parameters used to calculate revenue and prices for the six month extension period.

1.2.1 Opex

Our opex including ancillary reference services (ARS) and debt raising costs for the six month extension period is $45 million. Opex has been calculated using a simple trend forward methodology consistent with the Order and Position Paper.

More information on how we calculated our opex for the six month extension period can be found in Chapter 3.

1.2.2 Capex

Our capex for the six month extension period is $38 million. Capex has been calculated using a simple trend forward methodology consistent with the Order and Position Paper.

More information on how we calculated our capex for the six month extension period can be found in Chapter 4.

1.2.3 Capital base

We have rolled forward the Regulatory Asset Base (RAB) to 1 January 2023 to determine an opening asset value of $1,389 million ($nominal) on 1 January 2023 using the AER's Roll Forward Model.

More information on how we have rolled forward our capital base can be found in Chapter 5.

1.2.4 Financing costs

The rate of return for the six month extension period is 4.68%. We have determined the rate of return and its components, the cost of debt and cost of equity, using the AER's Modified 2018 Rate of Return Instrument developed for the six month extension period.

The tax allowance for the six month extension period is $3 million and has been calculated consistent with the approach applied in the current AA period.

More information on how we calculated the rate of return and tax allowance for the six month extension period can be found in Chapter 6.

1.2.5 Incentives

All incentive payments related to the operation of the opex and capex incentive schemes in the current AA period will be applied in the next AA period, commencing 1 July 2023.

The opex incentive scheme will continue to apply to the six month extension period. To ensure any gains or losses under the scheme are retained for a period of five years only, a six month adjustment will be made in the calculation.

Consistent with the AER's Position Paper, the capex incentive scheme will not apply to the six month extension period.

More information on incentives for the six month extension period can be found in Chapter 7.

1.2.6 Demand

We have used Core Energy's (Core) forecast of demand to determine tariff revenue. As the relevant period is the first half of calendar year 2023, we have averaged Core's forecast of 2022/23 and 2023/24 to derive a proxy calendar year forecast. We have then used the average distribution of demand to determine the demand we expect to see in the first half of the 2023 calendar year.

More information on our forecast demand for the six month extension period can be found in Chapter 8.

1.2.7 Revenue and Prices

Total building block revenue for the six month extension period is $94 million.

We are applying the RBA's forecast of inflation for 2021/22 to the approved 2022 tariffs.

The forecast tariff revenue for the period (price x forecast demand) is $92 million. As forecast tariff revenue for the six month extension period is lower than the total building block revenue calculated for the period, there will be a positive revenue adjustment in the next AA period of $2 million. This adjustment ensures that customers and AGN are neutral to the extension of the current AA period by six months to 30 June 2023.

More information on revenue and prices for the six month extension period can be found in Chapter 9.

2 Our Business

We deliver gas safely and reliably to more than 700,000 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.**

Multinet Gas Networks is part of AGIG, one of the largest gas infrastructure businesses in Australia.

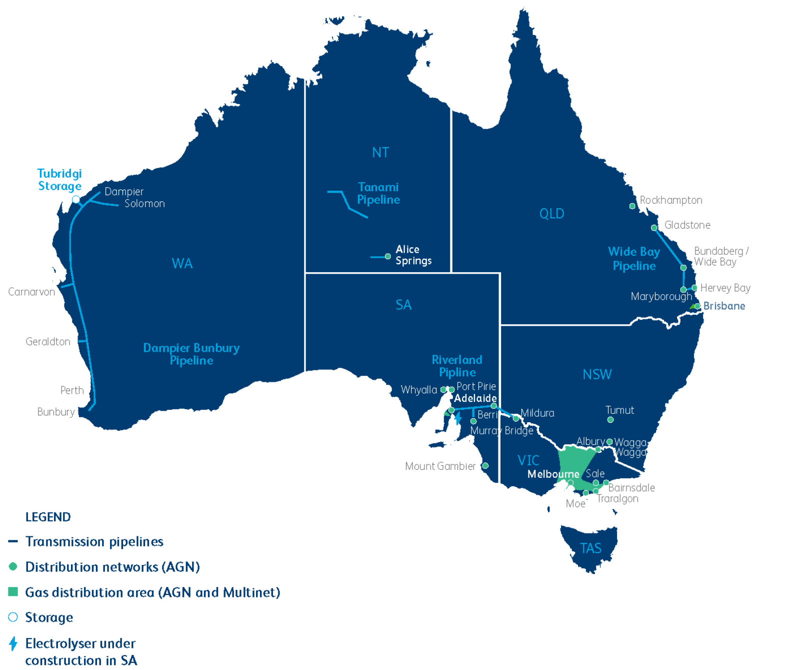
2.1 About AGIG

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

In 2017 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.

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

Figure 2.1 AGIG's operations across Australia



2.2 Our vision

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

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

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

The activities and investments in this Draft Plan are designed to achieve these objectives. The chapters that follow will discuss our plans in the context of these objectives alongside the requirements of the NGL and NGR.

We also publicly report against our vision, most recently in our 2020 Annual Review.

2.3 Our values

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

Our vision

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

Delivering for customers

- Public safety
- Reliability
- Customer service

A good employer

- Health and safety
- Employee engagement
- Skills development

Sustainably cost efficient

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

Our values

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

Perform

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

Trust

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

Respect

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

One Team

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

2.4 Delivering for customers

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

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

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

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

2.5 Zero harm

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

Our Zero Harm Principles (shown in Figure 2.2) highlight areas of risk in our operations where we have non-negotiable rules for our staff and contractors to follow.

These rules are essential to keep our workforce and the public safe. They also help us create a strong safety culture where every employee is personally committed to managing health and safety.

Figure 2.2: Our Zero Harm Principles

2.6 The gas supply chain

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

Our customers purchase gas from retailers, which is delivered directly to them through our Victorian and Albury distribution networks.

2.7 Our role in Victoria

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

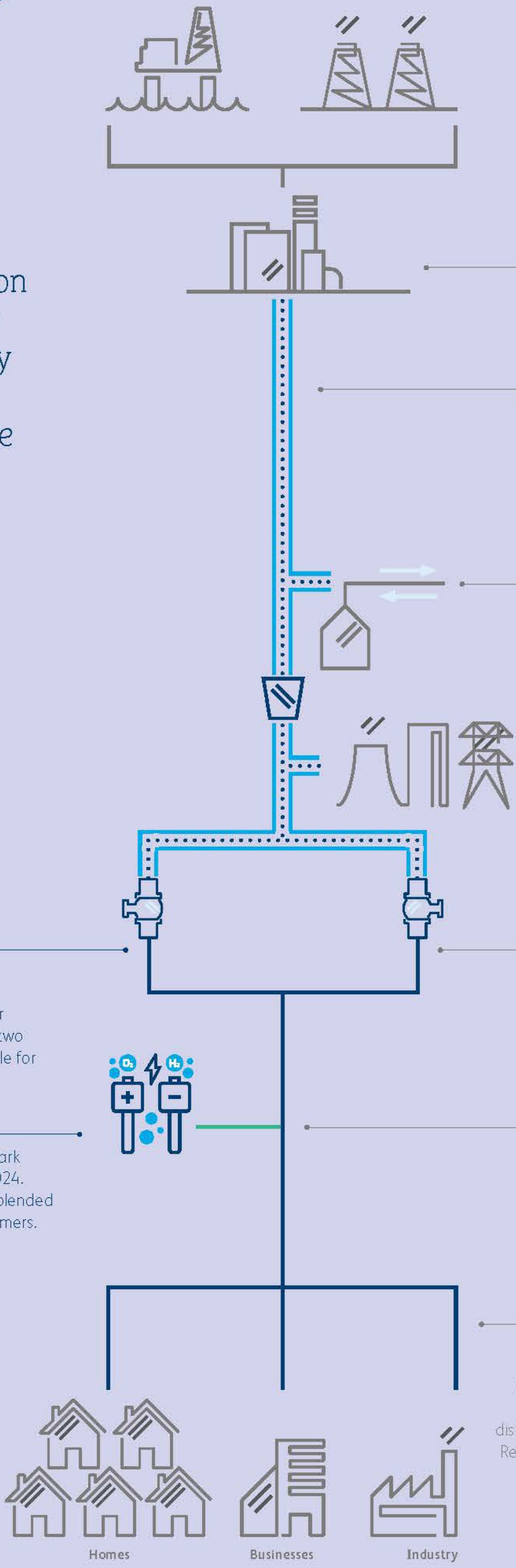
The following page shows the location and key features of the MGN network. The network is more than 9,978 km long, serving residential, commercial and industrial business customers throughout Melbourne's inner and outer east, the Yarra Ranges and South Gippsland.

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

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

The Gas Supply Chain

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



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

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

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

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

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 lower 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 to customers. Biomethane and renewable hydrogen facilities are under development across the country.

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

9,978
Kilometres of mains

54PJ
Gas delivered in 2020

717,604
Customers

8.1
Customer satisfaction score

2.8 Our low carbon strategy

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

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

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

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

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

Through HyP Murray Valley we expect to deliver a 10% renewable 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.

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

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

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

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

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

3 Operating expenditure

We have calculated operating expenditure for the six month period using a simple trend forward methodology.

IN THIS CHAPTER:

- **Our opex forecasts have been developed using the simple trend forward methodology outlined by the AER in its Position Paper.**
- **This results in a total opex allowance of $45 million for the six months January to June 2023.**

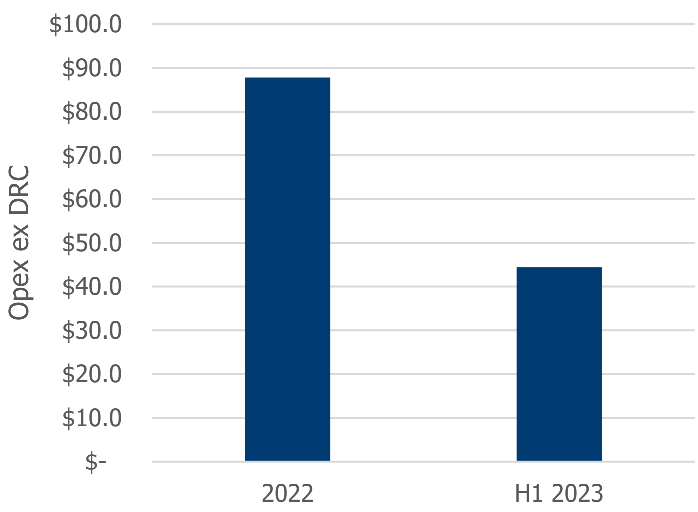
The operating expenditure (opex) we incur supports the safe, efficient and reliable delivery of gas to homes and businesses every day. It ensures we can meet the service expectations of our customers and the day-to-day needs of our workforce.

Consistent with the approach outlined in the AER's Position Paper we have applied a simple trend forward methodology to calculate the opex allowance for the six months January to June 2023.

Total opex excluding debt raising costs for the six month period is forecast to be $45 million (see Figure 3.1 below).

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

Figure 3.1: Comparison of opex



3.1 Regulatory framework

The Order and Position Paper set out requirements for our forecast opex for the extension period.

The Order requires that forecast opex for the extension period either meet the criteria in NGR91 or not exceed half of the approved opex forecast for 2022 adjusted for inflation and rate of change.[2]

The Position Paper proposes to apply a rate of change to half the 2022 approved opex forecast, excluding debt raising costs. The rate of change is equal to three quarters the rate of change used for 2022 (representing the nine months between the middle point of 2022, being June 2022, and the middle point of the extension period, being March 2022). Debt raising costs are a category

[2] Order in Council, cl 8.

specific forecast, and the same benchmarking approach to forecasting these costs in the current AA period will be applied to forecasting these costs for the extension period.[3]

3.2 How we have developed the opex forecast

Our opex forecast for January to June 2023 has been developed using a simple trend forward methodology. This approach takes the opex allowance excluding debt raising costs from calendar year 2022, trended forward by nine months and halved. We have used actual June CPI to inflate to $2022/23.

Debt raising costs have been calculated separately in the building block model. The use of this approach is consistent with the AER's proposed approach and the approach required by the Order.

3.3 Our opex forecast for H1 2023

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

3.3.1 2022 opex allowance

Table 3.1: Establishing the 2022 opex allowance for forecasting opex for the extension period ($million, 2022/23)

Category	2022 opex allowance
Total opex ($million, 2017)	79.2
Minus category specific forecasts (debt raising costs)	0.6
Inflation to $2022/23)	9.2
Full year opex	**87.8**

3.3.2 Trend

The trend considers 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.

We have calculated the trend for the nine months between June 2022 to March 2023 by taking nine twelfths of the trend rate applied to the 2022 year. The rate of change is 1.5% per year, or 1.2% adjusted for 9 months.

3.3.3 Category specific forecasts

As noted above, separate forecasts have been developed for debt raising costs.

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 for the extension period is $0.3 million which has been calculated using the AER's standard benchmark method.

3.3.4 Summary

Table 3.2 sets out our forecast opex of $45 million for H1 2023.

Table 3.2: Opex forecast summary ($ million, 2022/23)

	H1 2023
Half year opex	43.9
Trend	0.5
Total opex forecast (ex debt raising costs)	**44.4**
Debt raising costs	0.3
Total opex	**44.7**

[3] Position Paper, p 7-8.

4 Capital expenditure

We have calculated capital expenditure for the six month period using a simple trend forward methodology.

IN THIS CHAPTER:

- **Our capex forecasts have been developed using the simple trend forward methodology outlined by the AER in its Position Paper.**
- **This results in a total capex allowance of $38 million for the six months January to June 2023.**

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

Consistent with the approach outlined in the AER's Position Paper we have applied a simple trend forward methodology to calculate the capex forecast for the six months January to June 2023.

Total capex for the six month period is forecast to be $38 million (see Table 4.1).

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 forecast for the January to June 2023 period.

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

Table 4.1: Total forecast capex by RAB category ($million, 2022/23)

Category	2022 forecast capex allowance ($Dec 2017) (A)	Inflation adjustment ($Dec 2017 to $Dec 2022) (B)	H1 2023 ($Dec 2022) Half of (A)+(B)
Transmission and distribution	44.9	4.2	24.6
Services	16.1	1.5	8.8
Cathodic Protection	0.2	0.0	0.1
Supply Regs/Valve stations	1.6	0.1	0.9
Meters from 2018 (New)	4.5	0.4	2.5
IT	10.1	0.9	5.5
SCADA	0.6	0.1	0.3
Other	0.1	0.0	0.1
Buildings	-	-	-
Contributions included in the above	8.3	0.8	4.5
Total capex (net of contributions)	**69.8**	**6.6**	**38.2**

4.1 Regulatory framework

The Order and Position Paper set out requirements for the capex for the extension period.

The Order requires forecast capex for the extension period to either be consistent with NGR79 or not to exceed half the average of the corresponding forecast capex approved by the AER over the current AA, adjusted for inflation over the five years 2017 to 2022.[4]

The Position Paper proposes to apply half the forecast capex allowance for 2022, escalated by inflation.[5]

4.2 How we have developed the capex forecast

Our capex forecast for the six month extension period has been developed using a simple trend forward methodology which takes half of the approved capex allowance in 2022, adjusted for inflation. We have used June CPI lagged by one year consistent with the Roll Forward Model.

4.3 Summary

The total capex allowance for H1 2023 is $38 million.

[4] Order in Council, cl 8.
[5] Position Paper, p 9.

5 Capital Base

This chapter discusses the movements in our capital base in the current AA period and for the six months January to June 2023.

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 have rolled forward the capital base to the start of the extension period.**

We adjust our capital base for capex, depreciation and inflation using actual information over the current AA period and forecast information over the six month extension period.

5.1 Regulatory framework

We are required to adjust our capital base to reflect capex (net of any amounts contributed by our customers), inflation and depreciation. We are also required to remove the value of any assets that we have sold and reflect the reuse of redundant assets in the current AA period.

Our forecast of depreciation is required to be set:

- so that our prices vary over time in a way that promotes the efficient growth of the services provided by our business;
- so that our assets are depreciated over their economic life;
- to allow for changes in the expected economic life of a particular asset;
- so that an asset is depreciated only once; and
- to allow for our reasonable needs for cash flow to cover our costs.

Further, the Order in Council and AER Position Paper outline that the standard Roll Forward Model be used to establish the opening capital base as at 1 January 2023.

5.2 Capital Base at 1 January 2023

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

Table 5.1 shows the adjustments we have made to our capital base over the current AA period.

The closing value of the capital base forms the opening capital base for the six month extension period.

5.3 Capital Base as at 30 June 2023

This section discusses the forecast adjustments made to the capital base over the six month extension period.

5.3.1 Capital Expenditure

The forecast capex was discussed in Chapter 5 of this Variation Proposal and is reproduced in Table 5.2, 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 5). The AER makes this adjustment to account for the fact that we do not earn a return on the capex within the year it was spent.

Table 5.1: Roll Forward of the Capital Base 1 January 2018 to 31 December 2022 ($nominal, million)

	2018	2019	2020	2021	2022
Opening Capital Base	1,192.9	1,250.2	1,297.6	1,330.1	1,337.8
Less Depreciation	-62.9	-66.3	-70.2	-72.4	-77.8
Plus Conforming Capex	97.1	87.7	82.1	84.8	86.1
Plus Actual Inflation	23.1	26.0	20.7	-4.6	51.5
Less Adjustment					8.9
Closing Value	**1,250.2**	**1,297.6**	**1,330.1**	**1,337.8**	**1,388.6**

Note: Totals may not add due to rounding.

Table 5.2: Forecast Capex January to June 2023 including half a year of return

Asset Category	H1 2023
Transmission and distribution	20.4
Services	9.0
Cathodic Protection	0.1
Supply Regs/Valve stations	0.9
Meters	2.5
IT	5.6
SCADA	0.4
Other	0.1

Table 5.3: 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

5.3.2 Forecast Depreciation

We have continued to apply the asset lives that were approved by the AER for the current AA period (as shown in Table 5.3). In determining forecast depreciation for the six month extension period, we have applied the 'year-by-year' tracking approach. This approach is consistent with that used by the AER for other networks, including our AGN South Australia network.

5.3.3 Inflation

Forecast inflation is a critical element in determining our total revenue and pricing. As explained earlier, forecast inflation is used to adjust the capital base over the next AA period. This forecast is later updated for actual inflation when adjusting the capital base for the previous AA period.

Forecast inflation is also used in determining the total revenue that we can recover (and hence the prices we can charge). This is 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 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 the

forecast inflation adjustment applied to the capital base.

We have used the RBA's forecast of inflation for the extension period in our proposal.

5.3.4 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. Forecast regulatory depreciation that is used to determine assumed total revenue for the six month extension period has been determined using the AER's preferred approaches to calculating both depreciation and inflation.

5.3.5 Forecast Capital Base

The forecast capital base over the extension period, taking into account forecast depreciation, capex and inflation, is set out in Table 5.4. This shows a closing capital base of $1,413 million as at 30 June 2023 in nominal dollar terms.

Table 5.4: Forecast Capital Base to 30 June 2023 ($nominal, million)

	H1 2023
Opening Capital Base	1,388.6
Less Depreciation	-33.80
Plus Conforming Capex	38.9
Plus Actual Inflation	19.0
Closing Value	**1,412.6**

Note: Totals may not add due to rounding.

5.4 Summary

We have adjusted our capital base over the current AA period and six month extension period to reflect actual/forecast capex, depreciation and inflation.

6 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:

- **We have applied the AER's Modified Rate of Return Instrument for the six month extension period for Victorian gas distribution networks in line with the Order and Position Paper.**
- **Based on forward market estimates, the rate of return is 4.68% (compared to 5.75% at the start of the current period).**

In this Variation Proposal, the allowed rate of return and the cost of tax have been calculated according to the AER's Modified Rate of Return Instrument and consistent with the tax treatment applied in the current AA period (i.e. does not apply the outcomes of the AER's 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 six month extension period.

6.1 Regulatory framework

The NGR provide a framework for calculating the return on the projected capital base (rate of return).

In October 2021, the AER published the *Modified Rate of Return Instrument – Six months extension period for Victorian Gas Distribution Network Service Providers* which details the approach we are required to follow for calculating the rate of return under the NGR for the six month extension period.

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.

We have followed the AER's approach in respect of all aspects of our financing costs and tax allowances.

6.2 Financing Costs

Our financing costs are determined based on an estimate of the return on equity and the return on debt over the six month extension period, which are together referred to as our rate of return and are discussed in this section.

6.2.1 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 Modified Rate of Return Instrument, which results in a return on equity of 5.75% over the six month extension period (see Table 6.1).

Table 6.1: Indicative return on equity

Parameters	Value
Equity risk-free rate	2.09%
Beta	0.6
Market Risk Premium	6.10%
Return on equity	**5.75%**

These values are indicative and were measured using February 2022 information. The AER will use updated information consistent with the nominated averaging period in making its decision.

6.2.2 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. The AER has adjusted its standard 10-year trailing average to account for the extra half a year in an NPV-neutral manner.

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 Modified Rate of Return Instrument yields a return on debt of 3.97%, which we have applied in this Variation Proposal. As with the return on equity, the AER will use updated information consistent with the nominated averaging period in making its decision.

6.2.3 Rate of Return

In its Modified 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 (5.75%) and return on debt (3.97%) results in an overall rate of return of 4.68% in the six month extension period.

6.3 Cost of Tax

We have calculated the cost of tax consistently with the approach applied in the current AA period (i.e. we have not reflected the outcomes of the AER's December 2018 Tax Review in this Variation Proposal). This approach is consistent with that outlined in the Order and Position Paper.

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 is $5 million.

6.3.1 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 9);
- *Opex* – which is a specific building block that is used to determine total revenue (see Chapters 4 and 9);
- *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 3.97% 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.

6.3.2 Value of Imputation Credits

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

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

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

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

6.3.3 Tax Depreciation

Our approach to determining tax depreciation in this Variation Proposal has not changed from that applied to the current AA period.

6.3.4 Tax Asset Base

The opening TAB of $763 million ($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 6.2).

6.4 Summary

Our financing and tax costs collectively account for around 31% of our total costs. For the purposes of this Draft Plan, we have applied the AER's Rate of Return Instrument and the AER's Tax Review in determining our financing and tax costs.

This results in a rate of return of 4.68% (see Table 6.3) and a Net Tax Allowance of $3 million.

Table 6.2: Roll forward of the tax asset base ($million, nominal)

	H1 2023
Opening tax asset base	763.0
Plus gross capex	43.3
Less tax depreciation	15.9
Closing tax asset base	**790.4**

Note: totals may not add due to rounding

Table 6.3: Indicative AER Rate of Return and Gamma

Parameters	
Return on Equity	5.75%
Return on Debt	3.97%
Overall Rate of Return	4.68%
Gamma	0.585

7 Incentives

The opex scheme will continue to apply to the six month extension period, however the capex scheme will not. Any revenue adjustments related to the operation of both of these schemes in the current AA period will be applied in the next AA period (i.e. will be included in the prices to apply from 1 July 2023).

IN THIS CHAPTER:

- **There will be no carry overs from the operation of the opex efficiency benefit sharing scheme (EBSS) and capital efficiency sharing scheme (CESS) applied to the six month extension period. Any applicable revenue adjustments from the operation of these schemes will be applied in the next AA period (July 2023 to June 2028).**
- **The opex scheme will apply in the six month extension period to ensure there is a continuous incentive to achieve ongoing efficiency gains.**
- **The capex scheme will not apply in the six month extension period as the capital allowance set for the period has not had regard to the drivers for required investment in that period.**

We support the use of effective, outcome-based incentive schemes that promote the long-term interests of our customers.

Incentive schemes are often used by regulators to:

- strengthen a service provider's incentive to continuously seek out efficiency and performance improvements and share the benefits with customers;
- balance incentives between opex and capex so that the most efficient expenditure mix is chosen;
- pursue efficiencies while improving or maintaining service quality; and
- encourage investment in innovation in areas that can provide longer-term benefits to our customers.

Our network currently operates under the opex efficiency benefit sharing scheme (EBSS) and the contingent capex efficiency sharing scheme (CESS).

For the purpose of the six month extension period:

- the opex scheme will apply to ensure the continuous incentive to achieve ongoing efficiency gains is maintained; and
- the capex scheme will not apply as the capital allowance set for the period has not had regard to the drivers for

required investment in the period.

7.1 Regulatory Framework

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

In keeping with this objective, the NGR provide for gas networks to have incentive schemes apply to encourage the efficient provision of services.[6]

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

- efficient investment in (or in connection with) the network;
- the efficient provision of services; and
- the efficient use of the network.[7]

The Order allows the AER to decide revenue increments or decrements from the operation of incentive mechanisms in the current AA period do not apply to the applicable AA extension period as well as make any modifications to the application of the incentive mechanism for the extension period.

The Position Paper proposes the CESS would not apply, the efficiency carryover mechanism (opex EBSS) would apply and any revenue increments or decrements in relation to the schemes in the 2018-22 period could apply from 1 January 2023.

We have applied this approach in this Variation Proposal, however, have opted to apply any revenue increments or decrements in relation to the schemes in the 2018-22 period from 1 July 2023, consistent with our Draft Plan for the five years July 2023 to June 2028.

7.2 Opex EBSS

Our network is currently subject to an opex EBSS which will apply in the six month extension period.

7.2.1 How the EBSS works

The EBSS is a key element of our opex forecasting approach which is designed to provide a continuous incentive to pursue opex efficiency improvements in any particular year of an AA period and to share any efficiency gains (or losses) with our customers.

The EBSS operates in a symmetric manner, which means that we are rewarded if there is an incremental efficiency gain, and penalised if there is an incremental efficiency loss.

To ensure that we have an incentive to pursue efficiency gains evenly throughout the AA period, we are able to retain the benefit of any efficiency gain (or incur the cost of any efficiency loss) for five years. After the relevant AA period, the benefit (cost) is passed through to our customers in the following AA period.

In effect, the EBSS provides for 70% of the efficiency gains (or losses) to be passed through to our customers in the form of lower (higher) prices.

Adjustments required for the six month extension period

To ensure any efficiency gains or losses are retained for a period of five years, a further adjustment must be made to account for the current AA period six month extension.

Revenue adjustments to be applied in the next AA period

The revenue adjustment in the next AA period as a result of the operation of the EBSS (and efficiency gains achieved) in the current AA period has been dealt with in our Draft Plan for the next AA period.

Although the Position Paper suggests revenue adjustments could be applied from 1 January 2023. Any application to the building block revenue would not be passed through to customers until the next AA period and therefore we consider it is simpler to apply any revenue increments or decrements from 1 July 2023.

We will provide an update of the revenue adjustments from the application of the EBSS in the current AA period when we submit our Final Plan for the next AA period on 1 July 2022.

7.3 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.

[6] NGR 98
[7] NGL 24(3)

The CESS will not apply for the six month extension period

The contingent CESS will not apply to the six month extension period. The contingent CESS to apply in the next AA period has been dealt with in our Draft Plan for the next AA period.

Revenue adjustments to be applied in the next AA period

Similar to the EBSS, the revenue adjustment in the next AA period as a result of the Contingent CESS in the current AA period has been dealt with in our Draft Plan for the next AA period.

We are proposing that any revenue increments or decrements from the operation of the EBSS apply to the next AA period, as opposed to the extension period. This was noted as an option within the AER's Position Paper, and we consider it is simpler to apply any revenue increments or decrements from 1 July 2023, consistent with the approach we took in our Draft Plan for the five year period July 2023 to June 2028.

We will provide an update of the revenue adjustments from the application of the Contingent CESS in the current AA period when we submit our Final Plan for the next AA period 1 July 2022.

7.4 Summary

In the six month extension period the existing EBSS will continue to apply, but the Contingent CESS will not.

The revenue adjustments related to the application of these incentive schemes in the current AA period will be calculated and applied in the next AA period (July 2023 to June 2028).

To ensure any gains or losses under the EBSS are retained for a period of five years only, a six month adjustment will be made in the calculation.

8 Demand Forecasts

Our demand forecast for the six month extension period reflects the forecasts that have been independently developed for the next AA period, and a historic average of the percentage of demand that falls between January and June.

IN THIS CHAPTER:

- **Our demand forecast for the six month extension period has been independently determined applying methodologies consistent with those approved previously by the AER.**

The demand for our services drives our operations and is a determinant of our prices.

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

Reflecting the differences in the nature of demand for our services, separate demand and customer connection forecasts have been developed by independent expert Core Energy and Resources ('Core Energy'), for our:

- residential customers;
- commercial customers (business customers who use less than 10 terajoules of gas each year); and
- industrial customers (our largest business customers who consume more than 10 terajoules of gas each year).

In the next AA period, Core Energy forecasts the demand for natural gas for our:

- residential customers to fall by 3.3% per year, in response to a range of external factors, such as State and Federal government policy initiatives, higher projected wholesale gas prices, improved appliance and dwelling efficiency, and lower new dwellings growth;
- commercial customers to rise by 0.6% per year, largely in line with recent trends in consumption per connection; and
- industrial customers to rise by 0.5% 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 2.4% per year in the next AA period.

The demand forecast we have used for the six month extension period reflects this forecast.

The following sections provide detail on the relevant regulatory framework, the forecasting method and the demand forecasts themselves.

8.1 Regulatory framework

Our AA proposal must include the forecast demand for reference services. The Order does not prescribe an approach to the preparation of our demand forecast, however the NGR provides that our 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's consultants have assessed Core Energy's forecasts against these principles and concluded that their forecasts were consistent with them.

8.2 Residential and Commercial Demand

8.2.1 How our forecasts were developed

The methodology Core Energy has used to forecast our residential and commercial customers' demand is summarised in Figure 8.1.

The methodology is consistent with the approach that was used to develop the demand forecasts for the current AA period for our South Australia and 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

Figure 8.1: Forecasting method used for residential and commercial customers

Step 1
Normalise historic data

1. Normalise the historic demand per connection data for both residential and commercial customers to remove fluctuations due to weather.
2. Use the normalised data to calculate an historic annual average growth in demand per connection.
3. Adjust for the effect of energy price changes from the historic growth.

Step 2
Forecast demand per connection

Determine the forecast demand per connection by adjusting the normalised data in Step 1 to account for drivers that are not reflected in the historic data, e.g. the effects of Government policy or future energy price movements.

Step 3
Forecast Connections

Derive a forecast of the net connections that will occur in the next AA period for residential customers (largely based on forecast new dwelling growth) and commercial customers (largely based on forecast economic activity).

Step 4
Forecast Demand

Determine the forecast demand for both residential and commercial customers by multiplying the forecast consumption per connection from Step 2 by the total forecast connections for each customer group from Step 3.

point and historic trends used to forecast gas demand are not unduly affected by abnormal weather conditions (see Step 1.1 in Figure 8.1).

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 8.1).

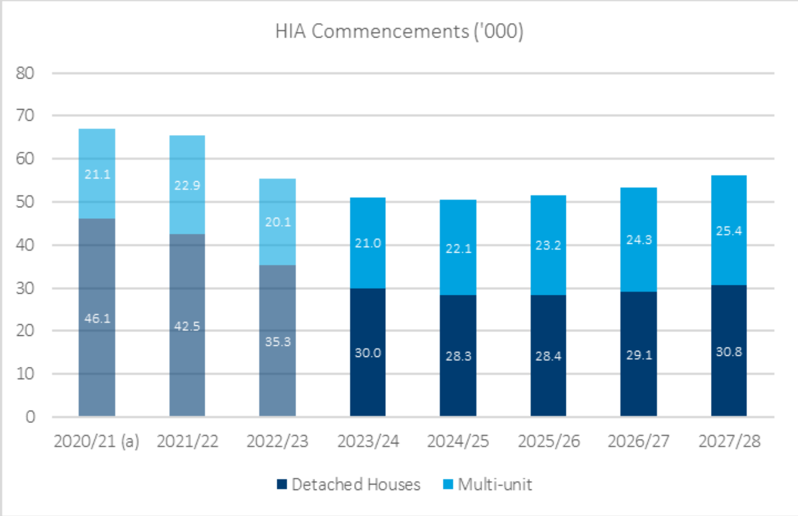
Forecast new dwelling growth

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 8.2).

As Figure 8.2 shows, HIA has projected an increase in new dwelling commencements, particularly multi-unit dwellings over the course of the next AA period. Total Victorian

Figure 8.2: HIA Forecast of new dwelling commencements



commencements are projected to increase from approximately 51,000 dwellings in 2023/24 to 56,200 dwellings in 2027/28, with AGN Victoria and Albury assumed to capture a 27% share.

Multi-unit dwellings are the key driver of this increase with 4,400 additional multi-unit dwellings to be constructed in 2027/28 compared with 2023/24, whereas there will be 780 more detached dwellings constructed over the same period.

COVID-19

Victoria's COVID-19 lockdowns persisted throughout much of 2020 and 2021 and had different impacts on the residential and commercial sectors.

Residential customers who stayed at home rather than attending their workplaces during business hours required more heating than usual during the cooler months of 2020 and 2021 because they were often at home rather than their workplaces. Residential gas demand in 2020 was 5.0% higher than in 2019. Demand was also driven higher by the colder weather in 2020 even when normalising for weather, it is clear that COVID-19 lockdowns increased residential demand.

Conversely, gas demand in the commercial segment was negatively impacted due to restrictions on businesses trading during lockdown. This drove commercial demand 13.7% lower in 2020 (despite the colder weather).

Core Energy has adjusted for the effects of COVID-19 by excluding demand data since the beginning of FY20 from the consumption trend.

8.2.2 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 decline by 0.4% per year in the next AA period. For this Variation Proposal we have derived a view of customer numbers from Core's forecast which is equivalent to 31 March 2023 which is the midpoint of the 6 month extension period.

The forecast of new connections is driven by HIA's forecast of new dwellings. The HIA has formed the view that in the medium term, the COVID-19 pandemic will have a material impact on the drivers for housing demand, including density, location and type of housing. The HIA sees a shift away from construction in large cities such as Sydney and Melbourne in favour of regional areas, which has reduced the level of construction activity expected during the AA period.

Consumption per connection

Core Energy is also projecting that consumption per residential connection will fall by around 2.9% per annum over the next AA period. Our forecast for the six month extension period uses the Core forecast to derive a proxy 2023 calendar year forecast and then uses historical volumes to forecast the demand expected in the six month extension period.

The key drivers of this decline include improved appliance and dwelling efficiency driven by both technological improvement, Victorian Government policy and higher expected wholesale gas prices over the AA period. This drives the substitution of gas appliances for their electric equivalent (for example, substituting gas heating for electric reverse cycle air-conditioning).

Figure 8.3: Residential connections forecast

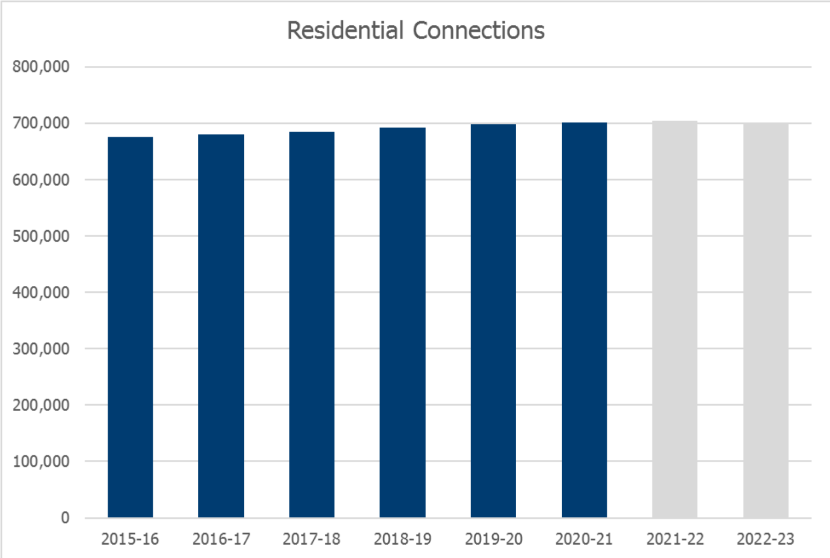


Figure 8.4: Residential Consumption per Connection

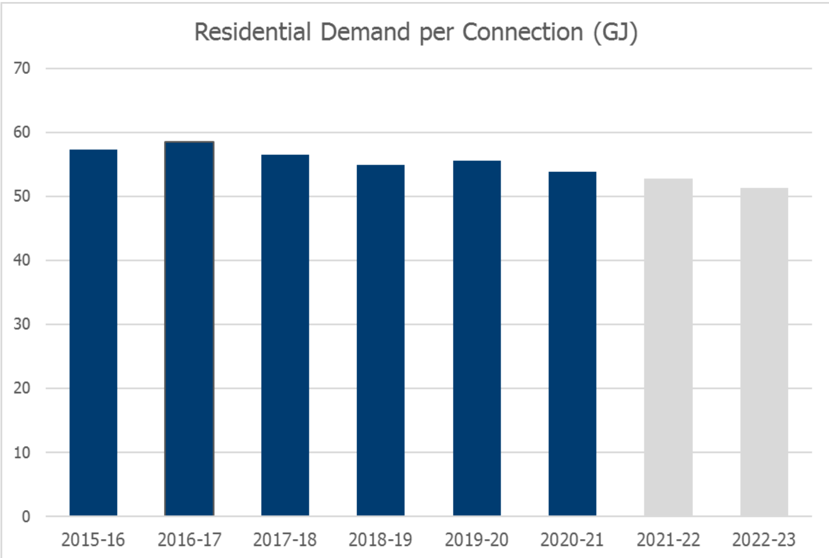
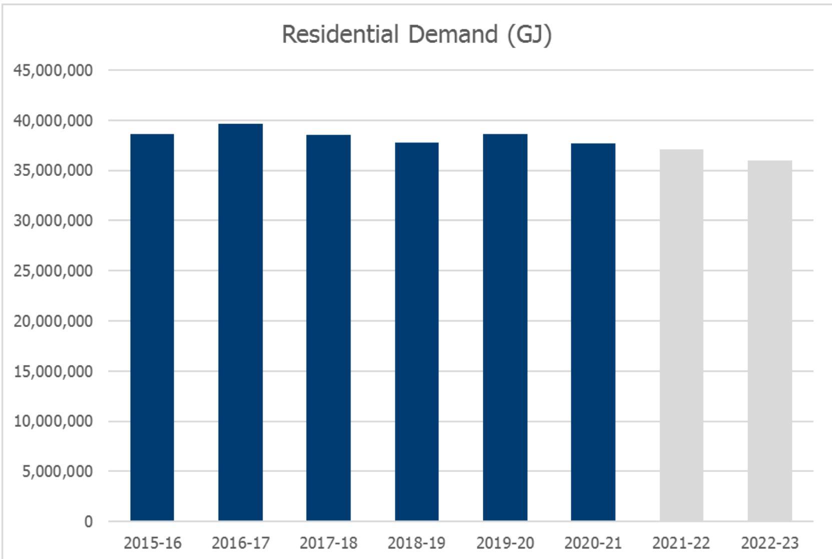


Figure 8.5: Total Demand



The Victorian Government's *Gas Substitution Roadmap* consultation paper examines pathways towards net zero emissions by 2050 in Victoria. Significant funding of around $1.6 billion has been earmarked to accelerate the transition to clean energy including to:

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

The Roadmap may impact on our demand forecast. We will review the release of the roadmap in 2022 and incorporate it into our Final Plan to the extent possible. When there is Victorian Government policy released, this will be incorporated into our forecasts.

The trend in consumption per connection has been affected by the COVID-19 lockdowns in Victoria throughout 2020 and 2021. As noted above, 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 Melbourne, more customers at home meant a higher utilisation of space heating and potentially a higher prevalence of cooking at home. This increased gas demand in 2020 and 2021 and has therefore been excluded from the trend. This approach is consistent with the approach accepted by the AER in its Final Decision for our South Australian natural gas distribution network where natural gas demand was also affected by COVID.

Forecast for the six-month extension period

The forecast of demand for the period 1 January 2023 to 30 June 2023 is necessary to determine any under or over recovery of tariff revenue relative to the allowed building block revenue. Any forecast under or over recovery of tariff revenue will be adjusted for in the next five-year AA period.

To determine the forecast of demand for the six-month period, we have used Core Energy's forecast for calendar year 2023 by averaging its forecasts for financial years 2022/23 and 2023/24. A split was then applied to determine the forecast for the first half of 2023 during the six-month extension period. This assessment of first half demand was completed separately for both the residential and commercial segments and applied to determine a first half forecast. The first half residential split of demand was 41% whilst the commercial split was 44%.

Customer numbers were also determined with reference to the Core Energy forecast of customer numbers with a view to creating a proxy 31 March 2022 view. This is because, for the purposes of the Post Tax Revenue Model, customer numbers are required to be a forecast at the midpoint of the relevant period. Since the six-month period is from January to June 2023, 31 March 2022 is the midpoint of the relevant period.

Total residential demand

In addition to COVID-19 impacts, the nearer term objectives of the *Gas Substitution Roadmap* include the reduction of carbon emissions relative to 2005 levels of between 28% - 33% by 2025 and 45% to 50% by 2030.

The Victorian Government expects this combination of initiatives to reduce gas consumption in Victoria by nine percent by 2025[8], 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 of natural gas and what it means for our networks in our Draft Plan for the next AA period.

Overall, the demand for gas by our residential customers in the next AA period is expected to fall by 2.4% per year. We still expect residential gas demand to remain high in Victoria and far higher than in any other state.

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

8.2.3 Commercial demand forecast

Like residential demand, Core Energy's commercial demand forecast is calculated by multiplying the forecast number of commercial connections by forecast consumption per commercial connection.

Commercial connections

In the next AA period, Core Energy is projecting the number of commercial connections (net of disconnections) will decline by 1.4% per year.

Consumption per connection

The average consumption per commercial connection is forecast to increase over the next AA period reflecting the long-term trend.

The lockdowns in Melbourne due to COVID-19 reduced consumption in the Commercial segment during 2020 and 2021 because many businesses were forced to shut down, either temporarily or permanently.

As with the residential forecast, COVID-19 distorted gas demand and hence those years affected by the pandemic have been excluded from the trend.

Consumption per commercial customer is forecast to increase by 2.1% per year over the next AA period.

Total Commercial demand

The total demand for gas from commercial customers is expected to rise by 0.6% per year over the next AA period.

Figure 8.6: Commercial connections forecast

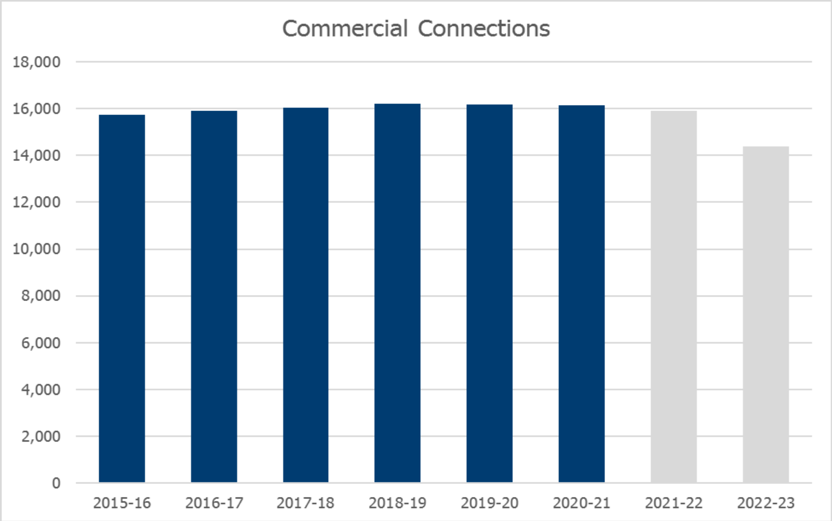


Figure 8.7: Commercial Consumption per Connection

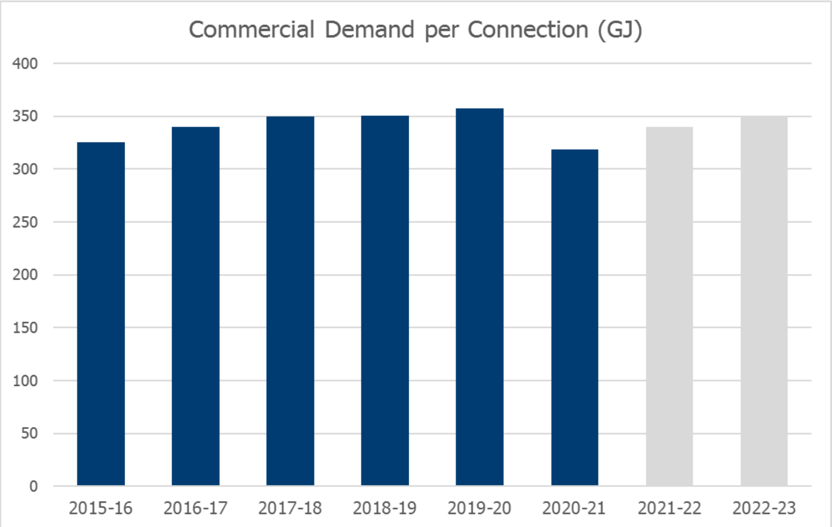
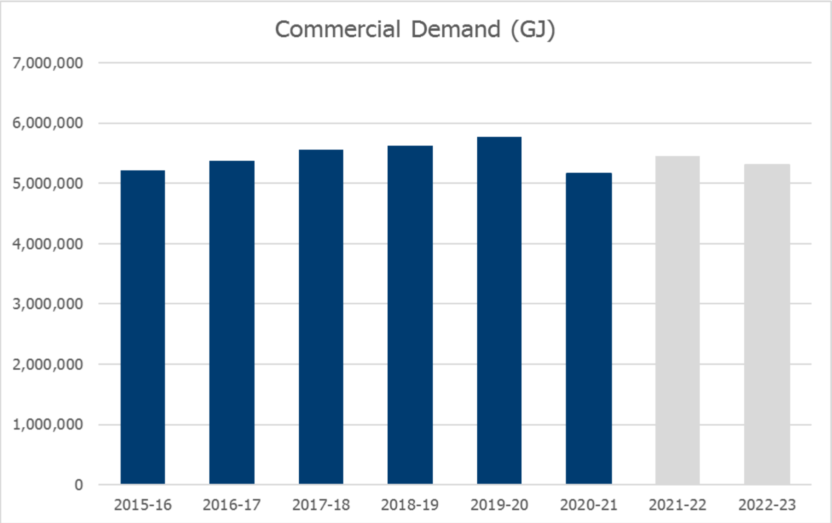


Figure 8.8: Total Commercial Demand



8.3 Industrial demand

8.3.1 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 on a day (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)).

The connections forecast for industrial customers has been developed having regard to historic growth estimates and information on known new connections and disconnections.

8.3.2 Industrial demand forecast

Industrial MHQ is forecast to increase by 0.5% per annum over the next AA period. Our forecast for the six month extension period incorporates the forecast increase in industrial demand between 2020/21 and 2023/24 (see Figure 8.9).

Industrial connections are forecast to stay constant over the next AA period (see Figure 8.10).

Figure 8.9: Industrial MHQ

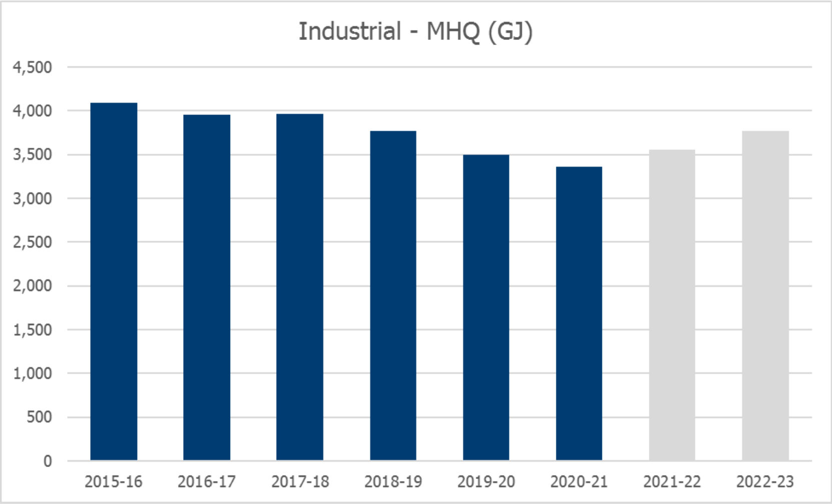
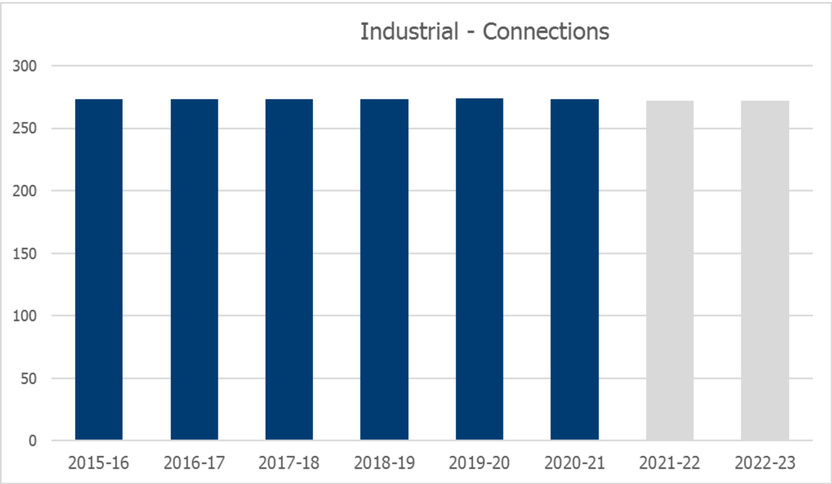


Figure 8.10: Industrial Connections



As the forecast for the industrial segment is based on required capacity there was no need to determine a percentage for the first half of the year as was required for the residential and commercial segments.

8.4 Summary

Table 8.1 provides a summary of our demand forecasts for the six month extension period compared to forecast demand for the calendar year 2023.

Table 8.1: Summary of demand forecast

	2023	H1 2023
Residential demand		
Connections (no.)	697,545	697,545
Demand (TJ)	35,299	14,135
Commercial demand		
Connections (no.)	14,724	14,724
Demand (TJ)	5,061	2,166
Industrial Demand		
Connections (no.)	272	272
MDQ (TJ)	3,673	3,673

9 Revenue and Pricing

This chapter sets out the total revenue and proposed prices to apply to the six month extension period, and the true up required in the next AA period to adjust for any forecast under or over recovery.

IN THIS CHAPTER:

- **We propose to adjust 2022 Multinet network prices for inflation on 1 January 2023.**
- **A revenue adjustment to the next AA period of approximately positive $6 million will be made to ensure both customers and MGN are neutral to the extension of the current AA period by six months to 30 June 2023.**

Our costs are referred to as 'building blocks' and are summed to determine total allowed revenue in the six-month extension period.

We recover our costs through the prices (or tariffs) that we charge retailers for providing reference services.

9.1 Regulatory framework

We are required to determine total revenue for the six month extension 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.

The Order requires the AER to determine a building block revenue and tariff revenue for the six month extension period, with inflation to be applied to tariffs for the six month period. Any forecast over or under recovery of tariff revenue must then be adjusted for in the next AA period.

9.2 Revenue

This Variation Proposal outlines the basis of all the relevant building blocks that are used to determine building block total revenue. The building block total revenue with and without the cost of providing Ancillary Reference Services (ARS) is provided in Table 9.1.

Table 9.1: Building Block Total Revenue, January to June 2023 ($nominal, million)

	H1 2023
Return on Capital	32.5
Return of Capital	14.9
Opex	45.4
Incentive Mechanism	0.0
Cost of Tax	2.8
Building Block Total Revenue (including ARS)	**95.5**
Less ARS	1.4
Building Block Total Revenue (excluding ARS)	**94.2**

Note: Totals may not add due to rounding

Our building block revenue is recovered through the prices we charge retailers for providing residential, commercial and industrial haulage services and Ancillary Reference Services.

Tariff revenue is determined from the demand forecast (discussed in Chapter 8 above) and price. Any forecast over or under recovery must then be adjusted for in the next AA period.

9.3 Prices

As already noted, we recover our revenue through the prices that we charge retailers for providing reference services.

For the six-month extension period, we have proposed to apply 2022 tariffs indexed for inflation. The inflation of 3.75% is taken from the Reserve Bank of Australia's (RBA) Statement of Monetary Policy (SoMP), and reflects its expectations for inflation for the June 2022 quarter, which in turn will need to be updated for actual CPI when it becomes available. Use of the June quarter is consistent with what would be applied in an annual tariff variation, and that applied within the Roll Forward Model.

There have been no changes to the form of revenue control, pricing or tariff structures that apply in the current AA period.

9.4 Revenue adjustment in the next AA period

Table 9.2 compares the expected revenue we will recover through these prices (price multiplied by forecast demand for the six-month period) with the required building block revenue for the six month extension period.

Table 9.2: Revenue adjustment in the next AA period ($nominal, million)

	H1 2023
Building Block Total Revenue (A)	94.2
Forecast Tariff Revenue (B)	91.6
ARS Adjustment	-0.7
Revenue adjustment (A-B+C)	**2.0**

Note: Totals may not add due to rounding

The forecast true up of $2 million will be added to our proposed building block revenue in the 2023/24 to 2027/28 AA period.

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	MGN	Multinet Gas Networks
ARENA	Australian Renewable Energy Agency	MRP	Market Risk Premium
ARS	Ancillary Reference Service	Next AA period	2023/24 to 2027/28
capex	Capital Expenditure	NGL	National Gas Law
CBD	Central Business District	NGR	National Gas Rules
Current AA period	2018 to 2022	opex	Operating Expenditure
DBP	Dampier Bunbury Pipeline	RBA	Reserve Bank of Australia
DRP	Debt Risk Premium	SL CAPM	Sharpe-Lintner Capital Asset Pricing Model
EBSS	Efficiency Benefit Sharing Scheme	TAB	Tax Asset Base
EDD	Effective Degree Day	TJ	Terajoule/s
GJ	Gigajoule/s		

List of Attachments

1.1	Relevant Regulatory Framework
1.2	Confidentiality Claims
1.3	Post Tax Revenue Model
1.4	Roll Forward Model
1.5	Depreciation Model
1.6	Six month extension opex
1.7	Six month extension capex
1.8	Nomination of averaging periods

Feedback

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