July 2016

Draft Plan

Five year plan for our Victorian and Albury natural gas distribution networks

We are Australian Gas Networks, one of Australia's largest natural gas distribution companies.

Our Vision is to become the leading gas distributor in Australia. We will achieve this by delivering for our customers, being a good employer and being sustainably cost-efficient.

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Foreword from the CEO

I am delighted to present our Draft Plan for our natural gas distribution networks in Victoria and Albury for the five-year period commencing 1 January 2018. Our plan delivers continuous improvement on our already high service levels, an 11% upfront cut in distribution prices (before inflation), reduced operating and capital expenditure, and lower financing costs in line with recent decisions by the Australian Energy Regulator (AER).

Australian Gas Networks Limited is one of Australia's largest natural gas distribution companies, serving around 1.2 million customers across most Australian states and territories. In Victoria and Albury we deliver natural gas to around 650,000 customers across central and northern Melbourne, north to Shepparton, Wodonga and Albury in New South Wales, east to Warragul, Traralgon and Bairnsdale and south east to the Mornington Peninsula.

We have delivered strong performance for our Victorian and Albury customers over the 2013 to 2017 period, and importantly, we have met our leak management targets. We have connected over 16,000 new customers to natural gas each year and are on track to deliver 100% (or 696 kilometres) of our low pressure mains replacement program.

We intend to improve on our strong safety performance over the 2018 to 2022 period. We are proposing to replace a further 307 kilometres of old mains, which includes 25 kilometres of mains in the centre of Melbourne. This will complete the replacement of old metal mains in the Victorian and Albury networks. This program is the key driver for ensuring ongoing public safety and network reliability.

Melbourne and Victoria are some of the fastest growing areas in Australia and AGN is proud to support this growth. Over the 2018 to 2022 period, we expect to connect 14,000 new customers to natural gas each year. Customer growth spreads the benefits of gas and lowers prices to existing customers by spreading our mostly fixed costs over a larger customer base.

We are very conscious that the cost of living, including utility bills, is a major concern for many people in Victoria. Gas distribution prices make up around one third of the average domestic retail gas bill, so we have a role to play in the affordability challenge. I am therefore pleased to deliver an 11% upfront price cut (before inflation), with modest annual increases thereafter to match our growing asset base.

Natural gas remains a highly cost-effective and clean domestic fuel compared to electricity. In Victoria most electricity is produced from coal, and using natural gas in the home produces around one third of the carbon dioxide emissions of mains electricity, meaning that gas is cleaner as well as cheaper than electricity.

Our plan is based on the considerable experience of AGN and our operating partner, APA Asset Management. It also reflects feedback from stakeholders, including our Reference Groups and the outcomes from our customer focus groups over the last six months. I would like to take this opportunity to thank the staff of AGN, APA Asset Management, our Reference Groups and those customers and stakeholders that have already informed our proposal.

Overall, we are proposing to continuously improve our strong safety, reliability and customer service levels, cut distribution prices on 1 January 2018 and deliver lower costs. We are confident that our plans for 2018 to 2022 are in the long term interests of our Victorian and Albury customers. We encourage stakeholders to provide feedback on our Draft Plan so that this can be reflected in our final plan that we will submit to the AER at the end of this year.

Ben Wilson

Chief Executive Officer, Australian Gas Networks

Purpose of the Draft Plan

This Draft Plan sets out our plans for our Victorian and Albury natural gas distribution networks for the five year period commencing 1 January 2018. Our Draft Plan, which is a new initiative, is an important part of our stakeholder engagement program. It will inform our final Access Arrangement (AA) Proposal, which we are required to submit to the Australian Energy Regulator by 1 January 2017.

Developing and implementing an effective stakeholder engagement program is key to achieving our aim of submitting a plan that delivers for our customers and is capable of being accepted by the Australian Energy Regulator.

This Draft Plan outlines the feedback we have so far received from stakeholders and our preliminary views on the activities and expenditure we propose to undertake during the next (2018 to 2022) AA period. We also provide an indication of the likely movement in the prices that we will charge retailers for the provision of natural gas distribution services (we will provide the actual prices as part of our AA Proposal).

Our Draft Plan does not discuss the (non-price) terms and conditions for the supply of natural gas. These terms are contractual matters largely between AGN and retailers, who enter into a contract directly with AGN for the supply of natural gas to customers in Victoria and Albury. We are currently in the process of engaging with our Retailer Reference Group (RRG) on our terms and conditions.

Our Draft Plan therefore provides stakeholders with an important opportunity to provide feedback on our plans for our consideration as we develop our AA Proposal. AGN will consider any feedback received on the Draft Plan, and through our stakeholder engagement program more generally, before finalising our AA Proposal.

We therefore encourage our customers and stakeholders to provide feedback on this Draft Plan. To guide you, we have highlighted key questions/issues that we are seeking your feedback on at the end of each section. This should not however restrict the feedback that you provide. We are open to your feedback on any matter relating to our prices and services that we intend to provide to our customers over the next AA period.

Please refer to the Next Steps section for further details on how to provide your feedback (submissions close on 16 August 2016).

We look forward to receiving your comments.

Our Vision is to be the leading natural gas distributor in Australia.

Australian Gas Networks

Lower prices

11%

Cut in prices on 1 January 2018

Improved Service

>90%

Of emergency calls answered within 10 seconds.

Continuous improvement in safety, reliability and customer service.

Lower Costs

$36m

Cut in expenditure compared to actual expenditure incurred in the current AA Period.

Ensuring we are sustainably cost-efficient.

New Customers

+14,000

New customers connecting to our network each year.

Better access to gas, contributing to lower carbon emissions.

Lower prices, lower costs, continuous service improvements.

1. Plan Highlights

Australian Gas Networks Limited (AGN) is one of the largest natural gas distributors in Australia. We deliver natural gas to around 650,000 customers connected to our Victorian and Albury networks. We are required to update the prices we charge for providing natural gas distribution services every five years.

Our prices for the next (2018 to 2022) Access Arrangement (AA) period will be set out in our AA Proposal, which we are required to submit to the AER for approval by 1 January 2017. Our overarching objective is to submit an AA Proposal that delivers for customers, is underpinned by effective stakeholder engagement and is capable of being accepted by the AER.

This Draft Plan is a key part of our stakeholder engagement program. This plan outlines the feedback we have so far received from stakeholders, the key activities and expenditure we intend to undertake and the prices we propose to charge retailers over the next AA period. We will consider feedback on this plan before we finalise our AA proposal by the end of this year.

This section summarises what we have delivered over the current AA period and what we propose to deliver over the next AA period.

What We Have Delivered

We have met the key safety standards set for the business and delivered the major outputs set by the AER for the current AA period. Our key achievements include:

- Providing high reliability of supply to our customers, averaging only 18 interruptions affecting five or more customers each year;
- Delivering and implementing our customer satisfaction surveys, which for the first time provide the business with direct information to understand and improve our customer service;
- Designing and implementing our broader stakeholder engagement program, which assists the business to ensure that we are promoting the long term interests of our customers;
- Facilitating more than 16,000 new customer connections to our Victorian and Albury networks each year, including in new areas such as Merrifield, Koo Wee Rup and Wandong-Heathcote Junction;
- Planning to deliver the full low pressure mains replacement program approved by the AER for the current AA period (696 kilometres);
- Achieving leading productivity performance relative to other gas distributors operating in Australia; and
- Ensuring the ongoing safety of our employees, with only 1.6 lost time injuries per million hours worked.

What We Will Deliver

We are proposing to continually build on this strong performance over the next AA period. We are proposing to:

- Deliver an upfront 11% reduction in distribution prices for Victoria and Albury in real (before inflation) terms, with prices lower on average in real terms over the next AA period compared to current prices;
- Continue to deliver leading productivity performance by lowering expenditure levels;

- Deliver a 3% (or $10 million) reduction in operating expenditure (opex) compared to current levels, despite increasing customer numbers and the delivery of an expanded marketing program;
- Deliver a 5% (or $26 million) reduction in capital expenditure (capex) compared to current levels, whilst providing for the completion of our low pressure mains replacement program and national Information Technology (IT) program;
- Improve public safety through the completion of our mains replacement program and maintain reliability through several key network expansion initiatives, which is consistent with the outcomes of our stakeholder engagement program;
- Facilitate an additional 14,000 new customer connections to our networks each year, which assists in delivering lower prices to existing customers; and
- Improve and strengthen the incentives for the business to deliver lower costs, improved network performance and customer service.

Next Steps

We encourage stakeholders to provide feedback on this Draft Plan. We are open to your feedback on any and all topics relating to our prices and the services that we intend to provide over the next AA period. Your feedback is a key part of assisting AGN to achieve its objective of submitting an AA Proposal that delivers for customers and is capable of being accepted by the AER.

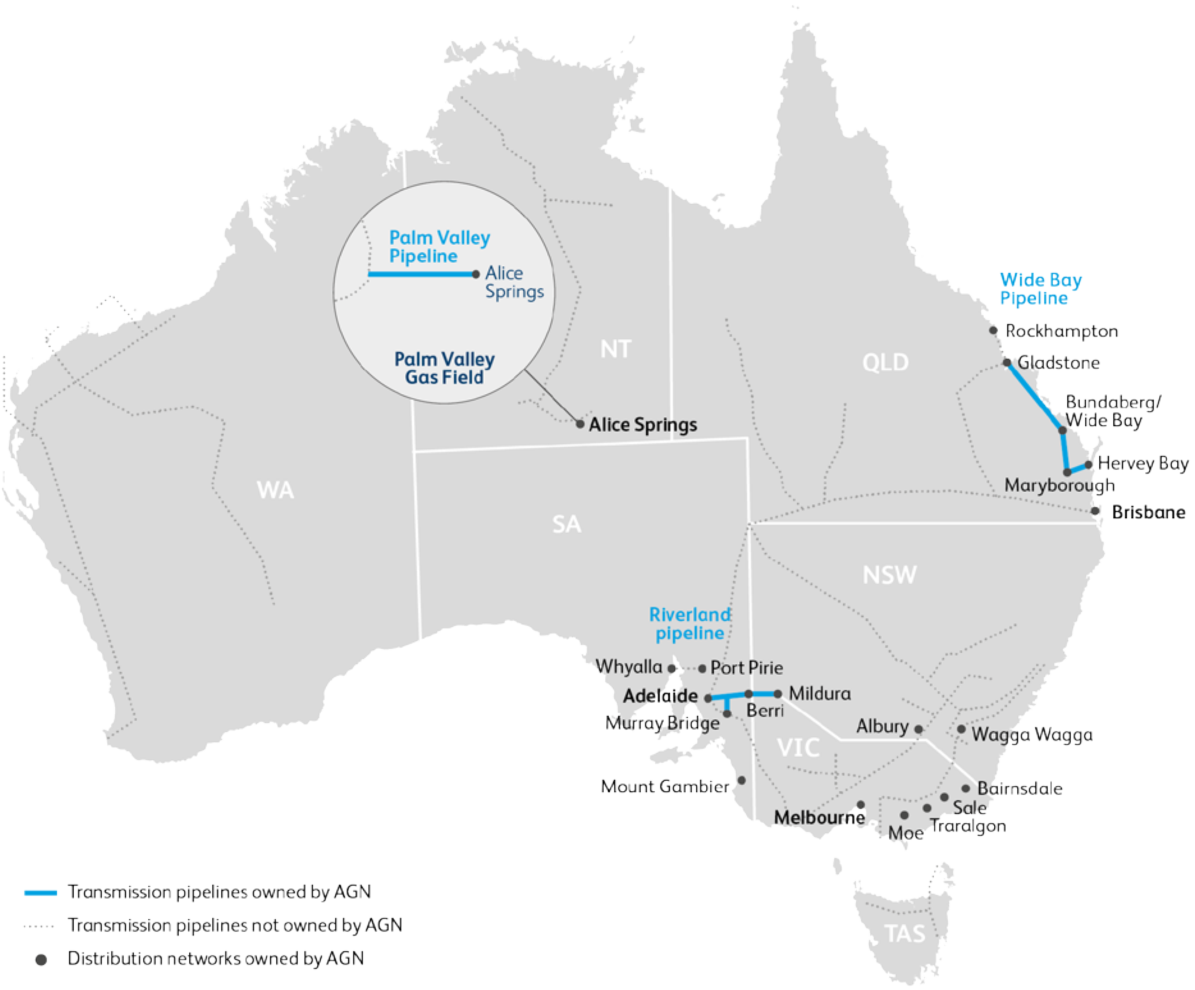
The Next Steps section of this plan provides details on how you can provide your feedback on this Draft Plan to AGN.

2. About Our Business

2.1. Introduction

AGN is one of the leading natural gas distribution businesses in Australia, serving around 1.2 million domestic, small business and large industrial customers. AGN owns over 23,000 kilometres of natural gas distribution networks and 1,100 kilometres of transmission pipelines in Victoria, New South Wales, South Australia, Queensland and the Northern Territory (see Figure 2.1). AGN is owned by the Cheung Kong Hutchison Group of companies based in Hong Kong[1].

Figure 2.1: Map of AGN's Networks



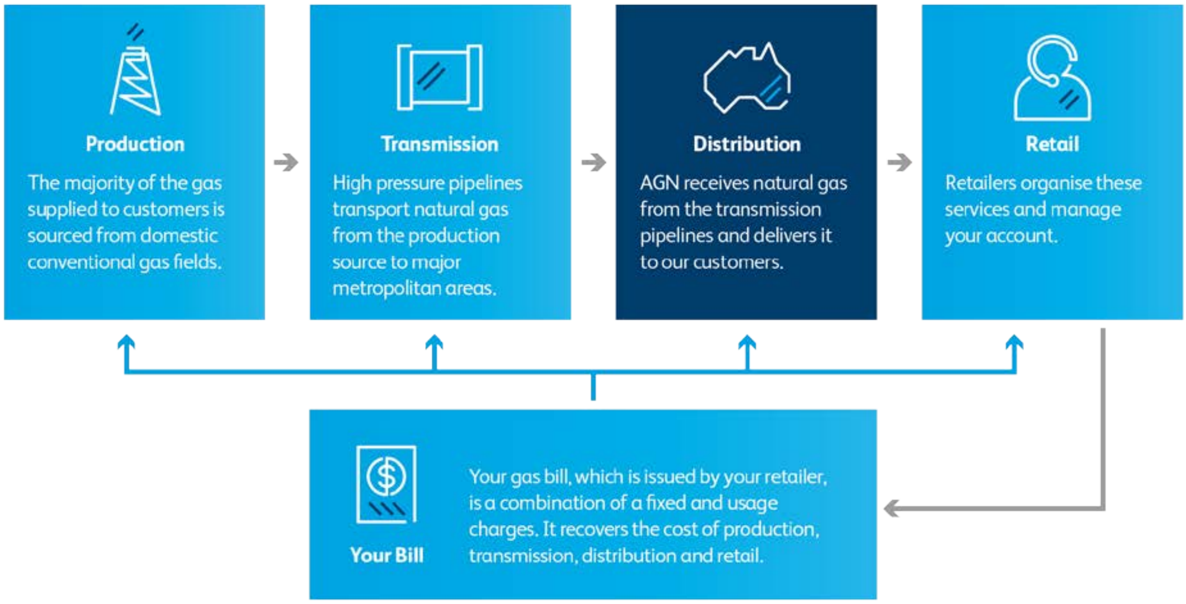
[1] The Cheung Kong Hutchison Group acquired Envestra Limited in August 2014 and subsequently changed the company's name to Australian Gas Networks Limited. Prior to the ownership change, and since its inception in 1997, Envestra Limited was a publicly listed company on the Australian Securities Exchange (ASX). After the acquisition by the Cheung Kong Hutchison Group, AGN was delisted from the ASX in October 2014.

2.2. Our Role

Our role in providing natural gas to customers is illustrated in Figure 2.2. After production, natural gas travels to customers through a high pressure transmission system (usually not owned by AGN) and a distribution network (owned by AGN). We own the distribution network in metropolitan areas that delivers (or transports) gas directly to the customer. We also own and read the meters.

Retailers organise the purchase of natural gas from producers and the transport of gas through the transmission and distribution networks. Retailers are also responsible for directly managing the customer account, and as such, are the primary customer reference point in relation to the supply of natural gas. Retailers charge customers for the cost of providing all of the services required to supply natural gas.

Figure 2.2: Natural Gas Supply Chain



2.3. Our Vision: To Be the Leading Natural Gas Distributor in Australia

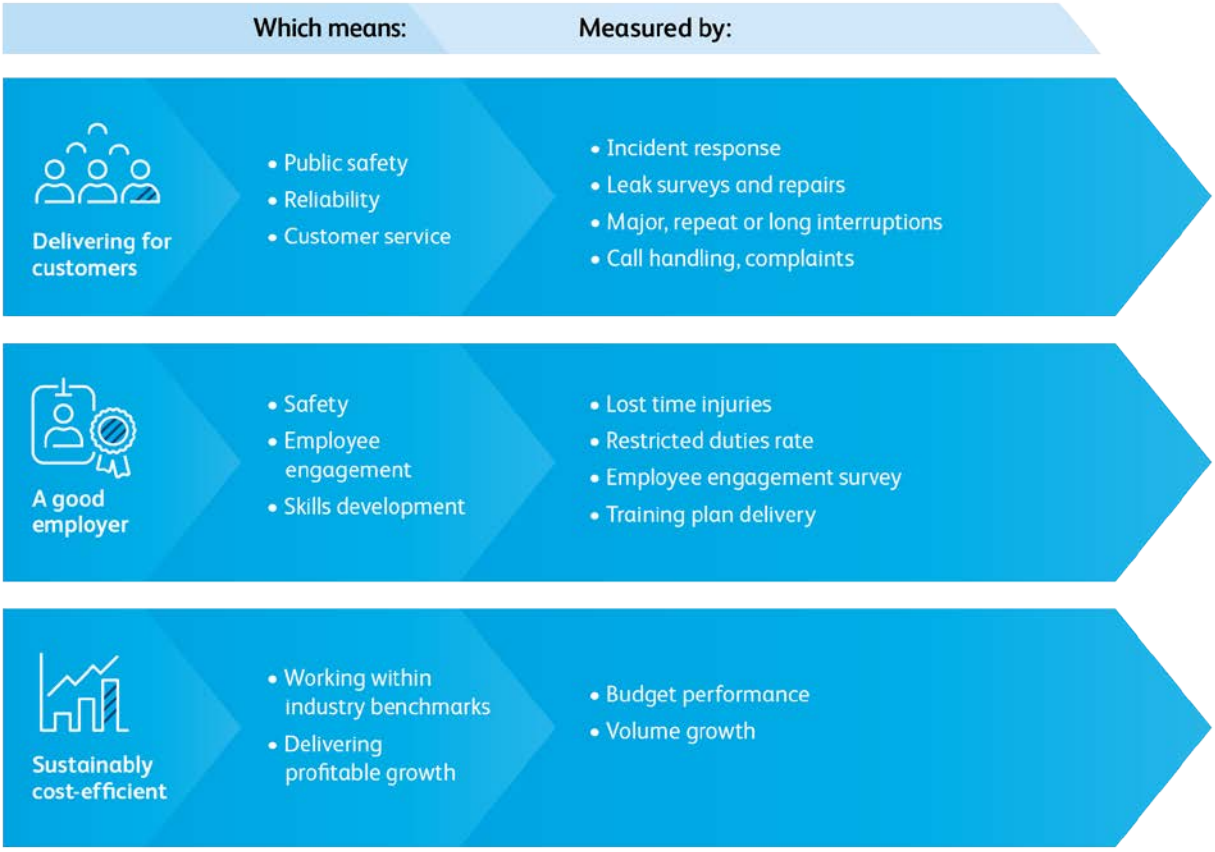
Our aim is to be the leading natural gas distributor in Australia. Our definition of leading is to achieve top quartile performance compared with other Australian natural gas distributors across all of our key targets. Our Vision sets out the following three key objectives that we consider are consistent with being the leading natural gas distributor in Australia:

- *Delivering for Customers* – which means ensuring public safety and the provision of high levels of network reliability and customer service;
- *A Good Employer* – which means ensuring the safety of our employees (including contractors), ensuring employees are motivated to achieve our Vision and receive appropriate training; and
- *Sustainably Cost-Efficient* – which means undertaking the required scope/volume of work within the benchmarks set by the AER while growing the network in a prudent and efficient manner.

We communicate our Vision to all key stakeholders, such as employees/contractors, governments, regulators, investors and our customers. Importantly, all of the objectives set out in our Vision can be measured, including in most instances against the performance of our industry peers. We also publicly report on our performance under our Vision and use it to drive ongoing improvements in service and operational performance[2].

Figure 2.3 details our Vision and how we intend to measure our performance. Our performance over the current AA period against the Vision is discussed in the remainder of this section.

Figure 2.3: Our Vision Statement



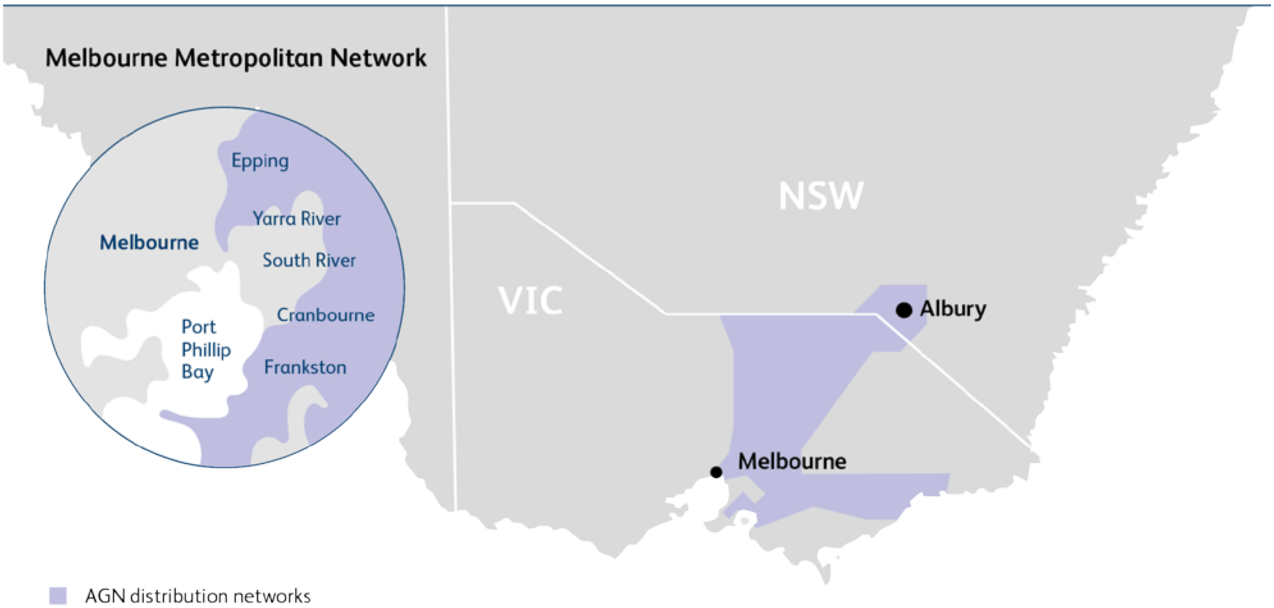
2.4. Description of the Networks

Figure 2.4 describes the location and key features of our Victorian and Albury networks. Our networks supply close to 650,000 customers through around 11,000 kilometres of predominantly distribution mains. Our networks are located in the city of Melbourne, inner and outer northern suburbs of Melbourne, outer eastern and southern areas of Melbourne, surrounding regional areas (including through to the Mornington Peninsula) and Albury.

The two networks are interconnected, with the Albury network fed from the northern zone of the Victorian network.

[2] Our 2015 Annual Review can be accessed at http://www.australiangasnetworks.com.au/our-business/annual-reports/annual-reports/.

Figure 2.4: Area Covered by AGN's Victorian and Albury Networks



	VIC	NSW
Regulated metropolitan networks	Melbourne	n/a
Regulated regional networks	Shepparton, Wangaratta, Wodonga, Moe, Morwell, Traralgon, Sale, Bainsdale	Albury
Length of mains (km)*	10,461	638
Number of customers*	626,106	21,936
Volume transported for 2015 (TJ)	55,843	2,759

* As of 31 December 2015

Note: Regulated networks only.

2.5. Outsourcing Arrangement

Our assets are operated by APA Asset Management (APA) under a long term Operating and Management Agreement (OMA). The services provided under the OMA include:

- operating and maintaining each network;
- planning, designing and constructing network extensions;
- preparing and settling with AGN the budget for each financial year;
- providing AGN with regular information on financial and other management issues; and
- reading meters and billing retailers.

2.6. Regulatory Framework

We operate our networks in accordance with the National Gas Law (NGL), National Gas Rules (NGR) and various state-based operating guidelines. The AER monitors our compliance with the NGL and NGR. The overarching requirement of the NGL is the National Gas Objective (NGO), which requires AGN to:

> *"promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply".*[3]

To achieve the NGO we must:

- ensure prices are consistent with the lowest sustainable (long term efficient) cost;
- deliver service levels that reflect what our customers want and are willing to pay for;
- provide services in a safe and reliable manner; and
- adapt prices and service levels to changing market conditions.

3 National Gas (South Australia) Act 2008, s23.

3. Our Track Record

3.1. Introduction

This section describes what we have delivered over the current AA period against the targets set out in our Vision.

3.2. What We Have Delivered

Figure 3.1 summarises our performance over the current AA period against the targets set out in our Vision. Overall, we have met the key safety standards set for the business and delivered the major outputs set by the AER for the current AA period.

Figure 3.1: What We Have Delivered over the Current AA Period

	Which means:	2013 – 2017 Actual/Estimates:
Delivering for customers	• Public safety • Reliability • Customer service	• Emergency calls: 92% answered in 10 seconds • Customer calls: 80% answered in 30 seconds • Leaks: 95% attended in two hours • Average 18 major interruptions per annum* • Stakeholder engagement program and customer service surveys implemented • Approximately 16,000 new connections per annum
A good employer	• Safety • Employee engagement • Skills development	• Less than 2 Lost Time Injuries (LTIs) per annum • Lost Time Injury Frequency Rate (LTIFR) of 1.6 per annum • 100% compliance regarding employee refresher training
Sustainably cost-efficient	• Working within industry benchmarks • Delivering profitable growth	• On track to deliver 100% mains replacement program • Delivered network extension to Merrifield, Koo Wee Rup and Wandong-Heathcote Junction • Spending within the AER benchmarks for operating and capital expenditure

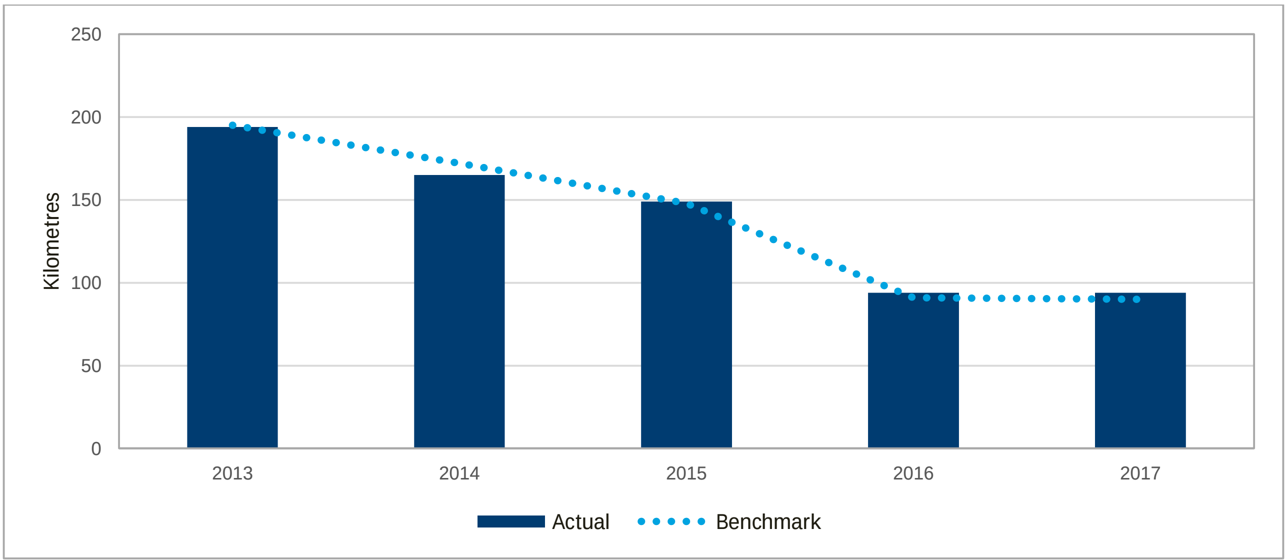
* Major is defined as an interruption affecting five or more customers
# LTIFR is the number of lost time injuries over a year relative to the total number of hours worked in the year

Key achievements over the current AA period include the following:

- *Delivering for Customers* – we have delivered natural gas in a safe manner to our customers, and in doing so, complied with all relevant safety obligations/requirements set for the business. Typically, our customers experience only one supply interruption every 40 years. We have also achieved strong growth in customer numbers, connecting over 16,000 customers to the networks each year;
- *A Good Employer* – we have achieved industry best practice employee safety levels over the current AA period and provided all necessary training to our employees/contractors; and
- *Sustainably Cost-Efficient* – our actual opex and capex will be below the benchmarks set by the AER in the current AA period by 13% and 2% respectively, generating savings for customers in the next AA period. We have also maintained our leading productivity performance across the industry (see Section 3.2.1).

Importantly, the estimated reduction in capex has not come at the expense of the delivery of our key asset management programs. For example, AGN intends to deliver the benchmark volume of mains replacement over the current AA period, as shown in Figure 3.2. AGN is forecasting to complete the mains replacement program over the next AA period (see Section 8). Our mains replacement program is key to ensuring the ongoing safe supply of natural gas to our customers.

Figure 3.2: Delivery of our Mains Replacement Program



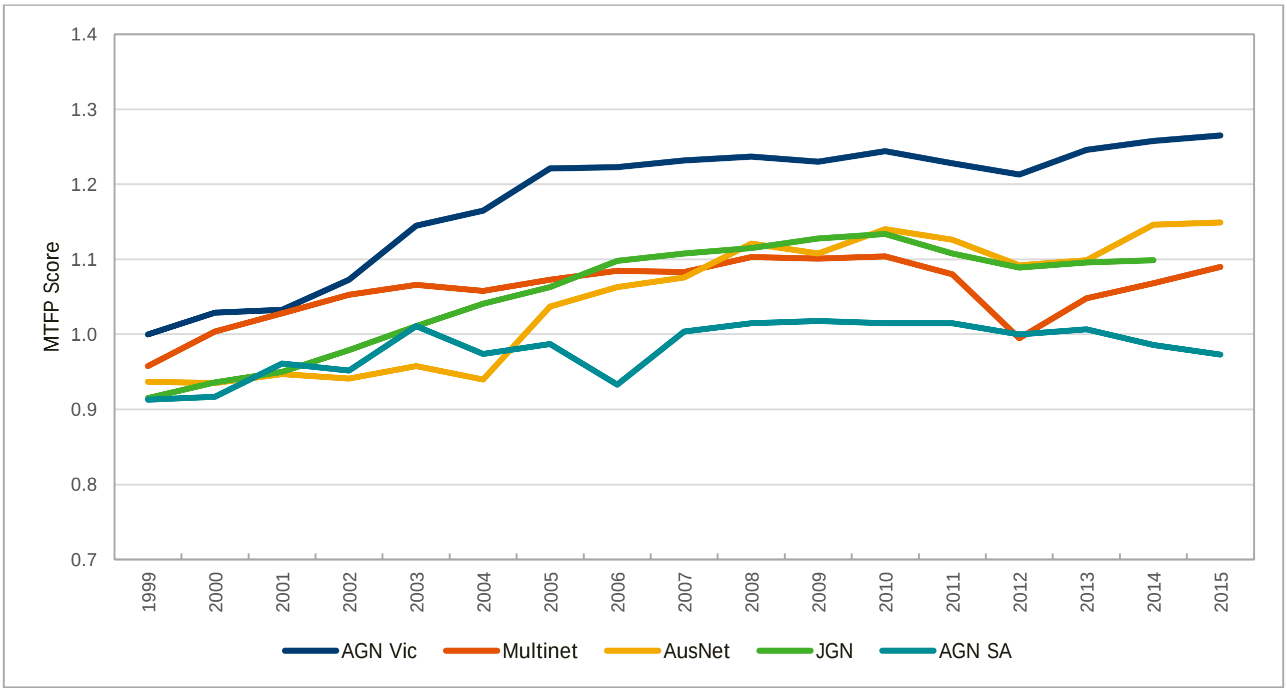
3.2.1. AGN has Delivered Leading Productivity Performance

AGN has engaged an independent expert to undertake an analysis of our productivity performance relative to other Australian gas distributors. The key measure of relative productivity is multilateral total factor productivity (MTFP), which measures the absolute (or overall) productivity levels across different distributors (where the productivity for each distributor is measured as the ratio of total outputs relative to total inputs used).

The analysis compares the productivity performance of our Victorian network (AGN Vic) with the two other Victorian gas distributors (AusNet Services and MultiNet), Jemena Gas Networks (JGN) in New South Wales and our South Australian (AGN SA) network. The comparative analysis was undertaken for the 1999 to 2015 period, which reflects the period for which data was available for the distributors included in the sample.

Figure 3.3 shows the relative MTFP scores for each distributor, where higher MTFP scores imply higher productivity levels. The analysis shows that our Victorian network, represented by the dark blue line, has the highest productivity level of all gas distributors included in the sample. Our productivity levels are around 10% higher than the next most efficient distributor and 16% above the industry average.

Figure 3.3: Economic Insights' MTFP results 1999-2015



3.3. Summary

AGN is one of the leading gas distributors in Australia, with around 1.2 million customers across most states and territories in Australia. We have a clear and measurable Vision: to deliver for customers, to be a good employer and to be sustainably cost-efficient. Our target is to be Australia's leading gas distributor across these measures.

We have delivered strong performance in Victoria and Albury over the current AA period. This includes meeting all key safety targets governing the supply of natural gas, providing high levels of network safety and reliability, providing best practice levels of employee safety and industry leading productivity performance. AGN has delivered the key projects that were funded over the current AA period within the benchmarks that were set by the AER.

We intend to build on this strong performance over the next AA period, as explained in the remainder of this Draft Plan.

4. What we will Deliver

4.1. Introduction

Our Vision is to be the leading natural gas distributor in Australia. As outlined in Section 3, we have delivered against the targets set out in our Vision over the current AA period, including the provision of high levels of community safety, network reliability, customer service and leading productivity performance. We have also delivered the scope of works for the key projects included in the benchmarks set by the AER for the current AA period.

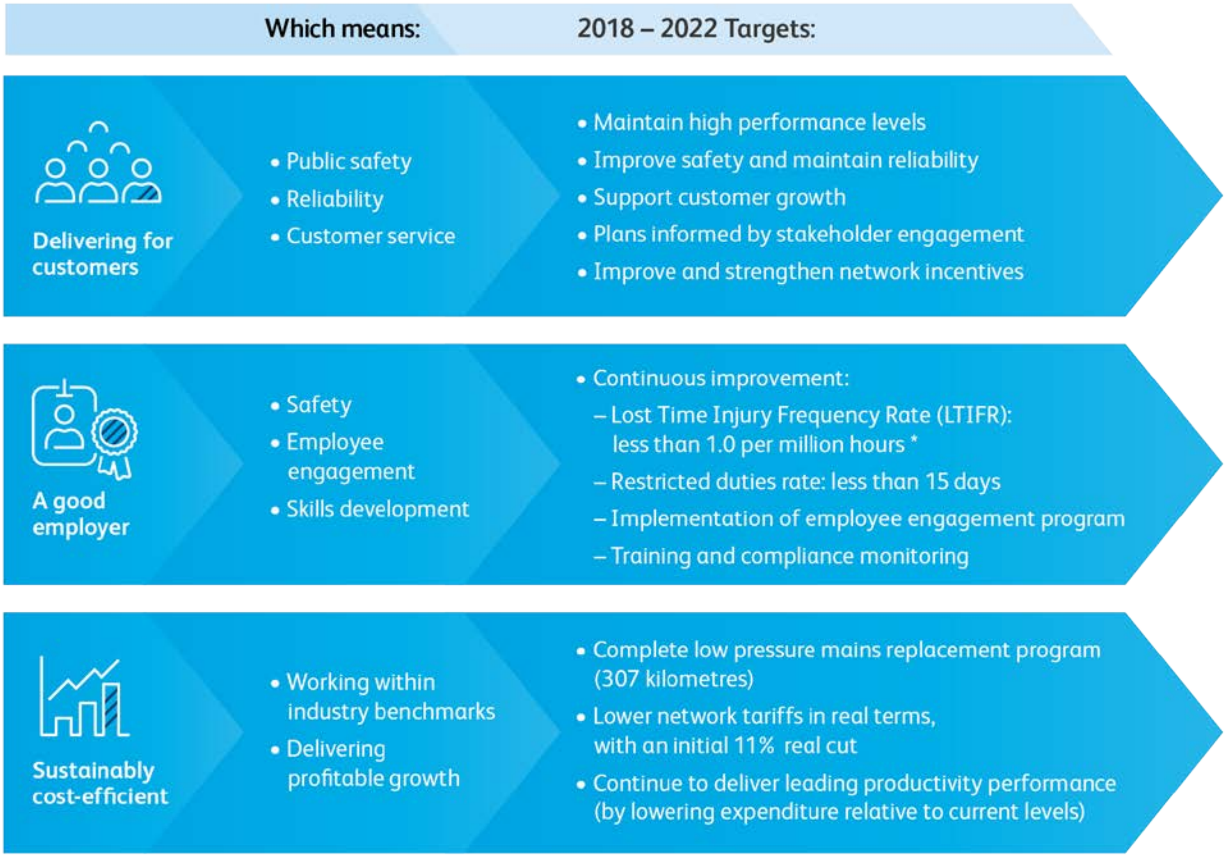
As explained in this section, we plan to continue to deliver high performance levels over the next AA period against our Vision.

4.2. Delivering on our Vision

Figure 4.1 summarises the key deliverables that we intend to provide over the next AA period against the targets set out in our Vision. In particular, AGN intends to:

- deliver an upfront 11% reduction in distribution prices (or tariffs) in real (excluding inflation) terms on 1 January 2018, with prices lower on average in real terms over the next AA period compared to current prices (see Section 13);
- continue to deliver leading productivity performance, including by reducing capex by 5% and opex by 3% compared to the current AA period, collectively delivering a $36 million reduction in our costs (see Sections 3, 4, 7 and 8);
- maintain current levels of reliability and customer service, which is consistent with the feedback received during our stakeholder engagement program (see Sections 5, 7 and 8);
- introduce customer satisfaction measurements as a ‘business-as-usual’ key performance indicator, which will help drive a change in our culture to be a genuinely customer-focused organisation (see Section 12);
- improve the safety of our networks, primarily through the completion of the low pressure mains replacement program, which is also consistent with feedback received during our stakeholder engagement program (see Sections 5 and 8);
- continue to grow our networks, with around 14,000 new customers expected to be connected to our Victorian and Albury networks each year (see Sections 8 and 11);
- drive continuous improvement in employee/contractor safety, undertake regular employee engagement/satisfaction surveys and ensure all employees receive (at least) the training required to efficiently deliver on the requirements of their job (see Section 7); and
- improve and strengthen the incentives for the business to pursue prudent and efficient expenditure and provide incentives to make ongoing improvements in customer service (see Section 12).

Figure 4.1: What We Will Deliver Over the Next AA Period



* LTIFR is the number of lost-time injuries over a year relative to the total number of hours worked in that year

4.3. Delivering for Customers

Delivering for customers means ensuring public safety and providing high levels of network reliability and customer service. AGN considers that the safe and reliable supply of natural gas is the most important driver of business performance. AGN is also focused on providing high levels of customer service, particularly given natural gas is a fuel of choice for most customers.

As outlined in Section 3, AGN has delivered high levels of network reliability and customer service over the current AA period. In summary, in respect of:

- *Public safety* – AGN has complied with the safety requirements set out in our Leakage Management Procedure (which outlines the process for managing natural gas leaks on the network);
- *Reliability* – there has been, on average, only 18 major network interruptions per year; and
- *Customer service* – over 90% of customer calls to our emergency call centre are answered within 10 seconds.

Consistent with stakeholder feedback, we intend to continue to deliver high levels of performance for customers over the next AA period. This will be achieved by:

- ensuring our AA Proposal has been informed by an effective stakeholder engagement program (which is also relevant to meeting our objective of delivering for our customers and submitting a plan that is capable of being accepted by the AER);
- improving the security of supply across our networks, particularly by completing a long term initiative in the outer eastern/southern parts of the network through to the Mornington Peninsula;
- continuing to support network growth, with an average of 14,000 new customer connections to the gas distribution network per year over the next AA period; and
- strengthening the incentives to improve performance through a more comprehensive set of incentive arrangements to apply over the next AA period.

4.4. A Good Employer

Employee safety is a key focus of the business, which is why AGN has incorporated safety targets in our Vision. AGN is targeting an improvement in outcomes relating to employee safety over the next AA period. Specifically, AGN is aiming to reduce the Lost Time Injury Frequency Rate (LTIFR) from 1.6 to less than 1.0 lost time injuries per million hours worked. This will ensure AGN remains at best practice levels of employee safety across the industry.

AGN will also implement and report on the outcomes of our employee engagement program. Central to this is undertaking regular surveys of employees aimed at testing matters such as whether employees are aware of key business targets (including that set out our Vision), motivated to achieve and improve on targets and consider there is appropriate support to achieve their own personal objectives (including through access to training).

Related to this, AGN will routinely monitor over the next AA period whether employees and contractors have received appropriate training for the job they are undertaking for the business.

4.5. Sustainably Cost-Efficient

Being sustainably cost-efficient means delivering the required outputs within industry benchmarks while growing the network in a prudent and efficient manner. The key deliverables over the next AA period under this part of our Vision include:

- continuing to deliver on our mains replacement program, particularly the completion of the low pressure mains replacement program;
- continuing to investigate and support network growth opportunities;
- continuing to deliver leading productivity performance, which will be facilitated through reductions in both capex and opex relative to current levels and passing on to customers the benefits of the cost savings we have made in the current AA period; and
- delivering lower distribution tariffs, on average, in real terms over the next AA period compared to current (2016) tariffs.

4.6. Summary

Our plans for the next AA period have been informed by an effective stakeholder engagement program. Overall, we are proposing to continue to deliver high levels of safety, network reliability, customer service and leading productivity performance at a lower cost than we have over the current AA period. We are proposing to deliver an upfront price cut of 11% on 1 January 2018, with lower average prices in real (before inflation) terms relative to current levels.

Stakeholder Questions

1. Do you have any feedback on our key targets for the next AA period, including whether our targets are consistent with feedback received from our stakeholder engagement program?

5. Stakeholder Engagement

5.1. Introduction

AGN is committed to achieving our objective of providing a plan to the AER that delivers for our customers and is capable of being accepted. As noted in Section 1, our stakeholder engagement program is a key part of achieving this objective. We are therefore aiming to develop a plan that is supported by our key stakeholders, which we consider is also important to demonstrating that our plan promotes the long term interests of our customers.

This section explains our approach to stakeholder engagement and outlines how the program has impacted our plans for the next AA period.

5.2. AGN Reference Groups

A key part of our stakeholder engagement program has been the establishment of the following two Reference Groups:

- *Victorian and Albury Reference Group (VARG)* – which comprises representatives from a broad cross-section of key community stakeholder groups; and
- *Retailer Reference Group (RRG)* – which comprises the retailers operating in Victoria and Albury.

The composition of our two Reference Groups is shown in Figure 5.1. The Reference Groups provide AGN with efficient access to the needs, values, priorities and preferences of a broad cross-section of customers served by our networks.

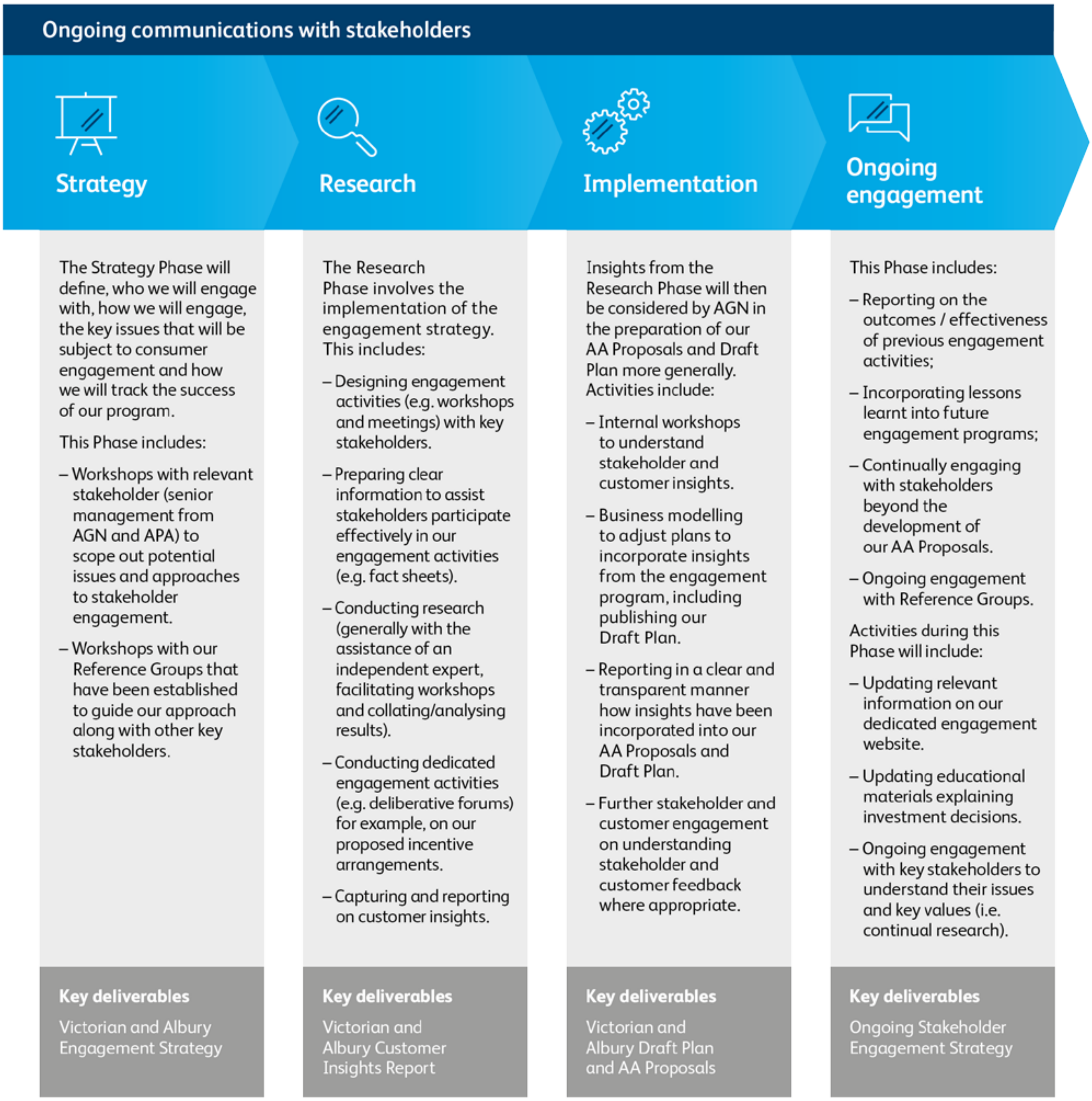
The key role of our Reference Groups is to challenge, guide and review the process of developing and implementing our stakeholder engagement program. Both Reference Groups are involved in all phases of our program (see Section 5.3). AGN intends to engage in further detailed discussions with both of our Reference Groups following the release of this Draft Plan. The outcomes of this engagement will be transparently reported in our AA Proposal.

Figure 5.1: Composition of AGN Reference Groups

5.3. Our Approach to Stakeholder Engagement

Our approach to stakeholder engagement comprises four phases (see Figure 5.2).

Figure 5.2: AGN's Approach to Stakeholder Engagement



The key features of each stage of our engagement program include:

- *Strategy Phase* – which includes the development of our specific stakeholder engagement strategy for Victoria and Albury and our dedicated stakeholder engagement website (which can be accessed at: http://stakeholders.agnl.com.au;

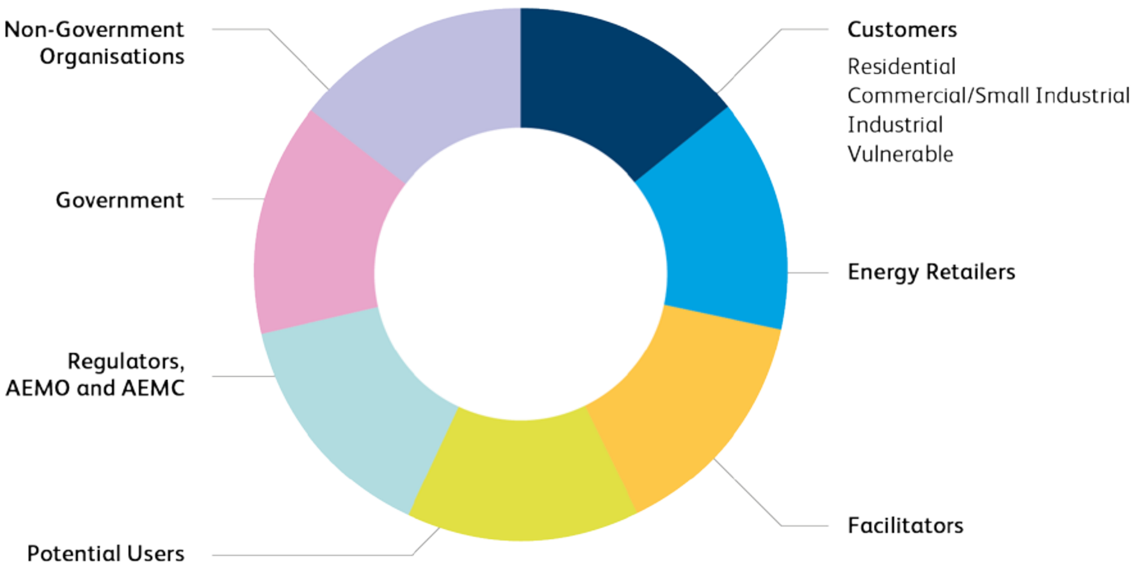
- *Research Phase* – which includes, with the assistance of an independent expert, facilitating customer workshops, holding one-on-one meetings and collating/analysing the key outcomes from our research;
- *Implementation Phase* – internal review of the feedback received during the research phase, development of this Draft Plan (and related engagement activities), culminating in the development of our AA Proposal; and
- *Ongoing Engagement Phase* – a commitment to engage with our stakeholders on an ongoing basis.

The key activities undertaken under each phase are discussed in more detail in the remainder of this section.

5.4. Strategy Phase

The objective of the Strategy Phase was to develop a robust approach to stakeholder engagement for Victoria and Albury. The key steps in this process included identifying our key stakeholder groups, the issues for engagement and the appropriate method for engagement. Figure 5.3 summarises the relevant stakeholder and customer groups included in our engagement program.

Figure 5.3: AGN's Stakeholders and Customers



The key themes for engagement identified in the Strategy Phase include:

- *Customer Experience* – which includes stakeholder awareness of AGN and the appropriate level and channels for communicating with customers (e.g. through our website and/or other digital methods of communication);
- *Network Safety and Reliability* – which includes proposed initiatives that are aimed at maintaining and improving the safety and reliability of the networks;
- *Tariff Structures* – which includes customer preferences on how they would like to be charged for natural gas; and

- *Environmental Commitments and Reporting* – which includes customer expectations with regard to reporting on our environmental commitments.

The Strategy Phase identified a mix of engagement methods to receive feedback from stakeholders on the above matters, including through customer workshops and meetings with our Reference Groups.

5.5. Research Phase

The objective of the Research Phase was to develop a better understanding of stakeholder values. The key output from this process was a report from our independent expert advisor capturing the feedback from a series of customer workshops that were held across our networks.

5.5.1. Customer Workshops

We held two customer workshops in metropolitan Melbourne and four workshops in major regional centres (Albury/Wodonga, Shepparton, Narre Warren and Traralgon). Workshop participants were recruited on the basis of gender, age, household income and concession availability to ensure a representative sample of natural gas customers. Overall, 78 residential and commercial customers attended the workshops.

Deloitte were engaged as an independent expert advisor to assist AGN with the design, participant recruitment and delivery of the workshops. Deloitte also led the facilitation of the workshops while representatives from AGN and APA provided the content relating to the AA Proposal. The workshops were designed to:

- explain the role AGN has in supplying natural gas to customers, including explaining those matters that AGN can and cannot control;
- explain the composition of a typical natural gas retail bill, including our view as to the direction of the distribution component of the retail bill (the part AGN is responsible for);
- understand the views of workshop participants on their natural gas supply, including a discussion on key customer values;
- understand the communication preferences of participants, including whether they would prefer to interact with AGN through traditional existing 'paper' channels and/or through the use of 'digital' channels;
- understand customer preferences for reliability and safety investment options proposed by AGN for the next AA period; and
- facilitate open discussion on key topics, such as the environment and tariff structures.

As part of the South Australian engagement program the Consumer Challenge Panel (CCP) provided feedback that:

> *"......the use of anonymous voting methods is essential in such workshops. Without the benefit of anonymity, participants who are not confident to express a view are easily swayed by the opinions of others in the group"*[4]

AGN was mindful of this feedback and ensured the Victorian and Albury workshops were structured so that all initiatives were subject to anonymous voting. Of the initiatives that were

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[4] AER Consumer Challenge Panel 2015, *"Advice to AER from Consumer Challenge Panel sub-panel 8 regarding Australian Gas Networks' (SA) Access Arrangement 2016-2021 Proposal"*, pg. 5.

supported, customers were asked to rank the supported initiatives in order of importance. The cost impact of each initiative (including the various options) and the total cost of all initiatives was clearly communicated prior to customers independently completing their voting sheet.[5]

5.5.2. Customer Insights Report

The Deloitte Customer Insights Report has been published on our stakeholder engagement website. Deloitte in their report distilled the feedback from the customer workshops into nine customer insights, which are summarised in Table 5.1.

The key feedback included that customers:

- would like to access more information about AGN, including our role in supplying natural gas to customers;
- traditionally considered gas a cost-effective alternative to electricity, but are concerned with recent price increases;
- view gas as a reliable source of energy and value the current standard of reliability;
- are supportive of initiatives that maintain reliability and maintain and improve safety of the network; and
- value the control gained by having their gas bill dependent on usage levels.

[5] Note: The voting sheets and priority lists and an example of the presentation provide at a workshop are available on our dedicated stakeholder engagement website.

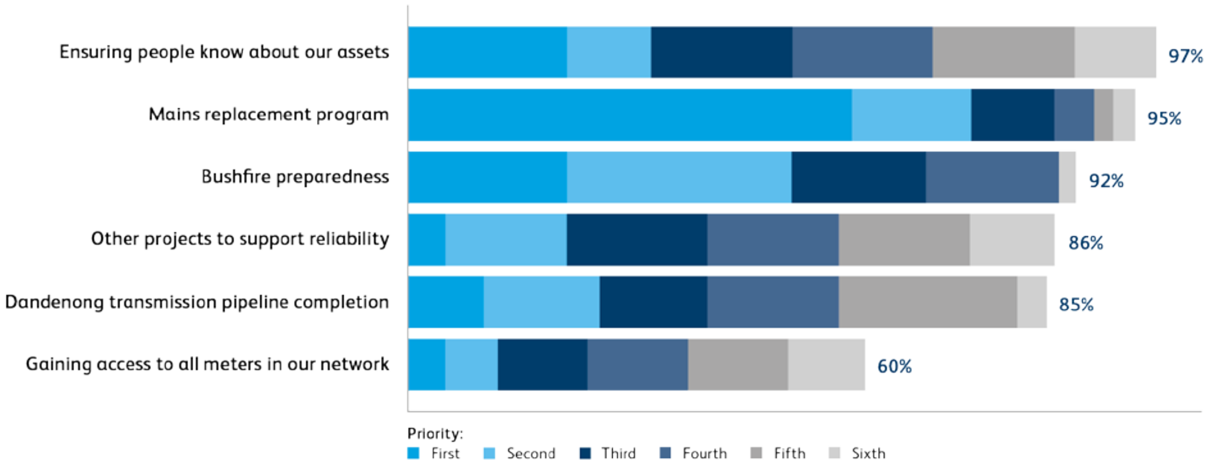
Table 5.1: Customer Insights

Insight	Summary
Customers are not aware of Australian Gas Networks.	The vast majority of customers were not aware of the name or role of AGN prior to the workshop.
Customers do not understand the structure of the gas industry.	Customers did not understand the breakdown of the gas industry (or gas supply chain) and the regulatory model under which AGN operates. They did not know that separate businesses owned and operated different elements of the gas supply chain.
Customers traditionally considered gas a cost-effective alternative to electricity but are concerned with recent price increases.	Customers have the perception that the cost-effectiveness of using gas has been eroded in recent years. Customers were still generally accepting of their current price but held a sense of uncertainty over perceived recent upward trends.
Customers would like AGN to be more visible, believing it would improve their experience as customers.	Customers want more information on AGN's role as a gas distributor and believe that some background knowledge would allow them to know where to look for more information if they require. For example, customers suggested that if they were adequately informed about changes to distribution costs they would be better placed to deal with their retailer when negotiating their retail contracts.
Customers would like to access more information from AGN and favour digital channels.	Customers indicated that they would like to use multiple communication methods to interact with AGN. They generally prefer 'real time' digital channels for greater immediacy and convenience and more traditional communication methods for planned interruptions to their gas supply.
Customers view gas as a reliable source of energy and value the current standard of reliability.	Customers stated that they were satisfied with their current reliability levels and did not support investment to deliver improved reliability (nor did they support lowering prices in return for lower reliability levels). Customers have a slight preference towards longer and less frequent outages over shorter but more frequent outages.
Customers are supportive of initiatives that maintain the reliability and improve the safety of the networks.	Customers felt strongly that the mains replacement program was a necessary investment to maintain safety. Customers are supportive of various other initiatives aimed at improving safety, such as investing to increase the awareness of the location of our gas assets and to install safety devices on new and replacement meters to minimise fire risk. Customers are supportive of projects that are based on upgrading capacity to maintain current reliability levels and to meet customer growth. Customers are less supportive of initiatives when network assets are within the control of individual customers. For example the project to gain access to certain inaccessible gas meters for meter reads and safety checks.
Customers value the control gained by having their gas bill dependent on usage levels.	The majority of customers indicated a preference to retain the current gas tariff structure, with a relatively high variable component.
Customers would like AGN to play a leadership role in minimising environmental impact.	Customers want AGN to increase transparency over its own actions and on other parts of the natural gas supply chain (including the upstream production and supply of gas).

Customers were asked to vote for the initiatives that they were supportive of AGN undertaking (mindful of the cost impact), by completing a worksheet independently to other workshop participants (consistent with the advice of the CCP). Participants were then asked to rank the initiatives in order of importance. The results of this independent assessment, which are shown in Figure 5.4, provide AGN with guidance as to both the total and relative levels of support.

Overall, customers indicated strong support for most of the initiatives tested, with the completion of our mains replacement program clearly ranked as the highest priority.

Figure 5.4: Total and Relative Workshop Support for AGN's Proposed Initiatives



5.6. Implementation Phase

The Implementation Phase focuses on embedding the findings from the Research Phase into this Draft Plan and our AA Proposal. The key activities include preparation of and engagement on the Draft Plan, further customer workshops to discuss our approach and stakeholder engagement on our AA Proposal.

5.6.1. Draft Plan

The preparation of this Draft Plan is an important part of our stakeholder engagement program. This Draft Plan sets out our preliminary views on the services we will offer, the costs we expect to incur and the prices we propose to charge over the next AA period. The Draft Plan therefore provides stakeholders with an important opportunity to provide feedback on our plans before we prepare our final AA Proposal at the end of this year.

As noted in Section 5.5, there has already been considerable internal and external consultation leading into the development of the Draft Plan, including:

- the customer workshops across our networks;
- consideration of the Customer Insights Report with our Reference Groups and within AGN; and
- consideration of the learnings from stakeholders and the AER from the recent South Australian AA review process. Our Draft Plan for Victoria and Albury reflects the same approach to forecast expenditure and demand as that applied by the AER for our South Australian network. We have also used the AER's preferred approach to determine the rate of return.

Tables 5.2 and 5.3 summarise the specific outcomes from our customer workshops (as reported by Deloitte), and how these have been factored into our Draft Plan. Table 5.2 details how the customer insights (as listed in Table 5.1) have been incorporated into the Draft Plan, whereas Table 5.3 provides a summary of how the specific reliability and safety initiatives discussed in our customer workshops have been incorporated into our proposed expenditure.

Other relevant engagement on this Draft Plan includes:

- *Incentives* – AGN, along with the other two gas distributors in Victoria, are currently in the process of engaging with stakeholders on appropriate incentive arrangements to apply to gas distributors (see Section 12); and
- *Mains Replacement* – we have commenced a dedicated stream of engagement with Energy Safe Victoria (ESV) on our mains replacement plan (see Section 8).

Table 5.2: Incorporation of Customer Insights

Insight	Incorporation into Draft Plan
Customers are not aware of Australian Gas Networks.	We are currently delivering a project that will be completed in the next AA period to develop and implement a digital platform (i.e. website) that will improve our ability to engage with customers and various industry partners. A key outcome of this project is the delivery of a better user journey and improved website content, which should assist customers in better understanding who we are and our role within the industry, particularly as it relates to the process of connecting to our network. Additionally, we are proposing to increase the scope of our current marketing activities (conducted in regional areas only at this stage) to incorporate our metropolitan Melbourne network (our Marketing Strategy). The aim of this project is to increase our customer base, thereby reducing customer bills as a result of our largely fixed costs spread across a larger number of customers. These projects are discussed in further detail in Sections 7.7.2 and 8.7.
Customers do not understand the structure of the gas industry.	As an objective of our digital program, we will aim to ensure that we clearly describe the structure, roles and responsibilities of relevant bodies within the gas industry on our website. In particular, our new website will feature information to assist customers in understanding the structure of the gas industry, the regulatory model under which AGN operates, AGN's role within the regulatory model and AGN's component of customer bills.
Customers traditionally considered gas a cost-effective alternative to electricity but are concerned with recent price increases.	We understand that customers are concerned with the uncertainty associated with future gas prices. We have kept this front of mind in the development of our Draft Plan. Our preliminary modelling incorporates the customer benefits of efficiencies we have achieved in the current AA period and lower financing costs, which results in an 11% upfront price cut to customers from 1 January 2018. Further explanation of this price cut is detailed in Section 13.3.
Customers would like AGN to be more visible, believing it would improve their experience as customers.	Consistent with our response to the insights above, we are currently improving our digital capabilities and proposing to increase our marketing activities over the next AA period. We have also increased our media presence through a series of media releases around key issues impacting our business (for example, announcements of key network extensions and pricing decisions). For further discussion on these initiatives, please refer to Sections 7.7.2 and 8.7.
Customers would like to access more information from AGN and favour digital channels.	We consider that this insight is consistent with our current focus on improving our digital capabilities, with a particular emphasis on improving our ability to communicate with customers using digital channels (such as our website). This project is discussed in further detail in Section 8.7.
Customers view gas as a reliable source of energy and value the current standard of reliability.	Our expenditure proposal detailed in this Draft Plan proposes opex and capex below current levels and is consistent with maintaining current levels of service and reliability. Built into our proposed forecasts are several key projects that we have identified as required in order to ensure the current standard of reliability is maintained over the next AA period in particular areas of our network. These projects are discussed in further detail in Section 8.
Customers are supportive of initiatives that maintain the reliability and improve the safety of the network.	We are proposing a range of projects to improve the level of safety across our network. For example, the completion of our low pressure mains replacement program and installation of fire safety valves in order to reduce the safety risks associated with bushfires. These projects are detailed in Section 8.
Customers value the control gained by having their gas bill dependent on usage levels.	As the majority of customers (74%) indicated support for a large degree of variability in their gas bills (i.e. through a larger variable component), AGN has retained the current style of gas tariff structure for the next AA period. For further information regarding our proposed tariff structures, please refer to Section 13.
Customers would like AGN to play a leadership role in minimising environmental impact.	As detailed in AGN's Environmental Policy, we are committed to seeking economic ways to reduce greenhouse gases emitted from our gas distribution networks and we are continuing to seek additional feedback about particular initiatives that we may be able to undertake over the next AA period.

Table 5.3: Incorporation of Reliability and Safety Initiatives into Draft Plan[6]

Initiatives	Question	Result	Incorporation into Draft Plan
Mains replacement	Complete remaining 300 kilometres (approximate) of our mains replacement program.	95%	In addition to receiving 95% support for this initiative, completing our mains replacement program was clearly ranked as the highest priority for all customers. AGN considers the delivery of our mains replacement program consistent with the customer support received for projects improving the overall safety of our network, and as such, has incorporated into our Draft Plan 307 kilometres to complete the low pressure mains replacement program. Further detail on this program is included in Section 8.5.
	Do nothing.	5%	
Dandenong-Crib Point	Construct new duplicate transmission pipeline to provide supply to region once capacity is reached in 2019.	85%	85% of workshop participants supported the delivery of this augmentation project. This project has been incorporated into our proposed expenditure in order to ensure the ongoing reliability of supply to customers supplied from this main. Discussion on this project is detailed in Section 8.9.
	Do nothing.	15%	
Various other augmentation projects	Undertake works to upgrade assets.	86%	Consistent with the insight that customers valued initiatives aimed at maintaining the current level of reliability provided, customers indicated 85% support for a range of additional augmentation projects to be delivered over the next AA period. Each of these projects have been incorporated into our expenditure proposal and are discussed in further detail in Section 8.9.
	Do nothing.	14%	
Public Awareness	Update Dial Before You Dig (DBYD) form.	21%	Although there was mixed sentiment as to which approach was the more effective balance of risk and cost, customers leant toward supporting a comprehensive approach to improving public awareness of our gas assets, with 49% of customers supporting the most comprehensive campaign scope. We have considered this feedback and have developed an alternative project scope that seeks to ensure an effective balance of risk mitigation and cost efficiency. The amended scope is more consistent with the targeted marketing option. This project is discussed in further detail in Section 7.7.2.
	Targeted marketing (trade magazines) and update DBYD form.	28%	
	TV/radio campaign, target marketing and update DBYD form.	49%	
	Do nothing.	3%	
Inaccessible Meters	Take action to access meter by increased communication and/or relocating meter.	60%	Around 60% of customers supported AGN gaining access to meters when they are otherwise inaccessible on a property. We found that customers are less supportive of this initiative given that these meters are within the control of individuals. This level of support is relatively low (but still reasonable), however at this stage we have moderated the cost of this project and have incorporated it in our capex proposal in order to seek further feedback from stakeholders. We will continue to consider the inclusion of this project in the lead up to the submission of our AA Proposal to the AER. Further detail relating to this project is provided in Section 8.11.
	Do nothing.	40%	
Fire Safety Valves	Fit devices in bushfire areas only.	31%	94% of customers supported the installation of fire safety valves (thermal safety devices (TSDs)) to gas meters in order to improve the fire preparedness of properties, whilst more support was provided for rolling out TSDs to all new and replacement meters (i.e. not restricted to bushfire risk areas only). We have incorporated this project into our proposed expenditure plans, however have restricted the scope to the installation of TSDs to all new and replacement meters in bushfire risk areas only as we consider that this achieves an appropriate balance between managing both risk and cost. That said, we will consider feedback in relation to this project as we develop our AA Proposal. This project is discussed in more detail in Section 8.11.
	Fit devices to all new and replacement meters.	63%	
	Do nothing.	6%	

Note: Totals may not add due to rounding.

6 Note: Please refer to Deloitte's "*Customer Insights Report*" for further detail regarding Preference Voting.

5.6.2. Further Customer Workshops

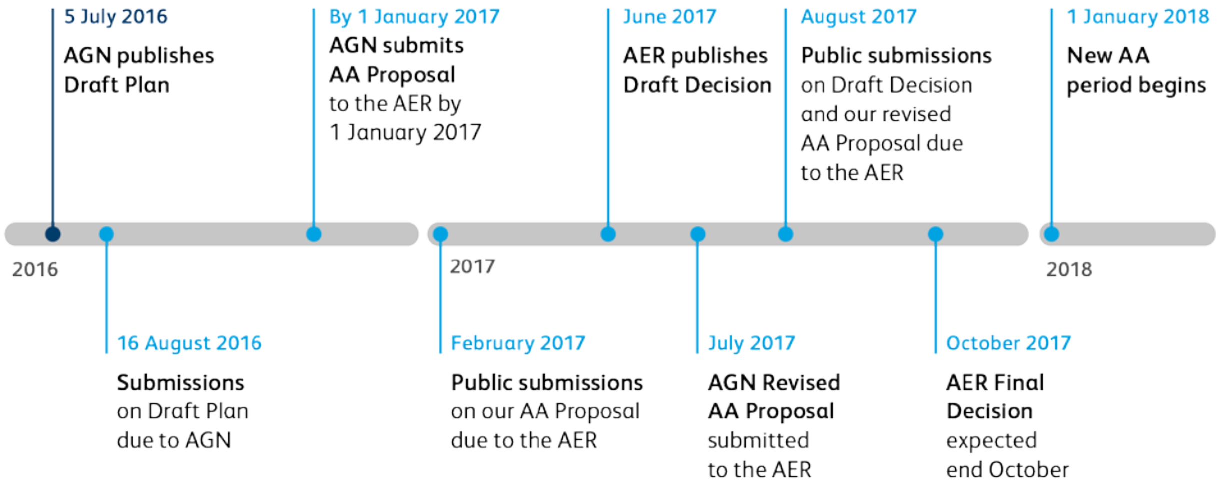
AGN will consider and respond to all of the feedback received on this Draft Plan. Once we have considered this feedback, we intend to hold further customer workshops across our networks on our revised plans. This will allow AGN to confirm (or validate) that we have appropriately incorporated stakeholder feedback into our plans prior to finalising our AA Proposal. The nature of the workshops will be similar to that undertaken in the Research Phase (see Section 5.5.1).

5.6.3. AA Proposal

The final step will be to incorporate all of the feedback received across our stakeholder engagement program into our AA Proposal. AGN intends to transparently report on the feedback received and how we have reflected that feedback into our proposal to the AER. AGN will then continue to engage with stakeholders on our AA Proposal, while the AER will also undertake its own engagement program.

Figure 5.5 summarises the key dates for the review of our AA Proposal, including outlining key engagement opportunities.

Figure 5.5: Historic and Future Key Milestones



5.7. Ongoing Engagement

The objective of the Ongoing Engagement Phase is to both evaluate the effectiveness of our engagement activities leading into the AA Proposal and to continually engage with stakeholders.

Furthermore we are engaging with stakeholders as part of our business as usual operations. This includes engaging directly with our large industrial customers, undertaking stakeholder surveys on issues such as brand awareness and by directly measuring customer satisfaction with the service levels we provide. With regard to the last point, our customer satisfaction survey includes engaging an independent expert to:

- each month, survey customers that have had a recent interaction with AGN, including through an unplanned interruption, planned interruption and customer connection;

- measure our customer service performance in respect of the above three types of interactions; and
- report on our performance, including how this performance changes over time.

Our ongoing engagement activities allow AGN to continually understand customer and stakeholder issues and improve the service levels we provide. This engagement provides important support to our dedicated engagement as part of our AA Proposal.

5.8. Summary

AGN is committed to delivering a robust stakeholder engagement program. We consider that effective stakeholder engagement will assist the business to achieve our objective of submitting a plan to the AER that delivers for our customers and is capable of being accepted. This Draft Plan describes how we have engaged with customers and stakeholders and how the feedback received has impacted on our business plans.

We encourage our customers and stakeholders to provide feedback on the Draft Plan so this can be reflected in our AA Proposal.

Stakeholder Questions

2. Do you have any comments on the structure or implementation of our stakeholder engagement program?
3. Do you have any suggestions as to how AGN could improve on and/or extend its stakeholder engagement program?
4. Do you think this Draft Plan facilitates improved stakeholder engagement?

6. Pipeline Services

6.1. Introduction

We are required to define the type and nature of pipeline services that we intend to provide to our customers over the next AA period. Pipeline services include:

- *Reference Services* – which are those services that are likely to be sought by a significant part of the market; and
- *Non-Reference Services* – which are those services specifically requested by customers (and are also referred to as negotiated services).

This section explains the services that we intend to provide over the next AA period.

6.2. Reference Services

Reference Services comprise of Haulage Reference Services (HRS) and Ancillary Reference Services (ARS). The proposed Reference Services for the next AA period are the same as those currently applying in Victoria and Albury (see Table 6.1). The proposed Reference Services are also consistent with that recently approved by the AER for our South Australian network.

Table 6.1: Victorian and Albury Reference Services

Reference Service	Description
Haulage Reference Services	
Volume Haulage Service	The delivery of gas to those customers using less than 10 terajoules (TJ) per annum. The Volume Haulage Service has two associated prices – one for residential customers and one for commercial customers. AGN will read the meters every two months.
Demand Haulage Service	The delivery of gas to those customers using more than 10TJ per annum. There is only one price available for Demand Haulage Services and it is a capacity charge that is based on Maximum Hourly Quantity. AGN will read the meters on a monthly basis.
Ancillary Reference Services	
Meter and Gas Installation Test	On site testing to check the measurement accuracy of a meter.
Disconnection	Disconnection by installation of locks or plugs on a meter.
Reconnection	Reconnection by removal of locks or plugs on a meter.
Meter Removal	Removal of a meter at a premises.
Meter Reinstallation	Reinstallation of a meter at a premises.
Special Meter Read	Reading of a meter in addition to the scheduled meter reading.

The above HRS include the provision of unaccounted for gas and all services that are necessary in order for AGN to comply with all of its obligations. AGN believes that the above HRS and ARS will continue to be sought by a significant part of the market during the next AA period, and as such, propose that they continue to be provided from 1 January 2018.

6.3. Non-Reference Services

In certain cases a customer may require services that are different from the Reference Services, which are referred to as Non-Reference Services. These services are not sought by a significant part of the market, and as such, are not considered to be Reference Services. AGN will negotiate a price directly with the customer that is requesting a Non-Reference Service.

Stakeholder Questions

5. Is there any further information you would like on the pipeline services AGN is proposing?
6. Should AGN be changing the proposed pipeline services, if so what should we change?

7. Operating Expenditure

7.1. Introduction

AGN incurs opex in order to operate and maintain its natural gas distribution networks, respond to publicly reported gas leaks and read meters. We have applied an approach to forecasting opex that is similar to that recently used by the AER to forecast opex for our South Australian network. This section outlines our approach to forecasting opex and the key drivers of forecast opex over the next AA period.

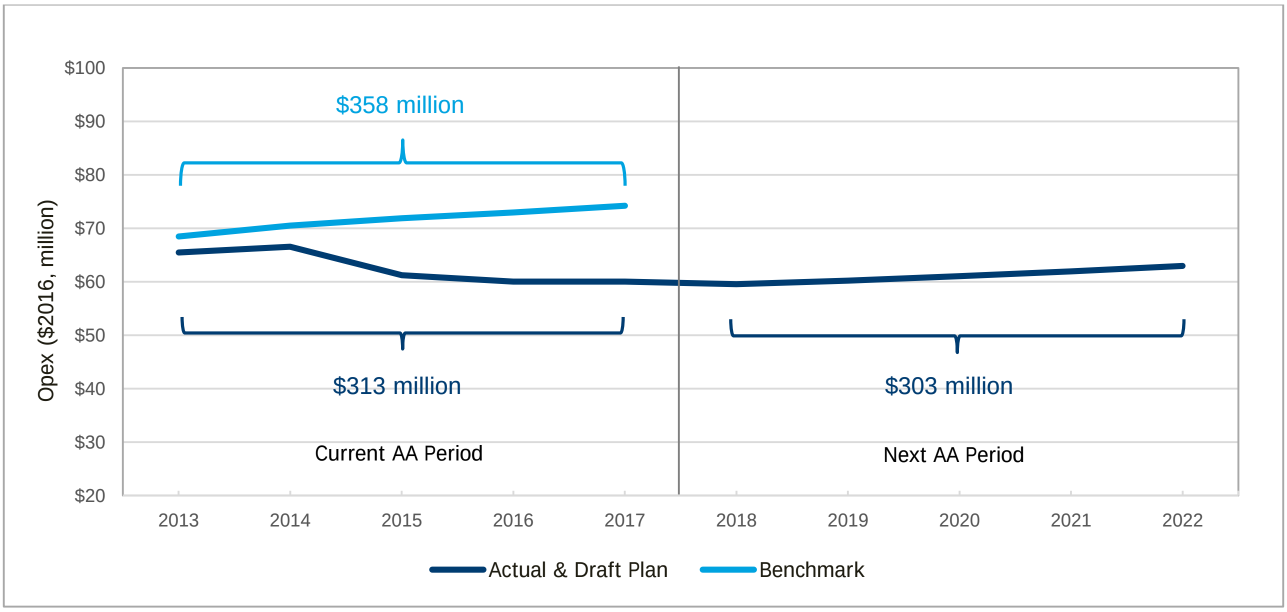
7.2. Regulatory Framework

The forecast of opex is required to reflect that required by a prudent distributor, acting efficiently and in accordance with good industry practice to achieve the lowest sustainable cost of providing Reference Services to our customers. Any forecast or estimate must be arrived at on a reasonable basis and must represent the best forecast or estimate possible in the circumstances.

7.3. Overview

Our forecast opex is 3% (or $10 million) below current levels, despite growing customer numbers and increased input costs (see Figure 7.1). We have also included an initiative to expand our marketing program by $5 million over the next AA period. We have absorbed all other identified step changes (of around $8 million) into our current cost base.

Figure 7.1: Current AA Period Actual Opex Compared to Forecast ($2016, million)



7.4. Stakeholder Engagement

We are committed to ensuring our plans have been informed by effective stakeholder engagement. Section 5 of this plan described our progress with our engagement program and how this has so far impacted our plans. We have considered and incorporated the insights from our customers in developing our proposed opex forecast, particularly around maintaining current levels of network reliability and increasing customer awareness of our business and our assets.

We consider that we will be able to maintain current levels of reliability, despite our lower opex forecasts. We will also incur opex related to certain capex projects that are aimed at maintaining reliability. We are also proposing to increase public awareness of our assets and our business in response to stakeholder feedback. We are however, not seeking any increase to our forecast opex to deliver these initiatives in response to stakeholder feedback.

7.5. Forecasting Methodology

AGN has applied a 'base year roll-forward' approach to forecast opex over the next AA period. Under this approach, we adjust actual opex incurred in 2016 (the 'base year') for costs that are not included in the base year and are expected to be incurred over the next AA period, such as growth in customer numbers. As mentioned in the previous section, we have also considered the implications of our engagement program on forecast opex, although this has not led to increases in forecast opex.

The 'base year roll-forward' approach to forecasting opex has been commonly accepted. There are minor differences in our approach to that recently applied by the AER, which relate specifically to the impact of growth in our network on our costs (see Section 7.9).

7.6. 2016 Base Year

Estimated opex in calendar year 2016 has been used as the base year to determine forecast opex for the next AA period. The 2016 base year is used because it reflects the most recent actual information relating to the scope and cost of providing Reference Services over the next AA period that is available at the time the AER makes its Final Decision (which is expected to occur around October 2017, see Figure 5.5).

Base year opex is necessarily an estimate as the 2016 calendar year is not yet complete, with the estimate in this Draft Plan comprising three months of actual opex and nine months of estimated opex. AGN will update this information in its AA Proposal to incorporate nine months of actual opex information, and after this, for a full year of actual information when we respond to the AER's Draft Decision.

The use of actual opex incurred in the 'base year' reflects that the majority of opex is recurrent in nature and the operation of the Efficiency Benefit Sharing Scheme (EBSS) provides strong assurance that base year costs are efficient. This was highlighted by the AER in its recent decision for our South Australian network:

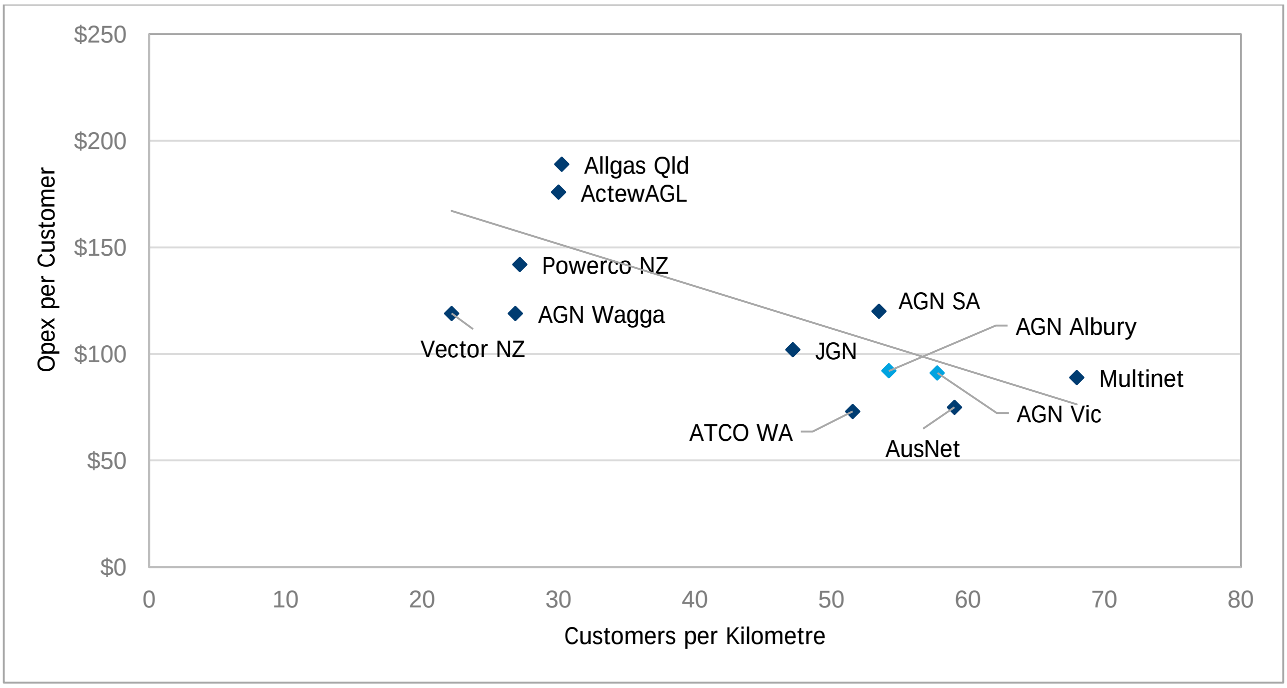
> *"AGN has been subject to [an] incentive framework for a number of access arrangement periods, including the application of an efficiency carryover mechanism for opex. In theory, AGN as a profit maximising firm should reveal its efficient costs over time, and these can be used to forecast opex into the future. Unless we have evidence that the revealed opex in a proposed base year is materially inefficient, we use the revealed costs of the service provider for our alternative opex forecast."*[7]

Our current estimate of 2016 base year opex is $56 million for both Victoria and Albury. As detailed in Section 3, we consider that our leading productivity performance supports the use of our estimated 2016 base year to forecast opex over the next AA period. We also note the following view expressed by the AER in its most recent annual electricity benchmarking report:

> *"… the most significant output of distributors is customer numbers. The numbers of customers on a distributor's network will drive the demand on that network. Also, the comparison of inputs per customer is an intuitive measure that reflects the relative efficiency of distributors."* [8]

We therefore also sought expert advice on our opex per customer relative to customer density, where customer density is the total number of customers per kilometre of mains (see Figure 7.2). This shows that our Victorian and Albury opex per customer is at the lower end of the range across all gas distributors included in the sample. This provides further support for our leading productivity performance and provides assurance that our base year opex reflects efficient costs.

Figure 7.2: Opex per Customer relative to Customer Density



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

[8] AER, "*Electricity distribution network service providers annual benchmarking report*", November 2014, pg. 23.

7.7. Non-Base Year Opex

There are a range of activities identified by AGN that we intend to provide over the next AA period that are not reflected in the 2016 base year. This includes costs associated with the delivery of a particular capital project and/or one-off or permanent or 'step' changes to business activity. The AER indicated in its recent review for our South Australian network that increases in forecast opex for step changes are not required for the following reasons:

- base year opex already includes an efficient and prudent level of expenditure;
- there is likely to be some non-recurrent expenditure in the base year (and the AER prefers not to make adjustments to the base year);
- project costs should be offset by future productivity gains; or
- costs are otherwise immaterial and should be absorbed by the business.

Consistent with the above, we have not sought to increase opex in relation to the identified step changes, aside from our proposed expanded marketing program. Our decision not to increase opex for the identified step changes results in AGN absorbing approximately $8 million into our base year opex over the next AA period, which is equivalent to achieving a 0.7% annual improvement in productivity.

7.7.1. Opex Driven by Capex

Table 7.2 sets out the opex that is driven by our proposed capex program. The total cost of these initiatives is just over $2 million over the next AA period, which costs will be absorbed into our base year (that is, we are not seeking an increase in our opex as a result of the projects listed in Table 7.2).

Table 7.2: Opex Driven by Capex Projects ($2016, million)

Step Change	Cost	Description
Business Intelligence	0.8	Consistent with our national IT program, this project relates to the ongoing opex incurred to support the roll-out of our Business Intelligence project.
Refurbish Dandenong-Crib Point Pipeline	0.6	AGN is proposing to refurbish the Dandenong-Crib Point Pipeline. As part of this project it has been identified that AGN will incur ongoing costs once every 10 years in order to conduct in line inspections and subsequent repairs on the pipeline.
Interval Meter Data Management	0.4	AGN is proposing to install telemetry facilities at all interval meters in order to collect more accurate data regarding customers' consumption of gas. The opex associated with this project is in relation to the additional data collection requirements following the installation of these facilities.
Transmission Pipeline Modification	0.3	AGN is proposing to modify the Dandenong to Frankston and North Melbourne to Fairfield transmission pipelines in order to ensure they can be subject to internal inspections. The opex associated with this project relates to conducting the internal inspections.
Geospatial Information System (GIS)	0.2	Consistent with our national IT program, these costs relate to the ongoing annual maintenance of our upgraded GIS.
Total	**2.3**	

7.7.2. Step Changes in Opex

Table 7.3 sets out the other initiatives that we do not currently provide but intend to deliver over the next AA period. In some cases, these projects reflect feedback received from our stakeholder engagement program. The total cost of these initiatives is $6 million over the next AA period, which will be absorbed into our base year opex (that is, we are not seeking an increase in our opex as a result of the projects listed in Table 7.3).

Table 7.3: Step Change Projects ($2016, million)

Step Change	Cost	Description
Gas Assets Public Awareness	2.0	This project is aimed at reducing the number of third-party strikes on our assets by increasing public awareness about the location of our underground assets (for example, by better promoting the Dial Before You Dig facility). This initiative will increase public safety and received strong support at the customer workshops.
Pipeline Integrity Assessment	2.0	This project aims to improve the baseline data that is needed to verify pipeline integrity in relation to some of our pipelines in Victoria.
GasNet Custody Transfer Meter (CTM) Charges	1.0	This project is to upgrade the CTM capacity by installing new CTM connections in line with the expected growth of our networks. This project is required in order to comply with our regulatory obligations relating to gas delivery, metering, pressure and customer connections.
Transmission Asset Drawings Update	0.6	This project is required to rectify the current inadequacies in the technical drawings currently on file in order to ensure our compliance with relevant standards and the ongoing safety of our employees and the public.
Environment Management Plans	0.5	The ESV requires AGN to develop an Environment Management Plan relating to our Victorian assets. A new requirement from the ESV requires 'line lists' to be included in the Environment Management Plan and reviewed by the ESV every two years. This project estimates the additional costs involved in conducting an initial survey, developing the 'line lists' and conducting an additional survey every two years.
Total	**6.1**	

The only step change that we are seeking additional funding for relates to our proposed expanded marketing program.

We are seeking additional funding for our marketing program on the basis that it reflects a material increase in costs that are not included in our base year. Our marketing program will deliver lower prices to customers in the medium to long term relative to the prices that would otherwise apply. This is because our marketing program will increase usage of our network, which means our fixed costs will be spread across more customers.

Marketing is required because natural gas is a fuel of choice, reflecting that there are readily available and low cost substitutes for all residential and most business uses of natural gas. As a result, and like most other businesses, we are required to market (or sell) the benefits of natural gas to customers. The competitive pressures faced by our business are expected to increase as a result of, for example, increasing penetration of renewable electricity and storage options.

Our marketing activities include working with appliance retailers, advertising and offering incentives (or rebates) for the connection of new appliances to the network. We currently undertake an expanded marketing program across our entire South Australian network where we are the only gas distributor. We currently deliver these marketing programs in our regional centres where we are the only gas distributor.

We have not however undertaken any marketing in the Melbourne metropolitan area to date because there are two other distributors in this area, which has meant that we could not market and offer rebates to customers located in our network only. To overcome this complexity, we are proposing to coordinate marketing activities with the other two gas distributors in the next AA period. Implementing this joint marketing initiative will provide for a more effective and lower cost marketing program across all of metropolitan Melbourne.

To implement this joint marketing initiative in metropolitan Melbourne, we are proposing to increase our expenditure on marketing by $5 million over the next AA period (or by $1 million per year). The implementation of this proposal is, however, dependent on the other two distributors also committing to a joint marketing program on their networks.

7.8. Input Cost Escalation

We have applied the same approach used by the AER to escalate input costs over the next AA period, which includes applying:

- the AER preferred opex resource mix of 62% labour and 38% material costs;
- no input cost escalation to material costs; and
- an average of BIS Shrapnel and the latest available forecasts from Deloitte Access Economics to determine real labour cost escalation.

The above approach results in a real (before inflation) average annual increase in opex of 0.7% over the next AA period, which is detailed in Table 7.4 below.

Table 7.4: Weighted Input Cost Escalation Rate

Escalation Rate	Weight	2017	2018	2019	2020	2021	2022
Labour	**62%**	0.7%	1.0%	0.9%	1.0%	1.4%	1.5%
Materials	**38%**	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Weighted Input Cost Escalation Rate		**0.4%**	**0.6%**	**0.5%**	**0.6%**	**0.8%**	**0.9%**

7.9. Output Growth

AGN will incur additional opex as the net number of customers connected to our networks increases (referred to as output growth).

The AER has developed an output growth factor (in the context of a review process for another business) that is based on forecast customer numbers and throughput. We have not applied this approach as we do not believe that opex is driven by both customer numbers and throughput. We accept that opex costs are driven by customer numbers but do not believe that increases or decreases in throughput have a direct relationship with opex.

Our position is supported by a recent study by ACIL Allen:

"A key characteristic of these [output growth] models is that the energy throughput variable has a negative coefficient. Moreover it is not statistically significant at the 1% level in three of the five models. These results are not surprising given that gas throughput has been declining for the majority of the distribution businesses over the period of 2005 to 2013, while operating expenditures have continued to increase. This suggests that energy (gas throughput) is no longer a key driver of increasing operating expenses for the nine gas distribution businesses under consideration."[9]

We have therefore determined output growth based on the forecast growth in net customer numbers (see Section 11) multiplied by the incremental cost of providing services to new customers. The approach taken to estimate the incremental cost per customer is consistent with:

- that approved by the AER to apply for the current AA period; and
- the incremental cost of $17 per annum (expressed in $2006) as per the 2014 Victorian Gas Distribution System Code.[10]

The forecast output growth is set out in Table 7.5.

Table 7.5: Output Growth

Incremental Cost per Customer	2018	2019	2020	2021	2022	Total
Net Customer Growth	10,050	10,218	11,538	11,495	11,453	
Incremental Cost per Customer ($2016)	24.8	25.6	26.4	27.3	28.1	
Total ($2016, million)	**0.5**	**0.8**	**1.1**	**1.4**	**1.7**	**5.5**

7.10. Productivity Growth

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

We have considered this issue and note that the cost function analysis methodology relied upon by the AER to forecast productivity in the electricity industry produces a declining forecast of productivity growth for AGN Victoria and Albury over the next AA period. If applied, this productivity growth forecast would result in an increase to our opex forecast for the next AA period. We have therefore decided not to apply this productivity factor.

We also note our historic leading productivity performance and our decision to absorb certain non-base year costs into our current opex forecast, which results in an implied productivity adjustment of around 0.7% per year.

[9] ACIL Allen, "*Productivity Study: ActewAGL Distribution Gas Network*", 29 April 2015, pg. 31.

[10] Essential Services Commission of Victoria, "*Gas Distribution System Code*", October 2014, pg. 44.

7.11. Summary

Forecast opex for the next AA period is $303 million, which is 3% below actual opex incurred in the current AA period, despite a growing customer base (see Table 7.6). The forecast is based on actual opex incurred in 2016, which will necessarily be estimated up until actual information is available. Our 2016 'base year' opex will reflect the most recent actual information relating to the scope and cost of providing Reference Services over the next AA period.

Our leading productivity performance supports the use of our estimated 2016 base year to forecast opex over the next AA period. We have not adjusted base year costs for most step changes that we intend to deliver over the next AA period, including as a result of stakeholder feedback or opex that is related to our proposed capex program. We have included additional opex for our expanded marketing program, which is aimed at lowering prices to existing customers.

Table 7.6: Opex Forecast Summary ($2016, million)

Opex Component	2018	2019	2020	2021	2022	Total
2016 Base Year Estimate	56.2	56.2	56.2	56.2	56.2	**281.0**
Non-Base Year Costs	1.0	1.0	1.0	1.0	1.0	**5.0**
Output Growth	0.5	0.8	1.1	1.4	1.7	**5.5**
Input Cost Escalation	0.6	0.9	1.3	1.8	2.4	**7.0**
Debt Raising Costs	0.9	0.9	0.9	1.0	1.0	**4.6**
Total	**59.2**	**59.8**	**60.5**	**61.4**	**62.3**	**303.2**

Stakeholder Questions

7. Do you consider we have applied an appropriate approach to forecasting opex?
8. Should the non-base year costs outlined in this section be added to our opex forecast or be absorbed by the business?
9. Do you support our proposal to expand our marketing program over the next AA period?
10. Do you consider that increases in opex attributable to the growth of our network are appropriately captured through growth in customer numbers (or should growth in throughput also be accounted for)? Should any output growth factor that is developed for gas distribution be subject to industry-wide consultation before it is introduced?

8. Capital Expenditure

8.1. Introduction

AGN incurs capex in order to connect new customers to the network and to ensure the ongoing safe and reliable supply of natural gas to our customers. As with opex, our approach to forecasting capex is consistent with that used by the AER to forecast capex for our South Australian network. This section outlines our approach to forecasting capex and the key drivers of forecast capex over the next AA period.

8.2. Regulatory Framework

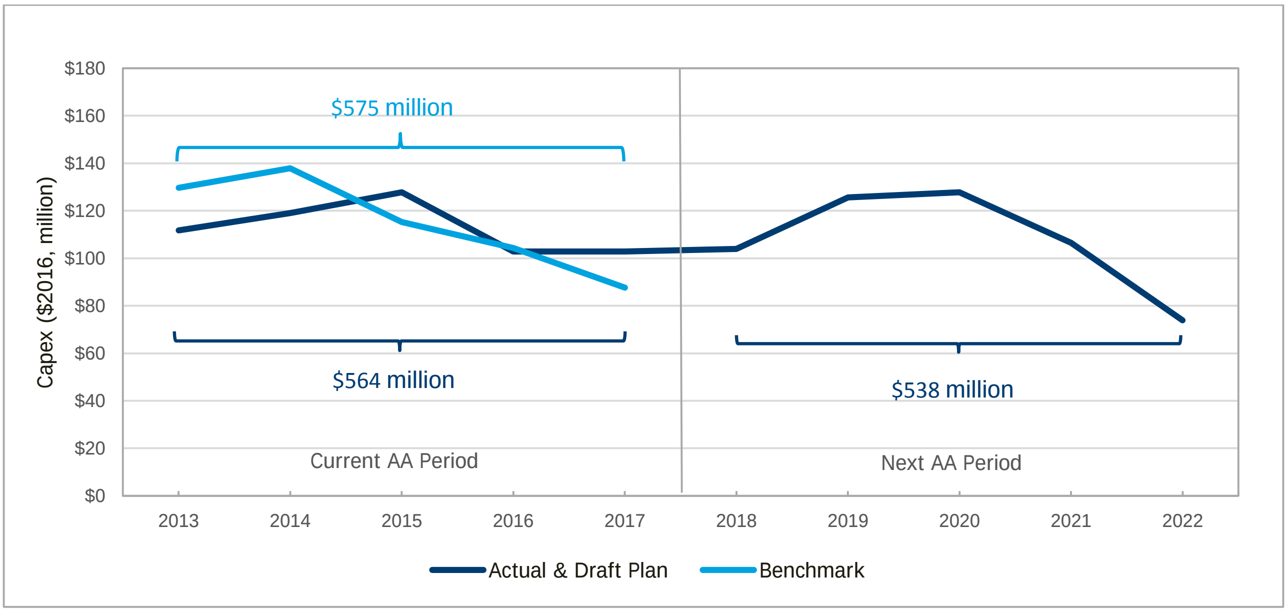
Our forecast capex is required to reflect that required by a prudent distributor, acting efficiently and in accordance with good industry practice to achieve the lowest sustainable cost of providing Reference Services to our customers. Forecast capex must also satisfy various additional criteria, including to maintain and improve safety, to maintain network integrity, to comply with our obligations, to meet network demand and to ensure that any revenue generated exceeds the associated costs.

Any forecast or estimate must be arrived at on a reasonable basis and must represent the best forecast or estimate possible in the circumstances.

8.3. Overview

Our forecast capex is 5% (or $26 million) below current levels, driven mainly by the completion of our low pressure mains replacement program (see Figure 8.1). Other key components of our capex forecast include the ongoing nationalisation of our IT capabilities and the forecast connection of around 14,000 new customers to our network each year.

Figure 8.1: Comparison of Actual Capex to Forecast Capex ($2016, million)



8.4. Stakeholder Engagement

We have reflected the outcomes of our stakeholder engagement program throughout our forecast capex proposal, particularly in regard to those initiatives that are aimed at improving network safety and maintaining current levels of reliability. More specifically, we are proposing to:

- maintain and improve network safety primarily through the completion of our low pressure mains replacement program, which received particularly strong support through our stakeholder engagement program;
- maintain current levels of supply reliability by completing several key network augmentation projects, including completing our long term project to reinforce supply to customers connected on the outer eastern network down to the Mornington Peninsula;
- improve our ability to communicate with customers by improving our digital capabilities; and
- introduce a program of installing thermal safety devices to all new and replacement meters in bushfire risk areas, following strong support for this initiative in our customer workshops.

This section describes the key elements of our capex forecast in more detail.

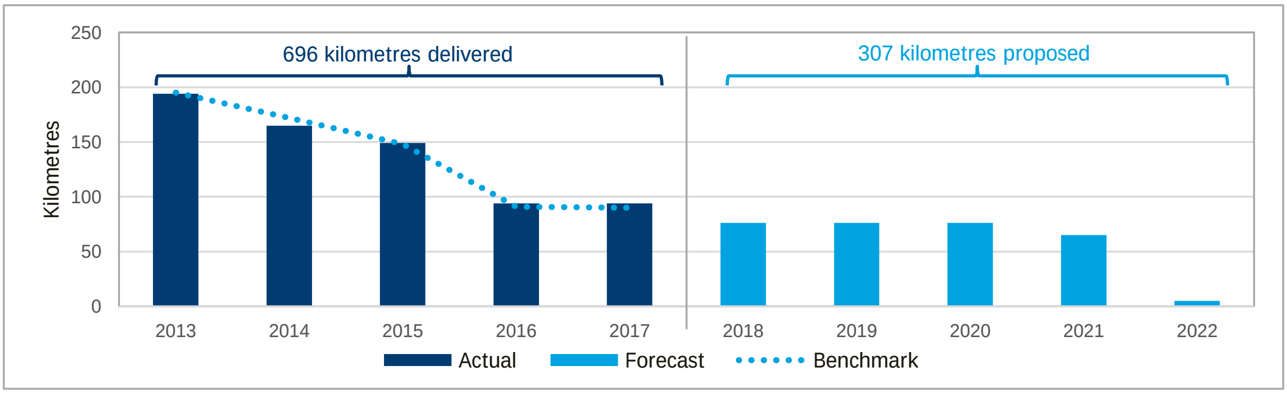
8.5. Mains Replacement

The provision of a safe and reliable supply of natural gas is the most important driver of business performance. A key part of ensuring public safety is our mains replacement program, which sets out the strategy for the replacement of ageing/deteriorating mains on our network to maintain and improve safety.

Importantly, we have demonstrated a strong commitment to delivering our mains replacement program. We are forecasting to complete the full 696 kilometres of mains replacement that was included in the capex benchmarks for the current AA period. We are planning to complete our low pressure mains replacement program, which was considered to be the highest priority initiative at the customer workshops.

We are forecasting to spend $151 million on replacing 307 km of mains and associated risk mitigation activities over the next AA period[11]. This represents a reduction of almost $100 million compared to the amount forecast to be incurred in replacing 696 kilometres of mains over the current AA period (see Figure 8.2).

Figure 8.2: Mains Replacement Program Volumes



11 Note: All dollar terms stated in this section regarding the Capex Driver Categories are reflective of direct costs only (i.e. exclusive overheads and input cost escalation), whereas the percentages incorporate the impact of overheads and input cost escalation.

This section explains the risk assessment, volume and cost of our mains replacement program. The forecast cost is based on determining the number of kilometres of mains that require replacement over the next AA period and multiplying these kilometres by a unit rate that has been based on (in most instances) a historic average of competitively tendered rates.

8.5.1. Forecast Volume of Mains Replacement

The volume of mains replacement has been determined by applying the relevant Australian Standard 4645 (AS 4645). The standard requires an assessment of the consequence and likelihood of an identified risk occurring and then sets out requirements around addressing the risk. Any risks that are rated as 'extreme', 'high', or 'intermediate' must be reduced to 'low' or 'negligible' as soon as possible.

Our risk assessment has identified that:

- There are no mains in our network rated as 'extreme' risk;
- There are 25 kilometres of cast iron (CI) and unprotected steel (UPS) mains located in the Melbourne central business district (CBD) that are rated as 'high' risk. All of these mains will be replaced over the next AA period;
- The CI and UPS mains and polyvinyl chloride (PVC) mains that are in high density inner city suburbs (HDICS) are also rated as 'high' risk. There are 216 kilometres of these mains that will be replaced over the next AA period;
- Some of the CI and UPS, PVC and high density polyethylene (HDPE) mains over 35 years old are rated as 'intermediate' risk. There are 652 kilometres of these mains. We are proposing to replace only 62 kilometres of these mains during the next AA period, consisting of 17 kilometres of CI and UPS and 38 kilometres of PVC mains integrated within the low pressure network in low density suburbs (LDS) and seven kilometres of the oldest HDPE mains in our network; and
- The HDPE mains younger than 35 years old are currently rated as 'low' risk. However, AGN will replace three kilometres of these mains as part of a sampling program to gather information to inform whether a possible future replacement program is required.

As such, our forecast volume of mains replacement over the next AA period ensures:

- all of the mains rated as 'high' risk are replaced during the next AA period;
- the risk associated with mains identified as 'intermediate' risk will be managed by either:
  - replacing the mains where it is prudent and efficient to do so; or
  - continuing to mitigate the risk by other means, such as managing the operating pressure, undertaking leak surveys and commencing an in-line camera inspection program.
- investigative work and a sampling program will be conducted in order to inform the approach to any future replacement program of ageing HDPE pipe.

Included in our mains replacement forecast is a relatively smaller cost that is associated with service renewals that are performed as we deliver our mains replacement program.

We consider that the above replacement program is consistent with our obligations under the relevant standard, including managing risk on our network to as low as reasonably practicable.

8.5.2. Forecast Cost of Mains Replacement

To estimate the cost of the mains replacement program, we have developed a unit rate for each main type and assessed the costs that might result from locational characteristics where the mains are to be replaced. Our forecast unit rates are based on and supported by the outcomes of our competitive tender processes. More specifically:

- Where the works planning process is at the stage where the tender for the work during the next AA period has commenced, and tendered rates are available, those rates have been adopted;
- Where work packages are similar to the work subject to the tender process referred to in the above point, the unit rates from comparable tenders have been adopted;
- Where adjustments to tendered rates are made, these are based on actual variations experienced from prior work packages;
- Where tendered unit rates for comparable packages of work are not available, historical actual unit rates have been adopted; and
- Where work is not comparable to available tendered rates or historical actual unit rates, assumptions have been made to support forecast expected variations by work package.

We consider that our reliance on the outcomes of competitive tenders and actual experience and costs ensures our forecast capex is consistent with determining the lowest sustainable cost of replacing the required volume of mains over the next AA period.

8.5.3. Summary

Our proposed mains replacement program is based on ensuring network risk is managed in a manner that is consistent with appropriate industry standards and regulatory obligations.

Our proposal will lead to the completion of the low pressure mains replacement program that we have been undertaking over the current AA period, thereby improving safety on the network. Our reliance on competitively tender outcomes ensures the cost of the program is efficient.

The completion of our mains replacement program received strong support in the customer workshops. In particular, the completion of our low pressure mains replacement program received support from 95% of participants at the customer workshops. We have also commenced dedicated engagement on our proposed mains replacement program with the ESV.

Table 8.1 summarises the resulting volume and cost of the mains replacement program over the next AA period. Our mains replacement capex accounts for around 31% of our total capex over the next AA period.

Table 8.1: Mains Replacement Forecast ($2016, million)

Replacement program	Cost
High density inner city suburbs CI and UPS and PVC	76.6
Central business district CI and UPS	30.0
Low density suburbs CI and UPS and PVC	22.8
CI and UPS trunk	9.6
HDPE end of life program	5.6
HDPE sampling program	2.4
High density inner city suburbs and low density suburbs piecemeal	1.6
Ongoing service renewals	2.5
Total	**151.1**

8.6. Growth

Our growth capex relates to the costs required to facilitate new customer connections to our network. Our growth capex is therefore driven by the number of new customers we expect to connect to our network over the next AA period, which is discussed in Section 11.3. Growth in customer numbers assists to lower prices to existing customers by spreading the largely fixed costs of operating our network across a larger customer base.

Growth capex is determined by multiplying the forecast number of new customer connections by the costs associated with those new connections, which costs include:

- *Mains* – the average cost of extending our network to connect the new customer;
- *Services* – the average cost of providing a service (or inlet) from our mains to the customer meter; and
- *Meters* – the average cost of installing and commissioning a meter at the customer site.

The total growth capex over the next AA period is $142 million based, which accounts for around 30% of our total capex over the next AA period (see Table 8.2). .

Table 8.2: Growth Forecast ($2016, million)

	2018	2019	2020	2021	2022	Total
Growth Forecast	26.5	27.0	29.5	29.6	29.7	**142.3**

8.7. Information Technology

We are required to handle substantial amounts of information on a daily basis, including information relating to customer connections and disconnections, managing gas repairs as well as meter reading and billing information. This volume of activity requires ongoing investment in systems that link together to allow the high volume of data to flow between systems. This will ensure full system functionality to manage critical business processes and to satisfy retail market rules.

We have initiated a national program of work in the current AA period to replace our old state-based IT systems, which are over ten years old and are no longer supported by the appropriate vendor nor able to be updated to prevent system security vulnerabilities. New enterprise equivalents servicing all five jurisdictions in which AGN operates are being implemented.

The key benefits of our national IT program include improved safety, operational performance and cost performance by implementing standard systems across our network. Considerable progress has been made towards the nationalisation of our IT systems and infrastructure over the current AA period. This includes the installation of our enterprise asset management (EAM) system, which supports standard national processes across all five Australian jurisdictions in which AGN operates.

AGN is proposing to continue with this national IT program over the next AA period. The forecast IT investment for the next AA period is required to:

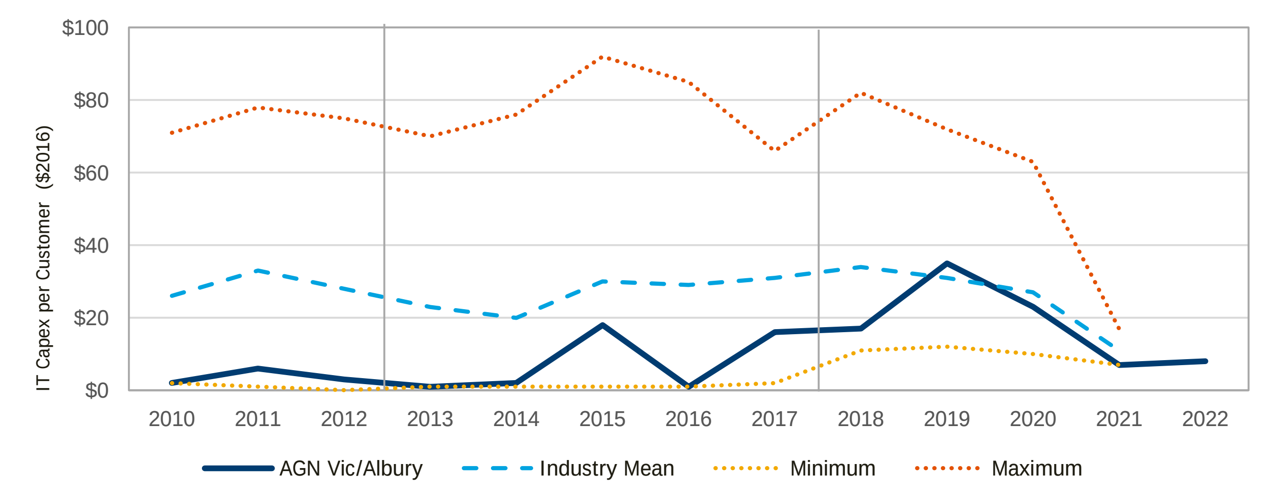
- complete the nationalisation program of work that commenced in the current AA period;
- mitigate the risks associated with our core operating systems;
- enable the effective and efficient delivery of services to our customers; and
- ensure compliance with regulatory obligations (for example, the Retail Market Procedures).

A failure to complete the nationalisation program of work in the next AA period will limit the benefits from investments made in the current AA period (including in our other networks), increase the risk of non-compliance with relevant regulatory obligations, lead to customer and business interruptions, potential public safety issues and the corresponding adverse financial and reputational consequences.

Our current and forecast IT spend comes after a sustained period of lower than sustainable investment. We engaged an expert adviser to compare our actual IT spend over the previous (2008 to 2012) and current AA periods and our forecast IT spend over the next AA period against a sample of around 20 other Australian utilities.

The analysis shows that our IT capex per customer is at or below the sample average over the entire 15 year period and consistent with the minimum IT capex per customer over the past 10 years (see Figure 8.3).

Figure 8.3: IT Capex per Customer ($2016)



Given our program of nationalisation, the IT projects we are proposing to deliver over the next AA period in our Victorian and Albury networks are the same as those proposed and accepted by the AER in their Final Decision for our South Australian network. We consider this expenditure is also consistent with our stakeholder feedback regarding initiatives that maintain the reliability and improve the safety of our networks.

Each of these projects are described in Table 8.3 and include the installation of new IT systems (geographical information system, business intelligence system and mobility system) and maintenance of existing systems (through periodic applications renewal). Our total forecast IT capex is around $62 million over the next AA period, which accounts for around 13% of total capex.

Table 8.3: IT Projects ($2016, million)

IT Project	Cost	Summary
Applications Renewal	22.0	This project ensures application systems for the Metering and Billing System, Telemetry System, GIS and Enterprise Asset Management System are updated to ensure their ongoing reliability. This project is required to perform upgrades on existing IT assets and does not involve their replacement.
Geographical Information Systems	16.2	This project provides for an upgrade to the GIS, which manages all geographic data associated with our networks (that is, the GIS maps the location of network infrastructure). This project will mitigate a significant business risk associated with our currently unsupported GIS application and integrate the GIS into the broader EAM suite of IT applications. Implementation of this new system will ensure the ongoing safe operation of our networks as our employees and the public can continue to access reliable information regarding the location of our assets (for example, through the Dial Before You Dig facility). This project is also consistent with our findings that customers place a strong emphasis on improving knowledge of the location of our assets.
Business Intelligence	11.1	This project will provide improved information and reporting across AGN by utilising data from the disparate IT applications that are used within the business. This project will provide a toolset that will improve data quality, streamline reporting effort and allow greater access to information for optimised decision making.
Mobility Integration	10.4	This project provides for the mobile integration of resources across our networks. This includes improving network performance by automating current paper-based and manual processes through the use of mobile devices and integrated processes.
Next Generation Operating Environment	1.3	This infrastructure renewal project relates to the upgrade of desktop infrastructure and telephony infrastructure.
Digital Capabilities	1.4	This project develops a range of digital capabilities aimed at delivering a customer service experience consistent with the delivery of services by other distributors (and businesses more generally). This project is consistent with our findings that customers would like to access more information from AGN through digital channels.
Total	**62.4**	

8.8. Meter Replacement

We are required to periodically change gas meters in order to test them for metering accuracy and replace those meters that do not meet the necessary accuracy standards. These periodical meter changes (PMCs) take place as a result of condition-based assessment, with replacement generally occurring after a meter reaches 15 years of age. This continuous changeover and testing program ensures that each gas meter continues to operate within required accuracy limits. Our obligations and associated processes are approved annually by the AER.

The number of meters requiring changeover reflects the condition and types of meters in service and are required for AGN to comply with its regulatory obligations (specifically AS 4944). Additionally, AGN supplies periodic reports to the AER that detail results of our meter testing programs. As our requirements are well documented and tracked, the forecast quantity of PMCs have a high degree of certainty.

The cost of this activity is also well established, with this cost mostly dependent upon two factors:

- *Forecast cost of new meters* – which is based on the outcomes of our competitive tender process; and
- *Forecast mix of new and repaired meters* – which is based on our long term practice of repairing meters wherever possible in order to minimise costs.

The volume of meters to be replaced is forecast to increase over the next AA period compared to the current AA period due to the following two key factors:

- there is a large number of meters that are reaching 15 years of age, and as such, require testing (as set out in AS 4944) and replacement; and
- relatively high numbers of meter connections over the past few years, which require testing after three to five years of operation (as set out in AS 4944), thereby resulting in an increase in the volume of testing and replacements forecast over the next AA period.

Our total forecast meter replacement capex is around $40 million over the next AA period, which accounts for around 8% of total capex (see Table 8.4).

Table 8.4: Forecast Meter Replacement ($2016, million)

	2018	2019	2020	2021	2022	Total
Residential	4.3	4.3	4.3	4.3	4.3	**21.4**
Commercial	3.8	3.8	3.8	3.8	3.8	**18.7**
Total Forecast	**8.0**	**8.0**	**8.0**	**8.0**	**8.0**	**40.1**

Note: Totals may not add due to rounding.

8.9. Augmentation

Gas flows through our network are continually reviewed to ensure there is adequate capacity and pressure to meet customer demand. Network modelling, based on pressure and flow data and forecast customer growth, indicates those parts of the network that are likely to require reinforcement (or augmentation). This process results in projects that are aimed at ensuring there is sufficient:

- capacity to ensure that our network is capable of continuing to meet the demand for services, particularly in areas of high growth;
- capacity to ensure the availability of high pressure gas to support the systematic and planned replacement of mains (as explained earlier in Section 8.4); and
- protection of the networks from over-pressurisation, which can occur if key pressure regulator facilities fail to operate as designed.

The key projects are described in Table 8.5 and aim to maintain the reliability and security of supply to customers. These projects are consistent with stakeholder feedback for AGN to maintain reliability levels, with the below projects receiving strong support from workshop participants. Overall, we are proposing augmentation capex of $38 million over the next AA period, which accounts for 8% of total capex.

Table 8.5: Key Augmentation Projects ($2016, million)

Augmentation Project	Cost	Description
Dandenong-Crib Point	14.5	The Dandenong to Crib Point Pipeline was originally constructed in 1966 and delivers natural gas to around 110,000 customers from the Dandenong City Gate down to the Mornington Peninsula. Capacity issues on this main has resulted in the staged construction of a parallel main, with the final stage now required. This project is to provide capacity to meet ongoing customer growth and maintain network reliability. This project received 85% support from workshop participants.
Cranbourne High Pressure Augmentation	9.5	Ongoing connections in and around Cranbourne will require network reinforcement to support customer growth while maintaining network reliability to existing customers.
Morwell Tramway Road Transmission Pressure Main	4.5	The Morwell to Tramway pipeline is one of the oldest pipelines in Australia. The ESV is currently reviewing whether the main is in sufficient condition to provide services, this review will be finalised in August 2016. The project scope will depend on the outcomes of the ESV review.
City Gate and CTM Upgrades	2.4	Natural gas is delivered into our network from transmission pipelines through city gates (or custody transfer meter stations). Major works at three entry points (Berwick, Lindrum Road and Sale) are required in the next AA period to ensure appropriate gate station capacity.
Other	7.4	Various smaller projects to maintain the integrity of services and reliability of our networks.
Total	**38.3**	

8.10. Telemetry

AGN relies on telemetry or Supervisory Control and Data Acquisition (SCADA) for the real-time monitoring of network conditions and, in some cases, for the remote control of gas flows and pressures to optimise system performance and maximise safety. Over the next AA period, AGN is proposing to spend $4 million on telemetry projects, in order to:

- more effectively manage monthly meter reading of large customer sites and the resulting data; and
- extend the SCADA network to regional towns and certain fringe points of the network.

This expenditure is consistent with the finding that customers are supportive of initiatives that maintain reliability and improve the safety of our network. Our telemetry capex forecast of around $4 million accounts for 1% of total capex (see Table 8.6).

Table 8.6: Telemetry Forecast ($2016, million)

	2018	2019	2020	2021	2022	Total
Telemetry	0.3	1.8	1.4	0.2	0.1	**3.8**

8.11. Other Assets

There are various other items of capex that do not fall into a specific category but are still required to provide services to our customers. These projects include the following:

- *Ongoing refurbishment and replacement of assets ($9 million)* – assets such as city gate valves and commercial meter sets can have their useful lives extended by undertaking refurbishment works, while items such as SCADA remote terminal units, cathodic protection, regulators, valves and flow correctors require replacement;
- *Modification of the Dandenong to Frankston and Dandenong to North Melbourne transmission pipelines ($14 million)* – to enable more effective condition monitoring via internal inspection to detect steel defects;
- *Bushfire Preparedness ($3 million)* – while 92% of workshop participants supported the installation of thermal safety devices to new and replacement meters in all areas, we are proposing to restrict the program to bushfire prone areas only. We consider that this roll-out achieves a reasonable balance between managing residual risk and cost; and
- *Inaccessible Meters ($2 million)* - 60% of customers supported AGN gaining access to meters when they are otherwise inaccessible on a property. We have however modified our proposal given the relatively lower customer support for this project.

Our Other Assets capex is around $40 million over the next AA period, which accounts for around 8% of our total capex (see Table 8.7).

Table 8.7: Other Assets Forecast ($2016, million)

	2018	2019	2020	2021	2022	Total
Other Assets	5.9	7.5	12.4	8.6	5.2	**39.6**

8.12. Input Cost Escalation

We have applied the AER's preferred approach to applying input cost escalation over the next AA period, as explained in Section 7 of this Draft Plan.

8.13. Overheads

Overhead costs are applied to forecast capex in order to recover general business costs that are not accounted for in the direct capex forecasts. These overhead costs include the costs associated with operations management and administration, network planning and system design, procurement and fleet, technical assurance, network engineering and other support costs such as finance and human resources.

AGN has applied the same approach used by the AER for our recent South Australian network to ensure consistency across our business. This approach involves splitting forecast overheads into fixed and variable weightings for each of our overhead categories. This results in overheads of $50 million over the next AA period.

8.14. Summary

Forecast capex for the next AA period is around $538 million, which is 5% below actual capex expected to be incurred over the current AA period (see Figure 8.1). The key driver of our capex forecast is the completion of our low pressure mains replacement program, which includes replacing mains in the city of Melbourne. Our mains replacement program is key to maintaining and improving network safety. Other key drivers of our capex program include:

- *Growth capex* – which accounts for 30% of total capex and relates to connecting new consumers to our networks; and
- *IT* – which accounts for 13% of total forecast capex and relates to the continuation of the national program of work that was initiated in the current AA period.

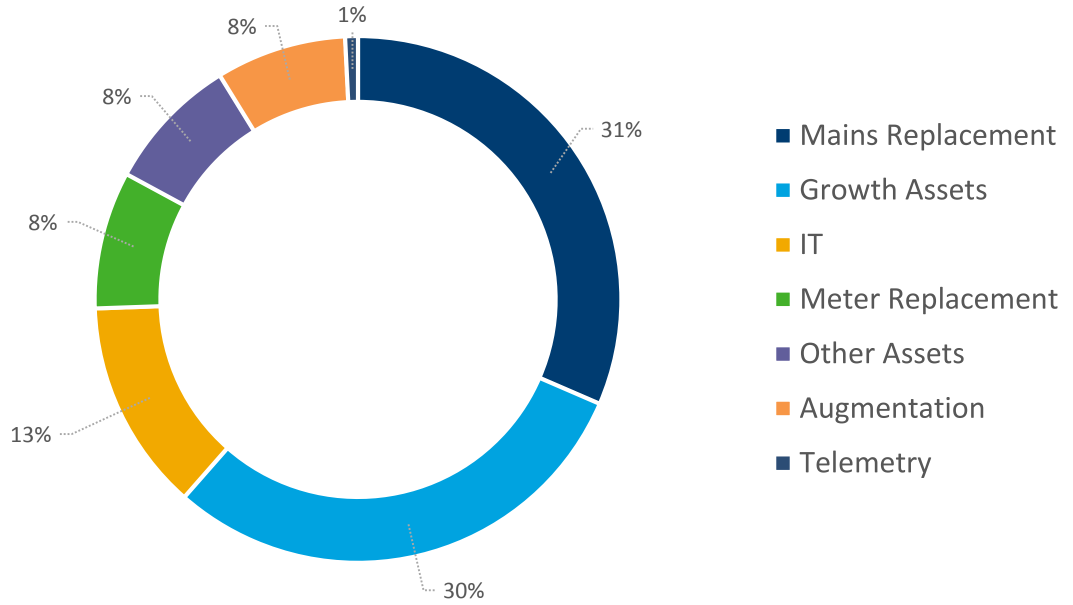
Our proposed capex is consistent with meeting our regulatory obligations and with the feedback received through our stakeholder engagement program, particularly around maintaining reliability and improving safety. Our capex forecast is set out in Table 8.8 and the composition of our program in Figure 8.4 (which is inclusive of overheads and cost escalation).

Table 8.8: Breakdown of Capex Forecast ($2016, million)

Capex Driver Category	2018	2019	2020	2021	2022	Total
Mains Replacement	36.2	36.2	36.2	34.2	8.3	**151.1**
Growth Assets	26.5	27.0	29.5	29.6	29.7	**142.3**
IT	11.3	23.8	16.1	5.1	6.0	**62.4**
Meter Replacement	8.0	8.0	8.0	8.0	8.0	**40.1**
Augmentation	5.1	9.7	11.4	7.8	4.3	**38.3**
Telemetry	0.3	1.8	1.4	0.2	0.1	**3.8**
Other Assets	5.9	7.5	12.4	8.6	5.2	**39.6**
Escalation	1.0	1.8	2.6	2.9	2.5	**10.8**
Overheads	10.0	10.3	10.4	10.0	9.4	**50.1**
Total	**104.2**	**126.0**	**128.1**	**106.5**	**73.7**	**538.5**

Note: Totals may not add due to rounding.

Figure 8.4: Composition of Forecast Capex



Stakeholder Questions

11. Do you consider we have applied an appropriate approach to forecasting capex?
12. Do you support the completion of our low pressure mains replacement program?
13. Do you support our risk assessment approach to determining the volume of mains to be replaced, including our dedicated engagement with the ESV on this issue?
14. Have we appropriately considered and incorporated the outcomes of our stakeholder engagement program?

9. Capital Base

9.1. Introduction

Our capital base reflects the value of past investments that we have made in the network, but not yet recovered from our customers. The current value of our capital base is around $1.6 billion. We are required to adjust our capital base for capex, depreciation and inflation using actual information over the current AA period and forecast information over the next AA period. This section discusses how we have made those adjustments for the current and next AA periods.

9.2. Regulatory Framework

We are required to adjust our capital base to reflect actual/forecast capex (net of any amounts contributed by our customers), inflation and depreciation. We are also required to make certain other adjustments to our capital base, such as to remove the value of any assets that we have sold or to reflect the reuse of redundant assets in the current AA period. These adjustments are however not relevant to either the current or next AA periods.

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 Section 6);
- so that our assets are depreciated over the economic life of that asset (or group of assets);
- to allow for changes in the expected economic life of a particular asset (or group of assets);
- so that an asset is depreciated only once; and
- to allow for our reasonable needs for cash flow to cover our costs.

9.3. Capital Base as at 1 January 2018

We have adjusted (or rolled-forward) our capital base as at 1 January 2013 for actual capex and inflation and for forecast depreciation over the current AA period (we have previously accepted the AER preference to use forecast depreciation when adjusting the capital base). We have used forecast information for 2016 and 2017 as actual information is not yet available.

Table 9.1 shows the adjustments we have made to our capital base over the current AA period. The “funding adjustment” in the below table reflects the interest that we did not receive as a result of actual capex in the last year of the previous AA period (i.e. 2012) being above the forecast used for that year. The closing value of the capital base forms the opening capital base for the next AA period.

Table 9.1: Roll Forward of the Regulatory Asset Base 2013 to 2017 ($nominal, million[12])

	2013	2014	2015	2016	2017
Opening Capital Base	1,154.2	1,239.9	1,334.0	1,441.4	1,512.1
Less Depreciation	41.9	46.6	52.8	57.6	61.4
Plus Conforming Capex	104.5	113.9	129.4	106.6	95.2
Plus Actual Inflation	23.1	26.8	30.8	21.7	20.1
Plus 2012 Capex Adjustments	0.0	0.0	0.0	0.0	10.7
Plus Funding Adjustment	0.0	0.0	0.0	0.0	5.2
Closing Value	**1,239.9**	**1,334.0**	**1,441.4**	**1,512.1**	**1,581.8**

Note: Totals may not add due to rounding.

9.4. Capital Base as at 31 December 2022

This section discusses the forecast adjustments made to the capital base over the next AA period.

9.4.1. Capital Expenditure

Our forecast capex was discussed in Section 8 of this Draft Plan and is reproduced in Table 9.2, 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 Section 8). This adjustment is made by the AER to account for the fact that we do not earn a return on the capex within the year it was spent.

Table 9.2: Forecast Capex for the Next AA Period ($nominal, million)

	2018	2019	2020	2021	2022
Mains and Services	74.5	81.5	89.0	85.9	51.4
Meters	14.1	14.4	15.2	16.0	17.2
Buildings	0.0	0.0	0.0	0.0	0.0
SCADA	0.3	2.1	1.7	0.3	0.2
Computer Equipment	13.5	28.7	20.1	6.7	8.4
Other Assets	7.0	9.1	15.4	11.2	7.3
Total Capex	**109.5**	**135.9**	**141.4**	**120.1**	**84.5**

Note: Totals may not add due to rounding.

12 Note: Dollars expressed in nominal terms incorporate the impact of forecast inflation.

9.4.2. Forecast Depreciation

We have continued to apply the straight line approach and asset lives that were approved by the AER for the current AA period (as shown in Table 9.3).

Table 9.3: Summary of Lives Used to Calculate Depreciation

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

In determining forecast depreciation for the next AA period, we have maintained the approach used by the AER to set depreciation in respect of forecast capex for the current AA period (which is referred to as the 'year-by-year' tracking approach). The 'year-by-year' tracking approach more closely reflects the life of the asset and was also used by the AER in its recent decisions for the Victorian electricity distributors.

We are also seeking to ensure that the value of our low pressure mains have been fully depreciated given our plans to complete our mains replacement program by the end of the next AA period (see Section 8.5). This is to ensure that the technical (or operational) life of these assets is the same as the economic life of the assets, where the former reflects the actual asset life while the latter reflects the assumption used in adjusting the capital base.

As noted earlier, forecast depreciation can be adjusted to reflect changes in the expected life of an asset. Our proposed adjustment to depreciation is consistent with other decisions made by the AER where the technical life of an asset no longer matches the economic life of the asset. For example, the AER has recently decided to adjust depreciation in respect of:

- the same low pressure mains replaced by one of the other Victorian gas distributors;[13] and
- various assets that were determined by the Victorian Bushfire Royal Commission as requiring replacement in respect of one of the Victorian electricity distributors.[14.]

We have estimated the residual value of the low pressure mains, as at 1 January 2018, to be $58 million with a remaining economic life of around 36 years.[15] We have depreciated this residual value equally over each year of the next AA period, which results in a net increase to depreciation of approximately $10 million per year. There could be an argument to further increase the rate of depreciation on the basis that:

- our low pressure mains replacement program will be largely completed by 2021 (which is year four of the next AA period, thereby implying a four year depreciation period); and

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13 AER 2012, "*Draft Decision, Multinet Access Arrangement 2013 to 2017*", Attachment 4, pg. 119, November 2012.

14 AER 2015, "*Preliminary Decision, Ausnet Services Distribution Determination 2016 to 2020*", pp. 5-13 to 5-17, October 2015.

15 The residual value was determined based on the initial low pressure mains asset value as at 1997 adjusted for inflation and depreciation, noting there was no further low pressure mains spend from this time.

- so that the value of those assets already replaced is depreciated in year one of the next AA period (2018), although there may be practical issues with this approach.

On balance, we consider a five year depreciation period achieves the objective of ensuring that the low pressure mains are fully depreciated at the time they are replaced in our network. Table 9.4 shows our forecast straight-line depreciation, which includes the adjusted depreciation of our low pressure mains.

Table 9.4: Forecast Straight-line Depreciation, 2018 to 2022 ($nominal, million)

	2018	2019	2020	2021	2022
Straight-line Depreciation	70.4	81.2	95.1	85.7	89.4

9.4.3. Inflation

Forecast inflation is a critical element in determining our total revenue (and hence prices). 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 (consistent with the adjustment for actual inflation explained in Section 9.3 to our capital base made now for the current 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 by 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 Section 10) 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 9.4) 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).

As explained in Section 13, our total revenue is used as an input (along with the forecast volume of gas used by our customers) to determine a series of “X” factors that will apply over the next AA period. These X factors allow for changes to our prices before inflation. We also escalate our prices for inflation, with the total annual adjustment to prices commonly referred to as a “CPI-X” price adjustment.

The key issue therefore arises where the forecast of inflation used to determine total revenue/prices is different to the actual inflation that is used to adjust prices under the CPI-X price adjustment process over the next AA period (noting that differences between forecast and actual inflation are corrected/accounted for when adjusting the capital base), where the former relates to assumed revenue and the latter actual revenue recovered by the business.

If inflation expectations are accurately measured, then the negative adjustment to forecast revenues made in determining regulatory depreciation has the same expected value as the positive adjustments made under the CPI-X price adjustment, such that the impact of inflation is ‘a wash’.

However, if forecast inflation is over-estimated, then the deduction for inflation made to determine regulatory depreciation is greater than the addition for inflation through the CPI-X price adjustment (and vice versa if inflation is under-estimated). This means that the business will not be provided with a reasonable opportunity to recover its efficient costs through its prices over the AA period (which means actual revenue will be below benchmark revenue).

Importantly, there is no mechanism to revisit the amount of inflation that is removed from revenues through regulatory depreciation. This has been a particular issue across our networks over recent years, where actual inflation has been well below the forecast of inflation used to set revenue/prices. For example, the most recent actual inflation used to adjust our Victorian prices for 2016 was 1.5%, which is well below the forecast of 2.5%.

The two most recent approaches to forecast inflation are the:

- *RBA-based approach* – which develops a 10 year forecast of inflation based on a combination of the Reserve Bank of Australia's (RBA's) short term forecast of inflation (for the first two years of the 10 year term) and the mid-point of the RBA's longer term target range of inflation (for the last 8 years); and
- *Market-based approach* – which develops a 10 year forecast of inflation based on the difference between yields on nominal and inflation indexed Commonwealth Government bonds with a 10 year term.

In its recent decision for our South Australian network the AER applied the RBA-based approach to derive an inflation forecast of 2.39%. Our preference was to use the market-based approach, which derived 10 year inflation forecasts of around 2.0%.

We prefer the market-based approach because it uses the same market information used to determine the rate of return, which in our view reduces the potential for forecast error. The AER however has concerns over whether the market-based approach can be relied upon to develop reliable forecasts, primarily due to concerns over the liquidity of the inflation indexed Commonwealth Government bond market.

We remain concerned that the RBA-based approach will materially overstate actual inflation over the next AA period, particularly given most recent actual inflation of 1.31% for the year to March 2016 (and five year average actual inflation of 2.0%). We note that the approach to inflation is currently subject to legal review. Like financing and tax costs, there is considerable uncertainty as to the correct approach to use to forecast inflation.

We have therefore decided to apply the most recent decision of the AER for our South Australian network of 2.39% for forecast inflation. We will continue to monitor this issue and will update our approach to forecast inflation, if required, once there is further clarity coming out of the current legal review processes.

9.4.3.1. Forecast Regulatory Depreciation

As noted, 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 9.5 shows forecast regulatory depreciation that is used to determine assumed total revenue for the next AA period.

Table 9.5: Forecast Regulatory Depreciation, 2018 to 2022 ($nominal, million)

	2018	2019	2020	2021	2022
Straight-line Depreciation	70.4	81.2	95.1	85.7	89.4
Less Inflation	37.8	39.6	41.9	44.0	45.9
Regulatory Depreciation	**32.6**	**41.6**	**53.2**	**41.7**	**43.5**

9.4.4. 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 9.6. This shows a closing capital base of $1,961 million as at 31 December 2022 in nominal dollar terms.

Table 9.6: Forecast Regulatory Asset Base 2018 to 2022 ($nominal, million)

	2018	2019	2020	2021	2022
Opening Capital Base	1,581.8	1,658.7	1,753.0	1,841.2	1,919.6
Less Depreciation	70.4	81.2	95.1	85.7	89.4
Plus Conforming Capex	109.5	135.9	141.4	120.1	84.5
Plus Actual Inflation	37.8	39.6	41.9	44.0	45.9
Closing Value	**1,658.7**	**1,753.0**	**1,841.2**	**1,919.6**	**1,960.6**

Note: Totals may not add due to rounding.

9.5. 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 completion of our low pressure mains replacement program over the next AA period. This adjustment is consistent with our obligations and recent decisions made by the AER. We have also applied the RBA-based approach to forecast inflation, although remain concerned that this approach will materially overstate actual inflation. We note however there remains ongoing uncertainty over the appropriate approach to forecast inflation.

The value of our closing capital base is $1,961 million at the end of the next AA period.

Stakeholder Questions

15. Do you agree that the value of low pressure mains should be removed from the capital base to reflect the completion of our low pressure mains replacement program? Do you agree with our proposal to depreciate these assets over five years, such that they are fully depreciated when the low pressure mains have been replaced?
16. Do you consider that the RBA-based approach will produce better forecasts of inflation relative to the market-based approach? Are there any other approaches to forecasting inflation that should be used/considered?
17. Do you have any other comments regarding our approach to adjust our capital base over the current and next AA periods?

10. Financing Costs

10.1. Introduction

Our single largest cost relates to the cost of financing our $1.6 billion investment in the Victorian and Albury natural gas distribution networks. Achieving a reasonable rate of return is essential in order to attract the necessary funding from shareholders (through equity) and debt providers to continue to invest in our networks. We are also required to estimate the cost of tax the business will incur over the next AA period.

The importance of financing and tax costs has meant that these issues have been highly contentious. There is currently, and has historically been, a large number of legal reviews relating to financing and tax costs. For example, there are currently several legal reviews relating to both of these matters, which are unlikely to be resolved for quite some time. Given this, there is considerable uncertainty regarding these costs.

As a result of the current uncertainty, and consistent with the approach we have taken elsewhere in our plan, we have decided to apply the approach most recently used by the AER for our South Australian network. We will however continue to monitor these issues and apply the outcome of the legal review process when available. This section explains further our approach to forecasting financing and tax costs.

10.2. Regulatory Framework

We are required to achieve the following objective in estimating the rate of return:

> *"…that the rate of return for a service provider is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the service provider in respect of the provision of reference services"*[16]

Our tax costs must also be estimated with reference to a specific methodology that takes into consideration our forecast taxable income, the applicable corporate tax rate and the value of imputation credits (gamma) to equity holders.

10.3. Financing Costs

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

10.3.1. Return on Equity

The return on equity reflects the return required by shareholders to invest in the network. Unlike the return on debt, it is not possible to observe the return on equity required by shareholders in the market. This means that we are required to use financial models and other market evidence to inform the estimate of the return on equity required by shareholders.

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16 National Gas Rules, r.87(3).

The AER estimates the return on equity using a "foundation model"[17], which requires the following three parameters to be estimated:

- *The risk free rate* – which measures the return an investor would expect from an asset with no risk. It is estimated based on the interest rate on Australian Commonwealth government bonds with a 10 year term measured over a 20 day averaging period prior to the commencement of the AA period;
- *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 (also assumed to be a 10 year term); and
- *Equity beta* – which measures the sensitivity of a business's returns relative to movements in the overall market returns (systematic or market risk).

For the purposes of this Draft Plan, we have applied both the AER's foundation model and most recent view on the above parameters, which results in a return on equity of 6.89% over the next AA period (see Table 10.1). These values are indicative and were measured using May 2016 information, which is the most recent actual information available prior to the release of this Draft Plan. We intend to use updated information in preparing our AA Proposal.

Table 10.1: Indicative AER Return on Equity

Parameters	AGN Indicative Proposal
Risk Free Rate (Average of interest rate on 10-year Australian government bonds over agreed averaging period)	3.53% (Using a placeholder 20 day averaging period ending on 31 May 2016)
Equity Beta	0.7
Market Risk Premium (MRP)	6.5%
Return on Equity	6.89%

10.3.2. Return on Debt

The return on debt reflects the interest rate required by debt holders on issued debt (or the interest rate on our loans). Much like the return on equity, the return on debt can be thought to comprise a base interest rate and a risk premium, in this case referred to as the debt risk premium (DRP).

Historically, and consistent with parameters in the return on equity, the return on debt was measured over a short averaging period just prior to the start of an AA period (referred to as the "on-the-day approach"). There is now general agreement that the interest rate should reflect an average over a 10 year historical period (reflecting the average length or tenor of our debt). This is commonly referred to as the trailing average approach.

[17] The AER foundation model approach is based solely on the application of the Sharpe-Lintner Capital Asset Pricing Model (SL CAPM).

The main point of difference between the AER and some electricity and gas distributors, which is the subject of the legal reviews referred to earlier, relates to whether the 10 year trailing average return on debt should apply immediately or whether there should be some form of transition to this new approach from the previous on-the-day approach (our current prices are based on the on-the-day approach). The key options under consideration are:

- *The AER approach* – which implements a 10 year transition to the trailing average approach;
- *Immediate transition approach* – no transition is applied so that the 10 year trailing average applies from the start of the AA period; and
- *A hybrid transition approach* – which implements a 10 year transition to the base interest rate component (or a proportion of the base rate component that it was efficient to hedge) but not to the debt risk premium component of the return on debt.

The above options reflect different views on how an efficient distributor would have managed risk under the previous on-the-day approach (again noting there is consensus that, on average, the length of issued debt would be 10 years). For example, support for the hybrid transition approach is based on a view that an efficient business would have entered into arrangements that locked-in (or fixed or hedged) the base interest rate over the agreed averaging period. [18]

As noted, there is currently considerable legal review into the appropriate approach for determining the return on debt. The AER has continued to apply its preferred approach, including most recently for our South Australian network. We have decided to apply a return on debt by reference to the AER preferred approach until further certainty is provided. This gives rise to a cost of debt of 5.04% over the placeholder averaging period.

We will continue to monitor this issue and will update our approach, if required, once there is further clarity coming out of the current legal review processes.

10.3.3. Rate of Return

The AER assumes that 60% of our total financing costs relate to debt with the remaining 40% relating to equity. Applying these percentages to the return on equity (6.89%) and return on debt (5.04%) results in an overall rate of return of 5.78% over the next AA period.

10.4. Cost of Tax

Our tax costs are 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.

10.4.1. Calculating the Cost of Tax

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

- *Total revenue* – which is the sum of all of our costs (or building blocks) aside from the cost of tax (see Section 13);

[18] There are also differing views on whether it should be assumed that the "benchmark efficient entity" is a regulated business (like we are) or any business.

- *Opex* – which is a specific building block that is used to determine total revenue (see Sections 7 and 13);
- *Tax depreciation* – which is based on the calculation of the tax asset base in any particular year (refer Section 10.4.3); and
- *Interest expense* – which is determined by multiplying the cost of debt (of 5.04%) by 60% of our capital base in each year, reflecting the debt funded proportion of the total capital base (see Section 9).

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 that is not elsewhere determined. The value of imputation credits (or gamma) is discussed in Section 10.4.2 below.

10.4.2. 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).

There is also uncertainty over the above parameters as a result of current legal review processes. As with the rate of return, we have decided to adopt a value for gamma of 0.4 based on the most recent decision made by the AER for our South Australian network. We will however continue to monitor this issue and update our value for gamma, if required, once the outcomes of the current legal activity are known.

10.4.3. Tax Depreciation

Tax depreciation is used to determine the estimate of taxable income and to update the value of our Tax Asset Base (TAB), as shown in Section 10.4.4. We have applied tax asset lives that are consistent with guidance provide by the Australian Tax Office (ATO).[19] We have also consolidated the TAB into a form consistent with the financial models used by the AER, as applied in the most recent decisions for the Victorian electricity distributors.

10.4.4. Tax Asset Base

The opening TAB of $698 million ($nominal) as at 1 January 2018 has been adjusted for the same forecast information used to adjust our capital base over the next AA period (see Table 10.2).

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[19] Australian Tax Office, "*TR 2015/2 - Income tax: effective life of depreciating assets (applicable from 1 July 2015)*", Table: Gas Supply (27000), pp. 161-162.

Table 10.2: Roll Forward of the Regulatory Asset Base 2013 to 2017 ($nominal, million)

	2018	2019	2020	2021	2022
Opening Tax Asset Base	697.8	765.7	868.5	965.1	1,030.8
Plus Gross Capex	109.3	135.3	140.8	119.8	84.9
Less Tax Depreciation	41.3	32.6	44.1	54.2	60.8
Closing Value	**765.7**	**868.5**	**965.1**	**1,030.8**	**1,054.9**

Note: Totals may not add due to rounding.

10.5. Summary

Our financing and tax costs collectively account for around 50% of our total costs. There is currently considerable uncertainty around the correct approach to a number of key aspects of the rate of return and gamma. Given this uncertainty, and consistent with our general approach for this Draft Plan, we have determined a rate of return and gamma by reference to the approach applied by the AER in its recent decision for our South Australian network (see Table 10.3).

We will however continue to monitor the outcomes of the current legal reviews and make any required adjustments to our proposed financing and tax costs.

Table 10.3: Indicative AER Rate of Return and Gamma

Parameters	AGN Draft Plan
Return on Equity	6.89%
Return on Debt	5.04%
Overall Rate of Return	5.78%
Gamma	0.4

Stakeholder Questions

18. Do you have any comments on our approach to setting the financing and tax costs in this Draft Plan?

11. Demand Forecasts

11.1. Introduction

This section outlines our forecasts of gas consumption and customer numbers (collectively referred to as demand forecasts) for the following customer groups:

- *Residential* – who are those customers that use gas for residential purposes;
- *Commercial* – who are our business customers who use less than 10 terajoules of gas each year (which equates to an annual retail gas bill of around $200,000 or less); and
- *Industrial* – who are our largest business customers.

Our gas demand forecasts are a key input into determining:

- *Capex* – the growth capex forecast is determined as the forecast growth in new customer connections multiplied by the relevant unit rate (see Section 8.6);
- *Opex* – opex forecasts are in part driven by the forecast growth in connection numbers multiplied by the cost per connection (see Section 7.9); and
- *Reference Tariffs* – under a price cap form of regulation, prices are determined by dividing total revenue by the demand forecasts.

We have engaged an independent expert to develop forecasts of gas consumption and customer numbers. We have applied the same methodology to develop our demand forecasts as that recently used by the AER for our South Australian network. This includes a consideration of key forecasting principles applied by the Australian Energy Market Operator (AEMO) to forecast gas demand.

11.2. Regulatory Framework

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

11.3. Forecasting Approach

We forecast the net customer growth in our network, which is determined as total (or gross) new connections less forecast disconnections. The forecast of new customer connections is used to determine growth capex (see Section 8.6), whereas the net customer growth forecast is required to determine prices.

The approach to preparing our demand forecast involves adjusting the observed (or actual) change in net customer numbers and average consumption per connection for those factors not included in the historic trend, such as for changes in retail gas prices. Our approach to forecasting gas demand is explained in this section.

11.3.1. Residential and Commercial Customers

There are around 650,000 residential and commercial customers that are currently connected to our network, accounting for over 95% of the total revenue recovered on our network. The forecast of gas demand for our residential and commercial customers is based on the following steps:

- remove the impact of weather and energy price movements from the historical average consumption of each customer group, which is then used to determine the base (or normalised) trend change in average consumption;
- adjust the historical trend consumption for any new drivers or change in existing drivers that are not included in this historic trend, such as forecast movements in energy prices (gas and electricity), the removal of zero consuming meters (if applicable) and known policy changes impacting on consumption (for example, a requirement to improve appliance efficiency);
- forecast the number of net customer connections, which is based primarily on the expected growth in new dwellings for residential customers and trend growth for commercial customers; and
- multiply average consumption per connection by connection numbers to forecast total demand for each customer group.

Although the same approach is applied, we have prepared separate forecasts of residential and commercial gas demand. This is because each customer group responds differently to the above drivers of demand.

11.3.2. Industrial Customers

While there are less than 300 industrial customers, they account for over half of the total gas demand on our network. Their demand is largely driven by prevailing economic conditions, with negligible sensitivity to variations in weather. Our industry customers are charged on a capacity basis, and as such, we forecast capacity measured as the maximum amount of gas expected to be used within a single hour (referred to as gigajoules (GJ) of Maximum Hourly Quantity (GJ MHQ)).

The key steps taken to forecast capacity for our industrial customers includes:

- identifying any known new connections, disconnections and expansions/contractions of capacity of existing customers, including through the use of surveys;
- determine those industrial customers whose demand was observed to have a statistically significant relationship with economic activity and apply an adjustment based on forecast economic growth;
- for the remaining industrial customers apply an adjustment based on historic trend changes in demand; and
- consolidate the above outputs to determine the industrial gas demand forecast.

11.3.3. Key Assumptions

The key assumptions and inputs used to forecast gas demand include our weather adjustment, forecasts of new dwelling construction (for the residential sector) and the sensitivity of demand to movements in energy prices (referred to as the price elasticity of demand).

11.3.3.1. Weather Adjustment

Gas demand for our residential and commercial customers is materially impacted by weather. This reflects that our customers use relatively more gas when it is colder to heat their homes and businesses (and vice versa in times of warmer weather). It is therefore necessary to adjust the historic residential and commercial demand for weather to ensure the forecast starting point and historic trends relied upon to forecast gas demand are not unduly impacted by abnormal weather.

We have applied the same approach to adjust for weather as that used by AEMO, which approach enables us to determine the volume impact attributable to a change in weather. This volume impact is then removed from the historic average consumption trend to derive a weather normalised trend that is used for forecasting purposes.

11.3.3.2. 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 Victoria and Albury. This forecast has relied on independent forecasts of new dwellings from the Housing Industry Association (HIA) as a basis for projecting new gas connections.

11.3.3.3. Price Elasticity

Projected retail gas and electricity prices impact on gas demand through application of a measure of own-price elasticity and cross-price elasticity, which are explained as follows:

- *Own-price elasticity* – which captures how changes in retail gas prices impacts average consumption, accounting for not only the current year impact but also the impact of price changes on consumption up to four years back (reflecting that customers will continue to respond to changes in gas prices in the years following the initial price change); and
- *Cross-price elasticity* – which captures how changes in retail electricity prices impacts average consumption, which is relevant given that gas can be substituted for electricity for all residential and most commercial applications.

In terms of the elasticity values, the forecast assumes:

- a lagged long term own-price elasticity of -0.3 for residential customers and -0.35 for commercial customers (which means a 1% increase in retail gas prices will result in a 0.3% and 0.35% decrease in average usage for residential and commercial customers respectively); and
- a long term cross-price elasticity of 0.1 (which means a 1% increase in retail electricity prices will result in a 0.1% increase in average gas consumption).

The remainder of this section presents the results of our gas demand forecasts.

11.4. Residential Forecasts

As noted, our forecasts of residential gas demand are based on forecast customer growth multiplied by forecast average consumption.

11.4.1. Residential Customer Growth

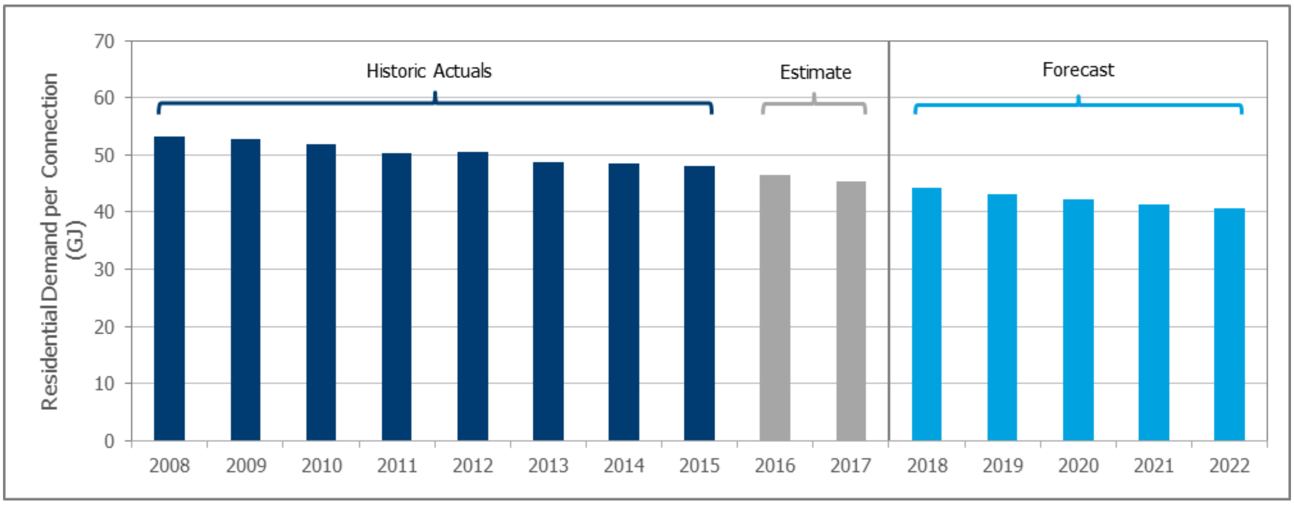
Residential net customer growth is forecast to be 1.7% per year, which is lower than the historic growth rate of 2.4%. This is due to a slowing of new dwelling construction in Victoria and Albury over the next AA period as forecast by the HIA.

11.4.2. Residential Consumption per Connection

There has been a long term decline in average residential consumption across all of our networks, including in Victoria and Albury where average consumption has fallen from approximately 54 GJ per connection in 2008 to 48 GJ in 2015 (a decline of 1.5% per annum). The key drivers of this decline include improved appliance and dwelling efficiency and the substitution of gas appliances for their electric equivalent (for example, substituting gas heating for electric reverse cycle air-conditioning).

The historic trend rate of decline in average consumption is forecast to increase to 2.4% per year, resulting in a demand per connection in the final year of the next AA period of just over 40GJ per annum (which is more than double the average consumption on our South Australian network). The forecast increase in the trend decline reflects the customer response to the increase in wholesale gas costs, which are forecast to increase by around 6% per year over the next AA period (consistent with our other networks).

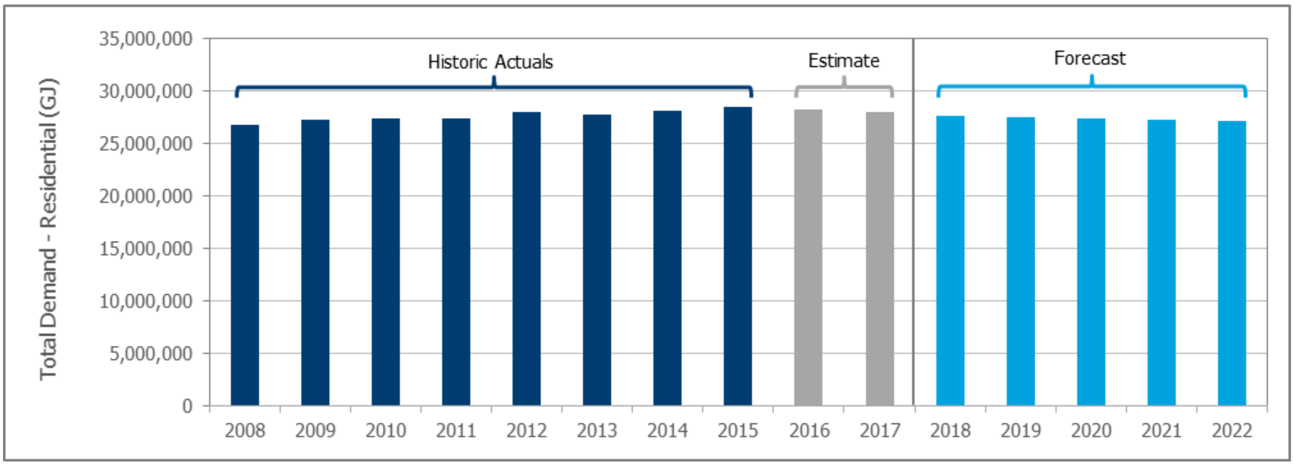
Figure 11.3: Residential Consumption per Connection (GJ)



11.4.3. Residential Demand Forecasts

Overall, residential gas demand is forecast to be relatively flat over the next AA period, with reductions in average consumption offset by net customer growth. Total residential gas demand is forecast to decrease by around 0.6% per year over the next AA period. Figure 11.4 shows the total gas demand from 2008 to 2022 (the final year of the next AA period).

Figure 11.4: Residential Demand (GJ)



The residential gas demand forecasts are shown in Table 11.1, including customer numbers, average consumption and total demand.

Table 11.1: Residential Demand Forecast

	2018	2019	2020	2021	2022
Net Customer Numbers	649,657	659,567	670,785	681,957	693,082
Consumption per Connection (GJ)	43.9	42.9	42.1	41.2	40.4
Demand (TJ)	**28,525**	**28,304**	**28,212**	**28,092**	**28,029**

Note: Totals may not add due to rounding.

11.5. Commercial Forecasts

Like residential, forecasts of commercial gas demand are based on forecast customer growth multiplied by forecast average consumption.

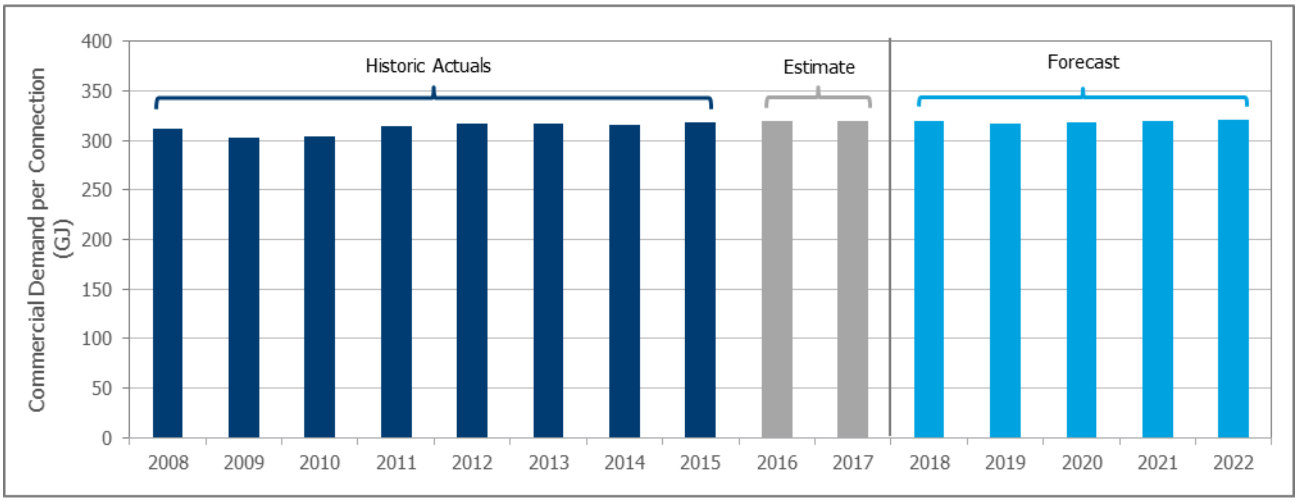
11.5.1. Commercial Customer Growth

Commercial net customer growth is forecast to be 0.5% per year over the next AA period, which is the same growth rate that has occurred over the past five years.

11.5.2. Commercial Consumption per Connection

The average consumption per commercial connection has increased by an average of 0.2% per year, from 313 GJ per connection to 319 GJ per connection between 2008 and 2015, which trend increase we have forecast to continue over the next AA period (Figure 11.6).

Figure 11.6: Commercial Consumption per Connection (GJ)



11.5.3. Commercial Demand Forecasts

We are forecasting total commercial demand to increase by 0.6% per year over the next AA period. The growth in demand is largely attributable to commercial connection growth, with consumption per connection forecast to remain relatively flat. Figure 11.5 shows the total demand from 2008 to 2022. Table 11.2 shows forecast customer numbers, consumption per connection and total gas demand.

Figure 11.5: Commercial Demand (GJ)

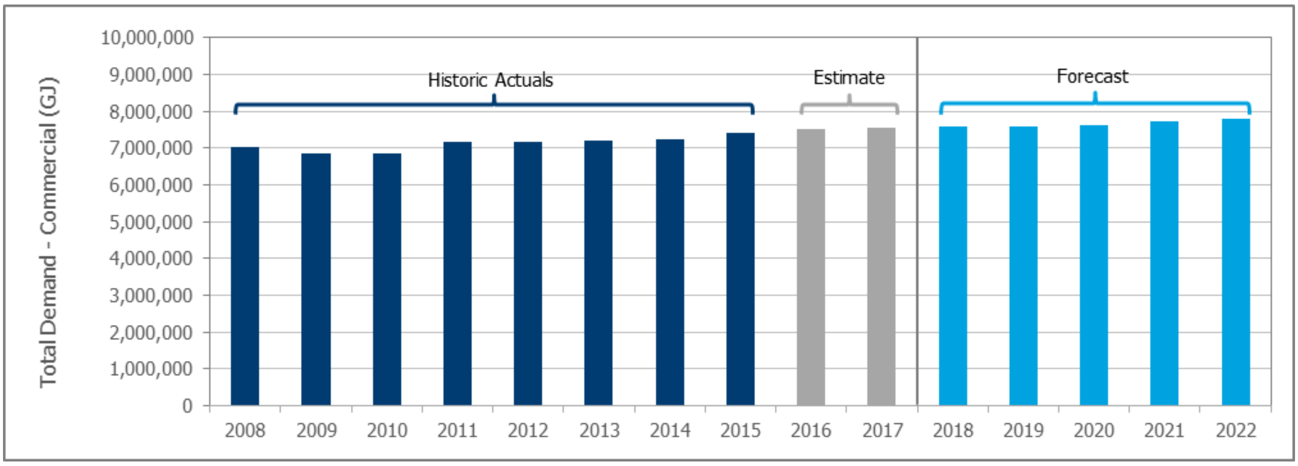


Table 11.2: Commercial Demand Forecast

	2018	2019	2020	2021	2022
Net Customer Numbers	24,724	24,874	25,024	25,174	25,324
Demand per Connection (GJ)	317.4	315.6	315.8	317.4	318.7
Demand (TJ)	**7,849**	**7,850**	**7,904**	**7,990**	**8,071**

Note: Totals may not add due to rounding.

11.6. Industrial Forecasts

Industrial demand is forecast to decline by 0.5% per year over the next AA period, from 6,446 GJ MHQ in 2018 to 6,322 GJ MHQ in 2022. The forecast trend decline in industrial demand is the same as the actual trend decline experienced over the most recent five year period (see Figure 11.7 and Table 11.3). The primary driver of the decline continues to reflect challenging economic conditions for industrial customers, particularly in the manufacturing sector.

Figure 11.7: Industrial GJ MHQ

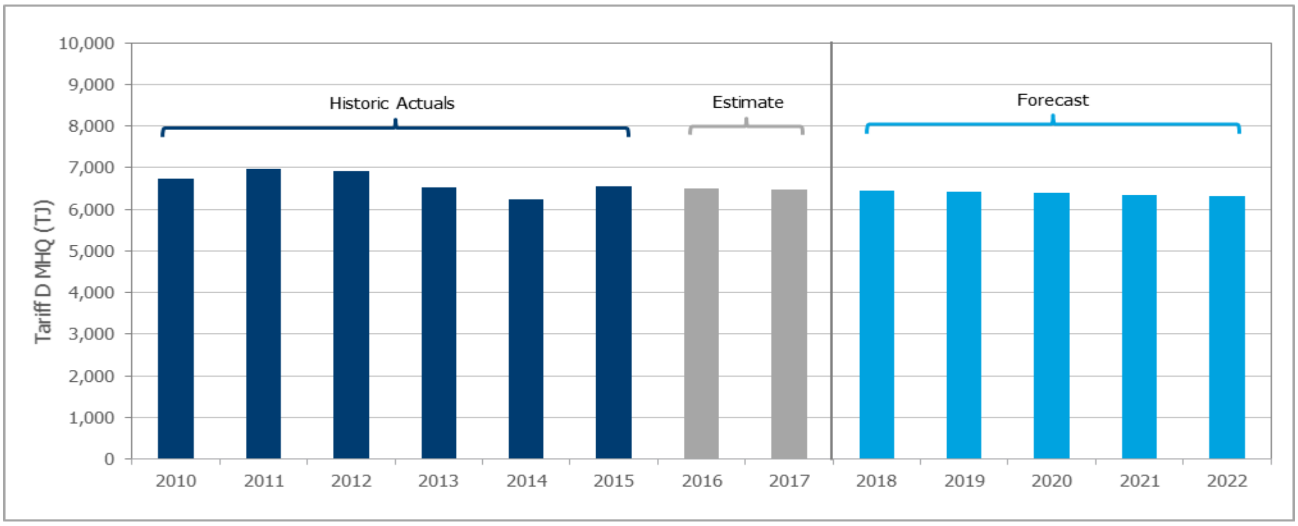


Table 11.3: Industrial GJ MHQ Forecast

	2018	2019	2020	2021	2022
GJ MHQ	6,446	6,415	6,383	6,352	6,322

11.7. Summary

Our gas demand forecasts have been based on the same methodology used by the AER for our South Australian network. The residential forecasts are driven by expected new dwellings growth in Victoria and Albury and the forecast increase in wholesale gas costs driven by the development of the gas export industry. Our commercial and industrial forecasts are largely in line with recent historic trends.

Stakeholder Questions

19. Do you consider our approach to forecasting demand to be reasonable?
20. Are there other factors we should consider in developing our demand forecast? For example, are you aware of any potential future energy policy changes that will effect gas demand over the next AA period?
21. The Victorian government recently announced a target of zero carbon dioxide emissions by the year 2050. Do you think this announcement will impact gas demand over the next AA period, and if so, how should this be factored into our demand forecasts?

12. Incentive Arrangements

12.1. Introduction

AGN is a strong supporter of effective, outcome-based incentive arrangements as a way of promoting the long term interests of our customers. Consistent with our recent South Australian AA Proposal, AGN is proposing to strengthen the incentive arrangements to apply in Victoria and Albury over the next AA period. Our proposal seeks to align the incentives that apply to gas distributors with those applying to electricity distributors in Australia.

This section explains the incentive arrangements that we consider should apply over the next AA period, including how these incentives are related to one another. This section also discusses the dedicated stakeholder engagement we are currently undertaking in addition to this Draft Plan on incentive arrangements.

12.2. Regulatory Framework

A key requirement of the NGO is for the regulatory framework to promote efficient investment in and operation of our gas distribution networks. In support of this requirement, the NGR provides that an AA may include (or the AER may require it to include) one or more incentive mechanisms to encourage efficiency in the provision of services, which includes promoting:

- efficient investment in, or in connection with, our networks;
- efficient provision of Reference Services to our customers; and
- efficient use of our network by customers.

12.3. Our South Australian Proposal

We recently proposed to strengthen the incentive arrangements that apply to our South Australian network, which included the:

- retention of the existing incentive to lower opex, which is referred to as the efficient benefit sharing scheme (EBSS), albeit modified to strengthen the financial incentive to improve opex efficiency;
- introduction of an incentive to lower capex, which is referred to as the capex sharing scheme (CESS), also modified to strengthen the financial incentives to improve capex efficiency;
- introduction of a scheme to promote improved customer service, although AGN had not developed how this scheme would work at the time of providing its AA Proposal to the AER; and
- introduction of a scheme to promote lower cost and/or improved service delivery outcomes through innovation.

Our proposed EBSS and CESS were based on the same schemes developed by the AER and applied to electricity distributors. The customer service and innovation schemes were new schemes that were based on similar schemes applied by the Office of Gas and Electricity Markets (Ofgem) in the United Kingdom.

The AER accepted the continued application of the EBSS in South Australia but did not accept any of the other proposed initiatives listed above (AGN notes that it only proposed the application of the CESS in response to the AER Draft Decision). The AER in its Final Decision recognised the potential benefits of a CESS, but decided against its introduction on the basis that:

- any changes to the incentive arrangements applying to gas require further consideration and consultation with industry; and
- there is no counterbalancing financial incentive for AGN to maintain or improve network reliability.

The CCP held similar concerns to the AER. In their response to the AER Draft Decision, the CCP noted that:

> *"Having considered the AER's [draft decision], and the counter arguments put by AGN in the [revised access arrangement proposal], [the CCP] are persuaded that the lack of standard service reliability measures and the need for additional stakeholder consultation mean that it would be premature to introduce a CESS for the next AA period."*[20]

These issues are discussed in the remainder of this section.

12.4. Industry Consultation

We understand the preference of the AER and the CCP to consult with industry on the appropriate incentive arrangements for gas distributors. We are however keen to ensure this consultation occurs prior to the release of the AER Final Decision for Victoria and Albury. We have therefore committed to this additional consultation through both this Draft Plan and a dedicated stakeholder engagement process with the other two Victorian distributors (Multinet Gas and AusNet Services).

The three Victorian gas distributors have recently published an Issues Paper that explores the potential strengthening of the incentive framework to apply in the next AA period (the paper covers similar issues to that discussed in this Draft Plan). The Issues Paper is available at our stakeholder engagement website (http://stakeholders.agnl.com.au). We are seeking submissions on the Issues Paper by 29 July 2016.

We are also holding a deliberative stakeholder workshop on the Issues Paper. The aim of the workshop, which will be held on 11 July 2016, is to discuss with and receive feedback from key stakeholders on the appropriate incentive arrangements to apply to gas distributors. We have engaged an independent expert to facilitate the workshop and to capture and report on the feedback received from stakeholders.

We will then provide to the AER the feedback from the workshop and submissions to the Issues Paper. AGN will also provide the feedback regarding incentive arrangements received on this Draft Plan. This feedback will be an important input into the types of incentive arrangements that will apply in the next AA period. We will then work with the AER on further engagement regarding the specific design of any incentive schemes that are to apply.

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[20] Consumer Challenge Panel – "*Supplementary advice to AER from Consumer Challenge Panel sub-panel 8 – AGN*"- 31 March 2016 pg. 5.

12.4.1. Network Reliability Incentive

We agree with the AER that the introduction of a CESS would preferably be accompanied by a counterbalancing financial incentive on network reliability and service. This matter is discussed further in Section 12.6.3.

12.5. Current Incentive Arrangements

The incentives that apply to electricity distributors are significantly stronger than those currently applying to gas distributors.

12.5.1. Gas Distribution Incentive Arrangements

The AER currently only applies its EBSS to gas distributors in Victoria. The CESS currently does not apply in Victoria, despite a similar capex incentive scheme applying previously in Victoria. There is also a Guaranteed Service Level (GSL) scheme in Victoria, which provides direct compensation to those customers receiving service levels below pre-defined thresholds. Those aspects of service included in the GSL scheme include:

- customers who experience five or more unplanned interruptions within a calendar year;
- customers who experience an interruption lasting greater than 12 hours;
- the number of appointments not attended to by AGN within two hours of the scheduled time; and
- the number of connections not made within one day of the agreed time.

We support the continued application of the GSL scheme, but note its purpose is to directly compensate customers rather than driving improvements in service for all customers across the network. The financial impact of the GSL scheme is also not consistent with the objective of providing an appropriate counterbalance to the CESS.

12.5.2. Electricity Distribution Incentive Arrangements

The AER currently applies both the EBSS and CESS to electricity distributors. The AER also applies a:

- *Service Target Performance Incentive Scheme (STPIS)* – which provides for revenue to increase or decrease by up to 5% of average annual revenue depending on performance in respect of certain reliability and customer service measures; and
- *Demand Management Incentive Scheme (DMIS)* – which provides an incentive on electricity distributors to manage peak demand on the network and is generally funded through opex.

Jurisdictional GSL schemes also apply to electricity distributors. The GSL scheme applied to Victorian electricity distributors is consistent with that currently applying to AGN.

12.6. Proposed Incentive Arrangements

Our view is that the incentive arrangements should be designed to:

- balance the incentives to choose the most efficient mix of opex and capex;
- balance the incentives to reduce opex and capex against the incentive to maintain or improve service quality; and

- ensure there are sufficient incentives to invest in innovation (or provide better ways to provide services).

This section discusses our proposed incentive arrangements to apply over the next AA period having regard to the above objectives.

12.6.1. Efficiency Benefit Sharing Scheme

We consider that the EBSS is a well-designed scheme that provides continuous incentives for distributors to decrease opex. We also note the AER has applied the EBSS across all of our regulated networks, including in Victoria and most recently in South Australia. We therefore propose that the EBSS continue to apply over the next AA period and consider this to be non-controversial.

We are however considering an increase in the incentive powers of the EBSS, which is discussed in Section 12.6.4.

12.6.2. Capital Expenditure Sharing Scheme

There seems to be a general consensus over the potential benefits of a CESS. For example, as part of the process to change the National Electricity Rules, the Australian Energy Market Commission noted that:

> *"The Commission identified the following benefits with capex sharing schemes in the draft rule determination:*
>
> - *they encourage appropriate network investment;*
> - *they encourage NSPs [Network Service Providers] to look for efficiencies, such as by innovation;*
> - *they provide an incentive for NSPs to reveal their efficient costs; and*
> - *they can be designed to provide for a continuous incentive, that is, the incentives could be set so that the incentive power is the same no matter in which year of a regulatory control period an investment is made."* [21]

Likewise, the CCP in their advice to the AER in respect of our proposal for South Australia noted:

> *"We consider the EBSS and the CESS work together to ensure that there is no bias towards one form of expenditure over another."*[22]

We agree with the above, and as such, propose that a CESS apply over the next AA period. This is primarily because a CESS is required to balance the incentives already provided to opex through the EBSS with the incentives to incur efficient capex. The CESS provides a continuous and symmetrical incentive to ensure the lowest sustainable mix of capex and opex is incurred by the distributor in each year of the next AA period.

We propose that the same CESS currently applying to electricity distributors should also apply to gas distributors. This is because, consistent with our views on the EBSS, the CESS is a well-designed incentive scheme. The AER CESS has the following key attributes:

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[21] AEMC 2012, "*Economic Regulation of Network Service Providers, and Price and Revenue Regulation of Gas Services, Final Position Paper*", November 2012, pg. 121.

[22] Consumer Challenge Panel subpanel 8, *"Advice to AER from CCP8 regarding AGN's (SA) Access Arrangement 2016-21"*, August 2015, pg. 15.

- the scheme provides for the same reward and penalty, which is determined as the difference between actual and benchmark capex over an AA period;
    - the calculated CESS amount would then be added as a building block in the determination of Total Revenue for the subsequent (2023 to 2027) AA period (in the same way the EBSS is now a building block in determining our Total Revenue for the current and next AA periods);
- like the EBSS, the CESS is designed such that the business retains 30% of the reward/penalty (and therefore removes any incentive to favour capex over opex);
- there are no exclusions (aside from capex allowed under an approved pass-through application); and
- the CESS will be adjusted if the AER deems a material amount of capex has been inefficiently deferred into the next AA period.

12.6.3. Service Target Performance Incentive Scheme

The AER in its Final Decision for our South Australian network emphasized the importance of considering the interrelationships between incentive arrangements:

> *"Incentive mechanisms do not operate in isolation. They must work in conjunction with the existing incentives provided to the service provider, both under the access arrangement and more generally. Where an incentive mechanism does not do this, it may in fact incentivise inefficient or imprudent behaviour by a service provider, to the detriment of the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.*
>
> *... to contribute to the NGO and be consistent with the RPPs [Revenue and Pricing Principles], an incentive scheme must maintain balance between competing incentives under the access arrangement. For example, a CESS could strengthen incentives to outperform approved capex forecasts, and balance a service provider's incentives to do so across the access arrangement period. As a complement to the opex efficiency carryover mechanisms that have applied in gas for some time, it can also balance incentives to choose capex solutions over opex to maximise carryover amounts under the ECM.*
>
> *However, without a complementary incentive to maintain the quality, safety, reliability and security of supply of natural gas, a CESS may create financial incentives for service providers to reduce capex in a way that could put the safe and reliable operation of the network at risk."* [23]

A key reason for the AER not accepting the CESS in South Australia was the lack of a counterbalancing incentive on network service:

[23] AER, "*Australian Gas Networks South Australian Access Arrangement 2016 to 2021*", Final Decision, May 2016, pp. 14-8 to 14-9.

> *"We recognise the potential benefits of a CESS. However, as discussed above we remain concerned that the addition of a CESS to AGN's access arrangement has the potential to create an overall imbalance in incentives under its access arrangement. This could undermine incentives for efficient investment in AGN's network, and potentially incentivise underinvestment. Such an outcome would not promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas. We consider these issues require further consideration and consultation to ensure the suitability of the scheme for gas."*[24]

We agree with these views and propose that a gas equivalent to the electricity STPIS should accompany the introduction of a CESS. This requires a consideration of appropriate measures of reliability and customer service to include in a gas STPIS.

Unlike electricity, reliability levels for gas distribution are at very high levels (reflecting that the majority of our assets are underground). On average, our customers can expect one unplanned interruption to their gas supply of less than one hour every 40 years. Measures of the frequency and duration of supply interruptions are therefore not necessarily appropriate for the purpose of providing an appropriate counterbalance to the CESS under a gas STPIS.

Our view is that measures pertaining to the safe supply of natural gas are more suitable measures to include in a gas STPIS. The provision of a safe and reliable supply of natural gas is central to our obligations, and as such, is the most important driver of business performance. Our key strategy to maintain public safety relates to managing gas leaks on our network. Our key obligations in this regard include:

- the maintenance of a 24-hour, seven day a week facility for the public reporting of natural gas leaks;
- setting the time for the repair of a natural gas leak, which time depends on the severity or risk associated with the leak; and
- setting the time periods for undertaking routine surveys of mains to check for natural gas leaks.

We consider that these types of measures are most suited to a gas STPIS, along with measures of customer service. There is the additional benefit that we already report to the ESV our performance against these measures. This allows the targets included in the gas STPIS to be informed by a long time series of historic data.

Based on the above, we believe that the following network customer service performance measures could be included into a gas STPIS:

- *Time taken to respond to a publicly reported gas leak* – specifically the percentage of publicly reported leaks responded to by a gas distributor within two hours;
- *Time taken to repair a publicly reported leak* – with a focus on those gas leaks that pose the greatest threat to public safety; and
- *Time taken to answer a customer call/enquiry* – which measures could relate to our emergency call center and/or our general customer call center.

[24] Ibid., pg. 14-14.

We believe that the above measures could form the basis of a gas STPIS on the basis that they capture the key elements of network safety and customer service performance for gas distributors. In addition to the types of measures, decisions will need to be made on the strength of the financial incentives attached to each measure included in the STPIS.

We consider that the strength of the gas STPIS could initially be set at the lower bound of incentives provided for electricity distributors to provide stakeholders with sufficient confidence in the scheme before strengthening the incentives in subsequent periods. This would result in a STPIS being set to provide for rewards and penalties of around 2.5% of total revenue (which in our case is around $5 million per year).

These matters will however need to be put to further stakeholder engagement as part of the dedicated engagement stream described earlier if a decision is made to introduce a gas STPIS for the next AA period.

12.6.4. Determining Incentive Power

The current EBSS and CESS is designed such that the distributor retains around 30% of an efficiency gain or loss and customers the remaining 70%. This sharing ratio has not changed since 2003 when opex and capex incentive schemes were first applied to our networks. We consider it is now timely to consider increasing the power of the incentives given the maturity of the incentive schemes. The key reasons for considering an increase in incentive power include that:

- there is evidence suggesting that the rate of productivity growth for the Victorian gas distributors is converging on the long run rate of technological change; and
- there is also evidence that the current incentives for distributors to improve productivity are relatively low.

With regard to the first point, and as shown in Section 3.2, the change in productivity levels was relatively high between 1999 and 2005 and relatively low thereafter. This is true for AGN on its own, the three Victorian gas distributors grouped together and for the industry as a whole. More specifically, for:

- *AGN* – productivity levels increased by 3.4% between 1999 and 2005 and by 0.4% from 2006 to 2015;
- *Victorian Gas Distributors* – productivity levels increased by 2.4% between 1999 and 2005 and by 0.5% from 2006 to 2015; and
- *All Gas Distributors* – productivity levels increased by 1.9% between 1999 and 2005 and by 0.9% from 2006 to 2015.

With regard to the second point, there is evidence suggesting that the current regulatory regime provides relatively weak incentives for gas distributors to improve productivity. This is of concern given the above evidence suggesting that we are currently operating at the productivity frontier of the industry in Australia, making future productivity gains harder and more costly to achieve. This may explain the relatively lower rates of productivity growth in more recent years.

The relatively mature nature of the industry was a key driver for increasing incentive rates for gas distributors in the United Kingdom. The equivalent opex and capex incentives in the United Kingdom allow distributors to retain up to 70% of any increase or decrease in productivity. In doing so, the regulator acknowledged that there is no exact science to determine optimal incentive rates, and as such, judgement is required.

We consider that equal (or 50%) sharing of a efficiency gain with our customers would provide an appropriate balance between encouraging further improvements in productivity and the retention of any associated benefits retained by customers. This sharing ratio could be considered to be conservative when compared to similar schemes operating in the United Kingdom.

12.6.5. Network Innovation Scheme

The incentive for a regulated business to invest in innovation is different to an unregulated business. This relates to the periodic resetting of costs (and prices) for a regulated business at five yearly intervals. This might result in an inability for the regulated business to retain the benefit of that innovation for a sufficient period of time to offset the cost of that innovation. This is particularly the case where:

- an allowance for innovation is not included in the allowed opex and capex benchmarks;
- revenue/prices are reset shortly after the innovation (such that the benefits of that innovation are also passed through to customers after a short period); and
- an EBSS and/or CESS apply (such that the distributor will incur a penalty resulting from the investment in innovation for a period of five years).

The above suggests that the scope/incentive for a regulated business to invest in innovation can be limited. This limits the potential benefits of innovation to the distributor to an (unlikely) maximum of five years. There is the (likely) potential, however, that the costs and risks associated with spending on innovation may require a longer payback period, particularly in light of the potential size of the investments required for gas pipelines.

The consequence of the above is that otherwise beneficial innovations are not pursued, or only those innovations that are low cost and have a shorter payback period are investigated and implemented. This outcome is not in the long term interests of consumers, and as such, does not lead to outcomes that promote the NGO. We therefore consider that a scheme that facilitates investment in innovation should apply to gas distributors.

This scheme is similar in its intent to the DMIS discussed earlier, which scheme allows electricity distributors to seek additional funding (generally through opex) to manage peak demand on the network instead of investing in network augmentation. The electricity distributors apply to the AER for amounts up to $1 million per year to invest on demand management (but only recover the amount they spend). Our proposed network innovation scheme would operate in a similar manner to the DMIS.

12.7. Summary

We consider the incentive arrangements that apply to gas distributors over the next AA period should be strengthened. In addition to this Draft Plan, we are undertaking dedicated stakeholder engagement on incentive arrangements with the other two Victorian gas distributors, with submissions due on our Issues Paper by 29 July 2016. The focus of this engagement is on the merits of strengthening incentive arrangements rather than their detailed design.

Our proposal seeks to align the incentives that apply to gas distributors with those applying to electricity distributors. Our proposal considers the feedback received as part of the recent AA review for our South Australian network, particularly around the need to consider the interrelationships between difference incentive schemes. Specifically, we are proposing to:

- *Retain the existing EBSS* – which provides continuous incentives to lower opex;

- *Re-introduce a CESS* – which provides continuous incentives to lower capex and provides a counterbalancing incentive to the EBSS;
- *Introduce a STPIS* – which provides continuous incentives to improve network and customer service and provides a counterbalancing incentive to the EBSS and CESS; and
- *Introduce a network innovation scheme* – which will facilitate improved investment in network innovation.

We are also considering the merits of proposing to strengthen the power of the above EBSS and CESS, and as such, are seeking feedback on this matter.

Stakeholder Questions

22. Do you support the objective of strengthening the incentives that apply to gas distributors? If so, should the incentive arrangements be consistent with that provided to electricity distributors?
23. What factors should be considered in informing a decision over the appropriate incentives to apply to gas distributors?
24. Do you agree that the EBSS should be retained?
25. Do you agree that a CESS should be re-introduced, including to provide a counterbalance to the EBSS?
26. Should the introduction of a CESS be accompanied by a counterbalancing STPIS? What types of measures should be included in a STPIS?
27. Do you support the introduction of a network innovation scheme aimed at better facilitating innovation or are the current arrangements sufficient? What level of allowance should be allowed under any proposed innovation scheme?
28. Do you think there is sufficient evidence to support increasing the incentive power of the EBSS and CESS?

13. Network Revenue and Pricing

13.1. Introduction

This Draft Plan has described the services we will provide (Section 6) and the cost of providing those services (Sections 7 to 10). Our costs are referred to as 'building blocks' and are summed to determine total revenue (referred to as building block total revenue) in each year of the next AA period. We recover this revenue through the prices (or tariffs) that we charge retailers for providing services.

This section sets out the total revenue and the proposed prices to apply over the next AA period, including our proposal to align prices on our Victorian and Albury networks.

13.2. Regulatory Framework

We are required to determine total revenue for each year of the next AA period as the sum of our forecast opex (Section 7), return on our capital base (Sections 8, 9 and 10), depreciation of the capital base (Section 9) and a forecast of the cost of tax (Section 10). Our total revenue can also increase or decrease depending on our performance against the EBSS that applied in the current AA period.

Our prices are required to reflect, to the extent possible, the underlying cost of providing services to our customers.

13.3. Revenue

This Draft Plan has set out the derivation 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 ARS is provided in Table 13.1. We have separated HRS and ARS because there are different prices that apply to these services.

Table 13.1: Building Block Total Revenue, 2018 to 2022 ($nominal, million)

	2018	2019	2020	2021	2022
Return on Capital	91.4	95.9	101.3	106.4	111.0
Return of Capital	32.6	41.6	53.2	41.7	43.5
Opex	62.0	64.2	66.5	69.0	71.7
Incentive Mechanism	18.4	13.5	11.9	6.7	0.0
Cost of Tax	8.2	12.7	13.6	9.8	9.7
Building Block Total Revenue (including ARS)	**212.6**	**227.8**	**246.5**	**233.7**	**235.8**
Less ARS	4.1	4.3	4.4	4.5	4.7
Building Block Total Revenue (excluding ARS)	**208.5**	**223.5**	**242.1**	**229.1**	**231.2**

Note: Totals may not add due to rounding.

We recover the building block revenue through the prices we charge retailers for providing services. We are required to set our prices such that the total revenue we recover through prices is the same as the building block total revenue (put differently, so that we are no better or worse off if we recover the building block revenue or the actual revenue we recover from our prices). There are a series of percentage changes (or X factors) to ensure this objective is achieved.

The building block total revenue, price revenue and required percentage changes in prices are set out in Table 13.2. We have developed our price path in order to:

- provide for revenue growth that, to the extent possible, matches the growth in the capital base over the next AA period to ensure our revenue grows in-line with our underlying costs; and
- to equate revenue with our underlying costs in 2022 (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 January 2023 to equate price revenue with costs.

The first point is also consistent with assisting the business maintain/achieve stable credit metrics at levels assumed by the AER in setting the return on debt (see Section 13.3.1).

Table 13.2: Proposed Price Path, 2018 to 2022 ($nominal, million)

	2018	2019	2020	2021	2022
Building Block Revenue	208.5	223.5	242.12	229.1	231.2
Price Revenue	203.3	214.3	226.8	240.0	254.2
Real Price Path	11.0%	-3.1%	-3.1%	-3.1%	-3.1%

13.3.1. Financeability of a Pricing Decision

The AER assumes a certain credit rating (of BBB+/Baa1) when it sets the return on debt (as the assumed credit rating directly impacts borrowing costs/rates). We therefore consider that it is good regulatory practice for the AER to consider the overall outcome of its decision in light of this important assumption. We note that this type of analysis is undertaken by other regulatory bodies, including by the Office of Gas and Electricity Markets in the United Kingdom.

Specifically, we believe that the AER should consider whether its decision provides sufficient revenue/cash flow for a business to achieve the assumed credit rating. The credit rating agencies focus on the following two key ratios in making a decision on an appropriate 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).

FFO is calculated as total 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. We also consider that the key focus of the credit rating agencies is on the FFO to debt ratio given the prevailing very low interest rate environment (making interest coverage a far easier constraint to achieve).

We have assessed the key credit ratios delivered by our Draft Plan (see Table 13.3). This shows that an average FFO to debt of 8% and FFO-to-interest of 2.6 over the next AA period. While average FFO to debt is below the 9% threshold required for a BBB+/Baa1 rating, the ratio is increasing over the next AA period. This reflects and supports our proposed price path explained in the previous section of this Draft Plan.

Table 13.3: Draft Plan Key Credit Ratios, 2018 to 2022

	2018	2019	2020	2021	2022	Average
FFO to Debt	6.9%	7.0%	7.3%	8.8%	9.8%	8.0%
FFO to Interest Cover	2.4	2.4	2.5	2.7	2.9	2.6

The credit ratios are however at best marginal, and as such, should be monitored closely as part of the decision making process. For example, the above ratios are aided by the change in depreciation of the remaining low pressure mains that are included in the capital base (see Section 9.4.2). The FFO to debt credit ratio would drop to an average of 7% in the absence of this change in depreciation initiative.

At this level, our view is that an adjustment to our cash flow would be required over the next AA period to maintain the credit rating assumed by the AER in setting the return on debt. Such an adjustment could include to:

- vary the inflation adjustment that is applied to our capital base, with the lower inflation adjustment provided through increased revenue (and hence cash flow) in the next AA period; or
- shift the classification of capex to opex, which again increases the cash flow given that opex is recovered in the year it is incurred while capex is recovered over the longer term (up to 60 years).

Importantly, any such adjustment alters the timing of cash flow rather than the total amount of cash flow recovered by our business (that is, consumers are no better or worse off as a result of the adjustment over the medium to longer term).

13.4. Prices

As already noted, we recover our revenue through the prices that we charge retailers for providing services. This section outlines our current pricing structures and our proposed changes to those prices.

13.4.1. Current Pricing Structure

The current pricing structures have been in place since 2013 and are shown in Table 13.4. There are four different pricing zones in Victoria (Central, Northern, Murray Valley and Bairnsdale) and one additional pricing zone in Albury (which we are required to maintain).[25] Each zone comprises residential, commercial and industrial prices.

[25] In November 2015, AGN applied to consolidate the Victorian and Albury Access Arrangements and on 23 March 2016 the AER directed AGN to do so. As a condition of this consolidation, the AER specified that Albury remain a separate tariff zone under the combined access arrangement for the next access arrangement period.

Prices for residential and commercial customers consist of a number of volumetric (or consumption) based charging parameters (in dollars per GJ per day) and a fixed supply charge (in dollars per day). Prices for our industrial customers are capacity based and consist of a number of banded charging parameters (in dollars per GJ of MHQ). All prices decline as usage increases to promote better network utilisation.

Table 13.4: Charging Parameters by Customer Type

Residential (Tariff R)	Commercial (Tariff C)	Industrial (Tariff D)
Fixed Charge	Fixed Charge	0 – 10 GJ MHQ
0–10 GJ	0-18 GJ	Next 40 GJ MHQ
10–18 GJ	18-201 GJ	Additional GJ MHQ
>18 GJ	201-500 GJ	
	>500 GJ	

13.4.2. Stakeholder Engagement

Our pricing structures have so far been a key component of our stakeholder engagement program. This has included through our:

- *Customer workshops* – where we engaged on whether our customers prefer fixed or variable prices (see Section 5.5.2); and
- *Retailer Reference Group (RRG)* – where we tested specific elements of our current pricing structure with retailers who supply the Victorian and Albury markets.

In respect of the customer workshops, three-quarters (74%) of participants supported a high to very high degree of variability in their gas bill in-line with their gas usage. This is consistent with our current pricing structures, where around 75% and 94% of the average customer distribution charge is variable for residential commercial customers respectively.

The RRG indicated an overall preference for simplicity so that our prices are easily understood and avoid unnecessary costs to administer. Specifically, the RRG:

- sought pricing alignment of the four Victorian pricing zones; and
- indicated a preference to remove the declining pricing bands in favour of a single pricing band.

13.4.3. Pricing Alignment of the Victorian Pricing Zones

We have considered the implication of aligning the prices that we charge in each of the four Victorian zones. We consider that alignment across the three largest and most mature zones of Central, Northern and Murray Valley has merit. We are still considering our position in regards to our prices in Bairnsdale, as this relatively recent extension was approved on the basis of a premium tariff.

We have considered the impact on customers of aligning the prices that we charge across the three zones. We have aligned the residential and commercial prices so that the revenue recovered under the current and revised prices is the same. We have used the forecast average consumption for 2018 (see Section 11) for all residential (44 GJ) and commercial (317 GJ) customers across all zones (although the actual impact will depend on actual customer usage).

Table 13.5 shows the changes in our network charges if the same price was applied across the three zones in the next AA period. The effect of applying the same price, which includes our proposed overall price cut of 11%, is that our network charge will fall in all zones aside from customers in the Northern zone. The increase for customers in the Northern zone is however small, at $1.00 and $17.70 per year for residential and commercial customers respectively.

We therefore support the proposal by the RRG to align prices across the three Victorian zones of Central, Northern and Murray Valley. We consider this structure is simpler, and as such, will reduce transaction costs. We will consider further whether this alignment should also be applied to Bairnsdale.

Table 13.5: Average Customer Impact of Proposed Single Victorian Tariff

Average Customer Impact of Proposed Single Tariff	2017 Average Annual Charge ($)	2018 Average Annual Charge ($)	Variance ($)	Variance (%)
Residential				
Central	337.9	304.1	(33.8)	(10.0%)
Northern	303.1	304.1	1.0	0.3%
Murray Valley	314.3	304.1	(10.1)	(3.2%)
Commercial				
Central	1,328.7	1,195.3	(133.4)	(10.0%)
Northern	1,177.6	1,195.3	17.7	1.5%
Murray Valley	1,330.0	1,195.3	(134.6)	(10.1%)

13.4.3.1. Consolidation of Pricing Bands

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 (see Section 11).

We therefore consider there is strong merit in retaining the existing declining pricing structure and propose that it be retained. We consider our pricing structures align with our obligations that require AGN to promote the efficient use of the network.

Whilst we do not consider the number of bands to be overly complex, we did consider consolidating the first two commercial price bands to simplify the tariff structure. We have however decided against this option on the basis that this would result in a significant difference in network charges between residential and commercial users of the same size, which is not consistent with our underlying costs.

13.5. Summary

We recover our costs, or building block revenue, through the prices that we charge for providing network services. We have proposed to cut our network prices in Victoria and Albury by 11% (before inflation) on 1 January 2018 and increase prices thereafter in-line with the growth in our capital base. This price path materially improves our ability to maintain stable credit metrics at levels assumed by the AER in setting our cost of debt allowance.

We consider that it is good regulatory practice to assess our plan (and subsequent AER decisions) to ensure that it delivers sufficient cash flows to maintain the BBB+/Baa1 credit rating assumed by the AER in setting the return on debt. We have done this and consider that there is some risk that the cash flows under this Draft Plan are not sufficient to maintain the assumed credit rating. We consider this analysis needs to be updated by the AER through the review of our AA proposal.

We propose to align our prices across three of our Victorian zones. We believe this will result in a simpler pricing structure and note that most customers will continue to receive a reduction in network charges as a result of our proposed plans. We do not however consider we should consolidate pricing bands, primarily as the declining pricing structure encourages better and more efficient use of the network.

Stakeholder Questions

29. Do you support our objectives of maintaining stable credit metrics and aligning revenue with underlying costs in setting our proposed price path? Would you prefer an alternate price path, and if so, on what basis?
30. Do you consider that explicit consideration should be given as to whether a pricing proposal provides sufficient cash flow to maintain the credit rating assumed by the AER in setting the cost of debt? If so, how do you think this assessment should be done – for example, by considering the credit metrics against levels assumed by ratings agencies? If an adjustment to prices is required, how should this be undertaken – for example, through changes in capitalisation or depreciation?
31. Do you consider that there is an appropriate split between our fixed and variable charges?
32. Do you agree with our proposed pricing structures, including our decision to align prices across the three Victorian zones of Central, Northern and Murray Valley and our decision not to consolidate price bands?

14. Next Steps

This Draft Plan has explained our preliminary views on the services we will offer, the costs we expect to incur and the prices we propose to charge over the next AA period. The Draft Plan therefore provides stakeholders with an important opportunity to provide feedback on our plans before we prepare our AA Proposal.

We consider that effective stakeholder engagement is vital to achieving our objective of submitting a plan to the AER that is capable of being accepted. We therefore encourage our customers and stakeholders to provide feedback on this Draft Plan. Your feedback will help AGN finalise the details of our Victorian and Albury AA Proposal, ensuring it is a plan that best promotes the long term interests of our customers over the next AA period.

We intend to publish your submissions on our stakeholder engagement website, which can be found at http://www.stakeholders.agnl.com.au.

14.1. Making a Submission

We have highlighted particular questions throughout this document that we are seeking feedback on (a consolidated list of questions is also provided at the end of this section). Importantly, we are seeking feedback on any aspects of our proposed price and services and not just those questions listed below and throughout this Draft Plan.

You can provide your feedback on AGN's Draft Plan through the following options:

- *Online* – visit http://stakeholders.agnl.com.au/have-your-say/ to lodge your feedback online;
- *Email* – send your feedback to haveyoursay@agnl.com.au;
- *Post* – send your submission to:

  Craig de Laine (General Manager Regulation)
  Australian Gas Networks
  Level 6, 400 King William St
  ADELAIDE SA 5000

- *In Person* – feel free to contact us at haveyoursay@agnl.com.au to arrange a time to discuss your feedback in person.

14.2. Due Date

We would appreciate if you could provide your submission to AGN by Tuesday 16 August 2016. This will ensure we have sufficient time to respond to the issues raised in your submission prior to finalising our AA Proposal.

14.3. Your Consent

We intend to make your submission publicly available on our stakeholder engagement website. This information may therefore be referred to by AGN or other stakeholders throughout the review of our AA Proposal (including by having AGN and other stakeholders refer to the material in their written submissions).

Your consent will continue until you inform us that you want to withdraw it. If you withdraw consent after we have published a report which includes information you have provided, your consent will not be able to be withdrawn in respect of that published report. You can state in your submission how you would like your input to be referenced.

14.4. Confidentiality

You may indicate in writing that you prefer all or any part of your submission to be treated as confidential. Where a submission contains only some confidential or commercially sensitive information, you may consider providing a public version of the submission with a clear indication of where the confidential information is included.

The AER's Confidentiality Guideline[26] provides guidance on how it treats confidentiality claims, including those contained in regulatory proposals. The AER seeks to balance commercial confidentiality with disclosing information to create an open and transparent regulatory environment.

We consider that the AER Confidentiality Guideline provides appropriate guidance for the treatment of confidentiality claims for the purpose of responding to this Draft Plan.

14.5. Privacy

We are committed to protecting the privacy of any personal information we collect from you. Unless you give us your consent to do otherwise, we will only collect, use and disclose your personal information in accordance with our privacy policy, which is available at: http://stakeholders.agnl.com.au/privacy-statement.

[26] AER, Confidentiality Guideline November 2013, https://www.aer.gov.au/system/files/AER%20Confidentiality%20guideline%20-%20November%202013.pdf.

Stakeholder Questions

1. Do you have any feedback on our targets for the next AA period, including whether our targets are consistent with feedback received from our stakeholder engagement program?
2. Do you have any comments on the structure or implementation of our stakeholder engagement program?
3. Do you have any suggestions as to how AGN could improve on and/or extend its stakeholder engagement program?
4. Do you think this Draft Plan facilitates improved stakeholder engagement?
5. Is there any further information you would like on the pipeline services AGN is proposing?
6. Should AGN be changing the proposed pipeline services, if so what should we change?
7. Do you consider we have applied an appropriate approach to forecasting opex?
8. Should the non-base year costs outlined in this section be added to our opex forecast or absorbed by the business?
9. Do you support our proposal to expand our marketing program over the next AA period?
10. Do you consider that increases in opex attributable to the growth of our network are appropriately captured through growth in customer numbers (or should growth in throughput also be accounted for)? Should any output growth factor that is developed for gas distribution be subject to industry-wide consultation?
11. Do you consider we have applied an appropriate approach to forecasting capex?
12. Do you support the completion of our low pressure mains replacement program?
13. Do you support our risk assessment approach to delivering the volume of mains to be replaced, including our dedicated engagement with the ESV on this issue?
14. Have we appropriately considered and incorporated the outcomes of our stakeholder engagement program?
15. Do you agree that the value of low pressure mains should be removed from the capital base to reflect the completion of our low pressure mains replacement program? Do you agree with our proposal to depreciate these assets over five years, such that they are fully depreciated when the low pressure mains have been replaced?
16. Do you consider that the RBA-based approach will produce better forecasts of inflation relative to the market-based approach? Are there any other approaches to forecasting inflation that should be used/considered?
17. Do you have any other comments regarding our approach to adjust our capital base over the current and next AA periods?
18. Do you have any comments on our approach to setting the financing and tax costs in this Draft Plan?

Stakeholder Questions (continued)

19. Do you consider our approach to forecasting demand to be reasonable?
20. Are there other factors we should consider in developing our demand forecast? For example, are you aware of any potential future energy policy changes that will effect gas demand over the next AA period?
21. The Victorian government recently announced a target of zero carbon dioxide emissions by the year 2050. Do you think this announcement will impact gas demand over the next AA period, and if so, how should this be factored into our demand forecasts?
22. Do you support the objective of strengthening the incentives that apply to gas distributors? If so, should the incentive arrangements be consistent with that provided to electricity distributors?
23. What factors should be considered in informing a decision over the appropriate incentives to apply to gas distributors?
24. Do you agree that the EBSS should be retained?
25. Do you agree that a CESS should be re-introduced, including to provide a counterbalance to the EBSS?
26. Should the introduction of a CESS be accompanied by a counterbalancing STPIS? What types of measures should be included in a STPIS?
27. Do you support the introduction of a network innovation scheme aimed at better facilitating innovation or are the current arrangements sufficient? What level of allowance should be allowed under any proposed innovation scheme?
28. Do you think there is sufficient evidence to support increasing the incentive power of the EBSS and CESS?
29. Do you support our objectives of maintaining stable credit metrics and aligning revenue with underlying costs in setting our proposed price path? Would you prefer an alternate price path, and if so, on what basis?
30. Do you consider that explicit consideration should be given as to whether a pricing proposal provides sufficient cash flow to maintain the credit rating assumed by the AER in setting the cost of debt? If so, how do you think this assessment should be done – for example, by considering the credit metrics against levels assumed by ratings agencies? If an adjustment to prices is required, how should this be undertaken – for example, through changes in capitalisation or depreciation?
31. Do you consider that there is an appropriate split between our fixed and variable charges?
32. Do you agree with our proposed pricing structures, including our decision to align prices across the three Victorian zones of Central, Northern and Murray Valley and our decision not to consolidate price bands?
33. Is there anything that our Draft Plan hasn't considered that is important to you?
34. Is there any other feedback you would like to provide on our Draft Plan?

Abbreviations

Term	Meaning
AA	Access Arrangement
AAI	Access Arrangement Information
AA Proposal	AGN's submission to the AER, consisting of a revised AA proposal, AAI and other supporting documents
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGN	Australian Gas Networks Limited
AGN Qld	Australian Gas Networks Limited Queensland
AGN SA	Australian Gas Networks Limited South Australia
AGN Vic	Australian Gas Networks Limited Victoria
AIG	Australia Industry Group
APA	APA Asset Management/APA Group
ARS	Ancillary Reference Services
ASX	Australian Securities Exchange
AS 4645	Australian Standard 4645
ATO	Australian Tax Office
Capex	Capital expenditure
CBD	Central business district
CCP	Consumer Challenge Panel
CESS	Capital expenditure sharing scheme
CI	Cast iron
CTM	Custody transfer metering
current AA period	The current 1 January 2013 to 31 December 2017 Access Arrangement Period
DBYD	Dial Before You Dig
DMIS	Demand Management Incentive Scheme
DRP	Debt risk premium
EAM	Enterprise asset management
EBSS	Efficiency benefit sharing scheme

ECA	Energy Consumers Australia
ESV	Energy Safe Victoria
FFO	Funds from operations
GIS	Geospatial Information System
GJ	Gigajoule
GSL	Guaranteed Service Level
HDICS	High density inner city suburbs
HDPE	High density polyethylene
HIA	Housing Industry Association
HRS	Haulage Reference Services
IT	Information technology
KPIs	Key Performance Indicators
LDS	Low density suburbs
LTIFR	Lost time injury frequency rate
MHQ	Maximum hour quantity
MRP	Market risk premium
MTFP	Multilateral Total Factor Productivity
next AA period	The next 1 January 2018 to 31 December 2022 Access Arrangement Period
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
NSP	Network Service Providers
Ofgem	Office of Gas and Electricity Markets
OMA	Operating and Management Agreement
Opex	Operating expenditure
PMCs	Periodical meter changes
previous AA period	The previous 1 January 2008 to 31 December 2012
PVC	Polyvinyl chloride
RBA	Reserve Bank of Australia
RRG	Retailer Reference Group
SCADA	Supervisory Control and Data Acquisition

STPIS	Service Target Performance Incentive Scheme
TAB	Tax asset base
TFP	Total Factor Productivity
TJ	Terajoule
the networks	The Victorian and Albury natural gas distribution networks
the Vision	Australian Gas Networks Limited's Vision Statement
TSD	Thermal safety devices
UPS	Unprotected steel
VARG	Victoria/Albury Reference Group

Gas leaks and emergencies:

Gas leaks:
1800 427 532
(1800 GAS LEAK)

New connections and general enquiries:
1300 001 001

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(08) 8227 1500

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Have your say:
stakeholders.agnl.com.au/contact-us/

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