“High service levels, lower prices and increased investment”

Access Arrangement Information

For Australian Gas Networks’ South Australian Natural Gas Distribution Network

JULY 2015

Australian Gas Networks

Foreword from the CEO

I am delighted to present our plans for our South Australian gas distribution network (the Network) for the five-year period commencing 1 July 2016. We will deliver continuous improvement on our already high service levels, an 11% upfront cut in distribution prices (excluding inflation) and higher investment for the long-term health of the Network. Our plans have been informed by the stakeholder engagement program that we have undertaken.

Australian Gas Networks Limited (AGN) is one of Australia's largest natural gas distribution companies, serving around 1.2 million customers in South Australia, Victoria, Queensland, New South Wales and the Northern Territory.

AGN has delivered for South Australia over the 2011 to 2016 period. We will meet all key safety targets and have made improvements in network reliability. On average, our customers can expect an unplanned natural gas supply interruption of less than one hour every 40 years. We are on track to deliver 100% of our cast iron and steel mains replacement program. This important work has improved customer safety and reliability.

We intend, as a minimum, to maintain our strong safety and service levels over the next (2016 to 2021) period. We are proposing to complete the replacement of all cast iron and old steel gas mains in the Network by 2021 and to replace the oldest plastic mains on the Network. This program is the key driver for ensuring ongoing public safety and Network reliability.

We are very conscious that the cost of living, including utility bills, is a major concern for many people in South Australia. Distribution prices make up around half the average domestic retail gas bill, and so we have a role to play in the affordability challenge. I am therefore pleased that our proposal will deliver lower real (before inflation) distribution prices, on average, in the next period relative to current prices. We will deliver an 11% upfront price cut before inflation, with annual increases thereafter to match our growing asset base. Natural gas is a fuel of choice for our customers and I am pleased that it remains highly cost-effective as a domestic fuel compared to electricity.

Incentives on utility networks for good performance or penalties for poor performance are relatively weak in Australia. We are therefore proposing to strengthen the rewards for improvements in productivity and customer service over the next five years (and the penalties if performance worsens).

Our plans are based on the considerable experience of AGN and our primary contractor, APA Asset Management. They have been tested by qualified expert advisers and informed by our stakeholder engagement program. I would like to take this opportunity to thank the staff of AGN, APA Asset Management and the stakeholders that have informed our proposal.

Overall, we are proposing to continuously improve our strong safety, reliability and customer service levels, cut distribution prices on 1 July 2016 and increase investment. We are confident that our plan for 2016 to 2021 is in the long-term interests of South Australian customers.

Ben Wilson
Chief Executive Officer
Australian Gas Networks Limited

Page intentionally left blank

Table of Contents

List of Attachments

Page intentionally left blank

Abbreviations

Abbreviation	Description
AA	Access Arrangement
AAI	Access Arrangement Information
ABS	The Australian Bureau of Statistics
ACT	Australian Competition Tribunal
AEMA	Australian Energy Market Agreement
AEMC	The Australian Energy Market Commission
AEMO	The 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
AIC	Average Incremental Cost
AMP	Asset Management Plan
AMR	Automated Meter Reading
APA	APA Asset Management
ARORO	Allowed Rate of Return Objective
ARS	Ancillary Reference Services
ASX	Australian Securities Exchange
ATO	Australian Tax Office
AWOTE	Average Weekly Ordinary Time Earnings
BIS	BIS Shrapnel
CAC	Consumer Advisory Committee
CAM	Cost Allocation Model
CAPM	Capital Asset Pricing Model
Capex	Capital expenditure
CCP	Consumer Challenge Panel
CEO	Chief Executive Officer
CESS	Capital Expenditure Sharing Scheme
CGS	Commonwealth Government Securities
CI	Cast Iron
CMP	Capacity Management Plan
Core Energy	Core Energy Group
CPI	Consumer Price Index
CRC	Cooperative Research Centres
CSIRO	The Commonwealth Scientific and Industrial Research Organisation

current AA period	The current (2011/12 to 2015/16) Access Arrangement Period
DAE	Deloitte Access Economics
DCF	Discounted Cash Flow
DCVG	Direct Current Voltage Gradient
DD	Draft Decision
DGM	Dividend Growth Model
DP	Delivery Point
DRP	Debt Risk Premium
EAM	Enterprise Asset Management
EBSS	Efficiency Benefit Sharing Scheme
EDD	Effective Degree Day
EGWWS	Electricity, Gas, Water and Waste Services
ERAA	The Energy Retailers Association of Australia
ESCOSA	The Essential Services Commission of South Australia
ETC	Estimate of Corporate Income Tax
ETI	Estimate of Taxable Income
EWOSA	Energy and Water Ombudsman of South Australia
FEED	Front End Engineering and Design
FFM	Fama French Three Factor Model
FFO	Funds from Operations
GDB	Gas Distribution Business
GIS	Geospatial Information Systems
GSL	Guaranteed Service Level
GSP	Gross State Product
HDPE	High Density Polyethylene
HRS	Haulage Reference Services
HSS	Heat Shrink Sleeves
I & C	Industrial and Commercial
IRM	Innovation Roll-out Mechanism
IT	Information Technology
JGN	Jemena Gas Networks
KPI	Key Performance Indicator
LMP	Leakage Management Plan
LNG	Liquefied Natural Gas
LPI	Labour Price Index
LRMC	Long Run Marginal Cost
LTIFR	Lost-time Injury Frequency Rate
MAPS	Moomba to Adelaide Pipeline System
MDQ	Maximum Daily Quantity

MRP	Mains Replacement Plan
MTFP	Multilateral Total Factor Productivity
NECF	National Energy Customer Framework
NER	National Electricity Rules
next AA period	The next (2016/17 to 2020/21) Access Arrangement Period
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
NIA	Network Innovation Allowance
NIC	Network Innovation Competition
NIS	Network Innovation Scheme
NMF	Network Management Fee
NPV	Net Present Value
NSP	Network Service Provider
OMA	Operating and Management Agreement
Opex	Operating expenditure
ORG	Office of the Regulator General of Victoria
OTR	The South Australian Office of the Technical Regulator
PE	Polyethylene
PMC	Periodic Meter Change
PPI	Partial Productivity Indicator
PTRM	Post-tax Revenue Model
PV	Present Value
PwC	PricewaterhouseCoopers
RAB	Regulatory Asset Base
RAH	Royal Adelaide Hospital
RIIO	Revenue = Incentives + Innovation + Outputs
RIN	Regulatory Information Notice
RPP	Revenue and Pricing Principles
S&P	Standard & Poor's
SA	South Australia
SAIDI	System Average Interruption Duration Index
SAPN	SA Power Networks
SCADA	Supervisory Control and Data Acquisition
SEA Gas	South East Australia Gas Pipeline
SL CAPM	Sharpe-Lintner Capital Asset Pricing Model
TAB	Tax Asset Base
Tariff C	Commercial Customers

Tariff D	Demand Customers
Tariff R	Residential Customers
TFP	Total Factor Productivity
The Network	The South Australian natural gas distribution network
The Vision	Australian Gas Networks Limited's Vision Statement
TP	Transmission Pressure
UAFG	Unaccounted for Gas
UK	United Kingdom
UPS	Unprotected Steel
WA	Western Australia
WACC	Weighted Average Cost of Capital
WAPC	Weighted Average Price Cap
WPI	Wage Price Index
ZCM	Zero Consuming Meter

Executive Summary

Page intentionally left blank

Executive Summary

Australian Gas Networks Limited (AGN) is one of the largest natural gas distribution businesses in Australia. This Access Arrangement Information (AAI) has been prepared in respect of our South Australian natural gas distribution network (the Network). This AAI provides the necessary information to understand the proposed price and non-price terms of access to the Network over the next (2016/17 to 2020/21) Access Arrangement (AA) period. Over the next AA period, AGN will:

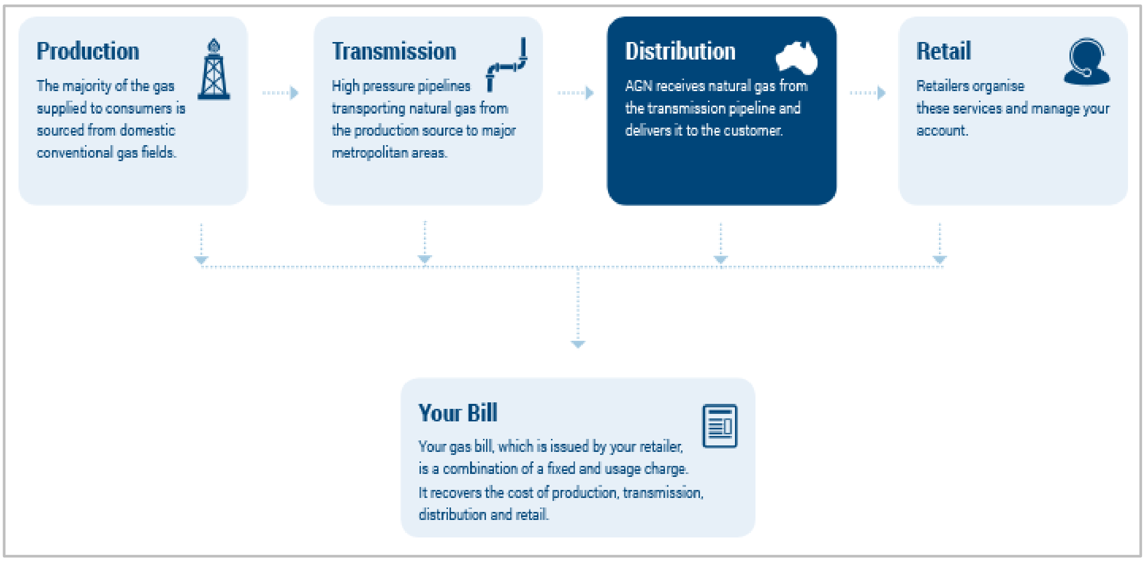
- deliver an upfront 11% reduction in distribution prices (or tariffs) in real (excluding inflation) terms, with prices lower on average in real terms over the next period compared to current prices;
- at least maintain our current high levels of reliability and customer service, which is consistent with the feedback received during our stakeholder engagement program;
- increase investment in our Network, including to complete the cast iron and unprotected steel mains replacement program and continue with the targeted replacement of our high-density polyethylene network; 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.

About Australian Gas Networks Limited

AGN owns the natural gas distribution network in South Australia. The origins of the Network date back over 150 years when the South Australian Gas Company was formed in 1861. The Network today provides natural gas distribution services in Adelaide, Mount Gambier, Whyalla, Port Pirie, the Barossa Valley, Murray Bridge and Berri.

As outlined in Figure 1, our distribution network receives natural gas from transmission pipelines and delivers that gas to the customer's home or business. Retailers are responsible for entering into contracts for the purchase of gas from the producer and for the transport of that gas on the transmission pipelines and the distribution network (owned by AGN). The distribution charge is a key part of the natural gas supply chain, accounting for around half of the bill issued by the retailer to the customer.

FIGURE 1: THE NATURAL SUPPLY CHAIN – GETTING GAS TO CUSTOMERS

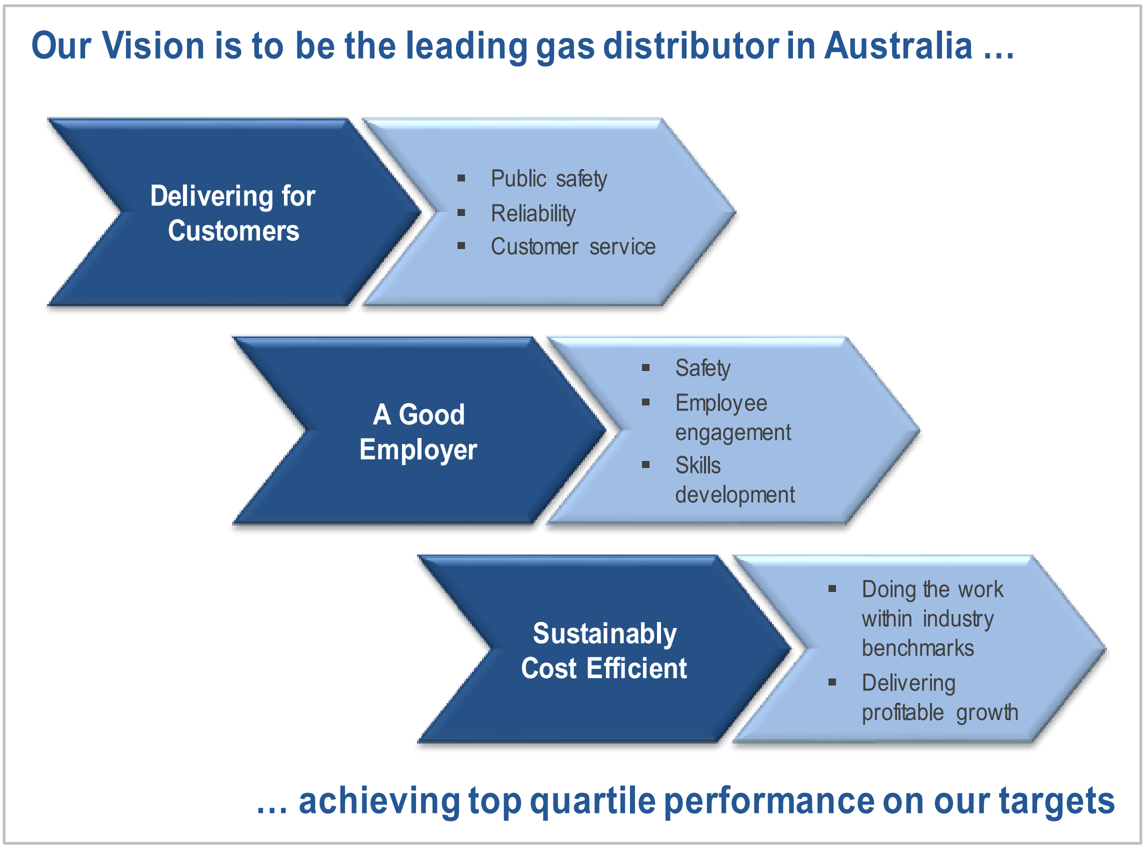


AGN aims to be the leading natural gas distributor in Australia (see Figure 2). Our definition of leading is to achieve top-quartile performance compared with other Australian natural gas distributors across all of our key targets. The AGN Vision Statement sets out the following three key objectives 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* – undertaking the required scope/volume of work within the benchmarks set by the Australian Energy Regulator (AER) while growing the network in a prudent and efficient manner.

Each year we set targets for all the key performance indicators outlined in our Vision Statement. We have committed to reporting to our stakeholders annually on our performance.

FIGURE 2: OUR VISION STATEMENT



Access Arrangement Proposal

Every five years, AGN is required to develop and submit to the AER for its approval our revised price and non-price terms of access to the Network. Our AAI, associated attachments and AA Document (together known as the AGN AA Proposal) have been developed having regard to the results of a dedicated stakeholder engagement program and the need to promote the National Gas Objective, which states:

> *"The objective of this [National Gas] Law is 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 of natural gas."*

Our AA Proposal has been subject to a rigorous verification process to ensure it is robust and in the long-term interests of consumers. More specifically, to develop our AA Proposal we have:

- drawn upon our considerable expertise and that of our contractor, APA Asset Management, to ensure that our proposed initiatives comply with all relevant regulatory requirements, including to ensure the safe and reliable supply of natural gas;
- sought independent expert advice wherever possible, including for the technical aspects of our proposal; and
- consulted with relevant industry stakeholders to inform the initiatives set out in this AA Proposal.

What We Will Deliver in 2011 to 2016

AGN will achieve the key safety targets set for the business and deliver the major outputs set by the AER for the current (2011/12 to 2015/16) AA period. More specifically, AGN will:

- comply with the safety requirements set out in our Leakage Management Procedure, which sets out the process for managing gas leaks on the Network;
- provide high levels of supply reliability to consumers, averaging only 15 interruptions affecting five or more customers per annum;
- connect more than 38,000 new customers to the Network, including extending the Network to Tanunda and the McLaren Vale (the McLaren Vale extension is due to be completed in 2015/16);
- achieve industry best practice employee safety levels, with only 1.3 lost time injuries per million hours worked;[1]
- deliver the full cast iron and unprotected steel mains replacement program approved by the AER for the current AA period (1,072 kilometres);
- commence the targeted replacement of our oldest high-density polyethylene network (100 kilometres) even though this is not funded by tariffs in the current AA period;
- through mains replacement, reduce the volume of gas losses on the Network by 34%, thereby improving cost efficiency and public safety; and
- design and implement a stakeholder engagement program to ensure our business plans are informed by stakeholder values.

What We Will Deliver in 2016 to 2021

Figure 3 sets out the key deliverables for the next AA period, which include that AGN will:

- deliver lower distribution tariffs, on average, in real terms compared to current (2015/16) tariffs;
- at least maintain our current high levels of public safety, customer service and network reliability;
- continue investment in the network, completing the cast iron and unprotected steel mains replacement program and continuing with the targeted replacement of our high-density polyethylene network;
- improve and strengthen the incentives for the business to incur prudent and efficient operating and capital expenditure and to make ongoing improvements in customer service; and

[1] The Lost-time Injury Frequency Rate (LTIFR) is the number of lost-time injuries (defined as an occurrence that resulted in a fatality, permanent disability or time lost from one day shift or more) over a year relative to the total number of hours worked.

- explore ways that we can improve the security of supply to our customers, including those located in regional areas.

Key elements of our AA Proposal are outlined in further detail below.

FIGURE 3: WHAT WE WILL DELIVER OVER THE NEXT ACCESS ARRANGEMENT PERIOD

	Which means….	2016/17 to 2020/21 Forecasts
Delivering for Customers	▪ Public safety ▪ Reliability ▪ Customer service	▪ High level performance to be maintained. ▪ Improve Network resilience. ▪ Circa 36,000 new connections. ▪ Plans informed by stakeholder engagement.
A Good Employer	▪ Safety ▪ Employee engagement ▪ Skills development	▪ Continuous improvement: - Lost-time Injury Frequency Rate (LTIFR): less than 1.0 per million hours.† - Restricted duties rate: less than 15 days. - Implementation of employee engagement program.
Sustainably Cost Efficient	▪ Doing the work within industry benchmarks ▪ Delivering profitable growth	▪ Lower distribution tariffs in real terms, with an initial 11% real cut. ▪ Complete cast iron and unprotected steel mains replacement (862 kilometres). ▪ Continued selective replacement of high-density polyethylene mains (411 kilometres). ▪ Improve and strengthen network incentives. ▪ Ongoing Network growth.

† LTIFR is the number of lost-time injuries (defined as an occurrence that resulted in a fatality, permanent disability or time lost from one day shift of more) over a year relative to the total number of hours worked (usually per million hours worked) in that year.

Stakeholder Engagement

AGN has developed and implemented a stakeholder engagement program to inform the initiatives set out in our AA Proposal. An important aspect was ensuring that our approach to engagement was robust and fit-for-purpose, having regard to our role in the natural gas supply chain and our impact on customers. The objective of our stakeholder engagement program was to ensure that our AA Proposal is reflective of stakeholder values and is consistent with promoting the requirements of the National Gas Objective.

Our approach to stakeholder engagement comprises four phases. The key features of each stage of our engagement program include:

- *Strategy Phase* – the development of our stakeholder engagement strategy for South Australia (which can be accessed at: http://stakeholders.agnl.com.au);

- *Research Phase* – holding community workshops and stakeholder interviews to capture and report on stakeholder insights;

- *Implementation Phase* – internal review of the implications of the stakeholder feedback on this AA Proposal for South Australia; and

- *Ongoing Engagement Phase* – a commitment by AGN to continually seek ways to improve our stakeholder engagement program and also to engage with our stakeholders on an ongoing basis.

During the Research Phase, stakeholders told us that they value our high reliability and want us to keep providing the same (as a minimum) service levels. They were interested in ways that we could improve the network, particularly with respect to network safety, and also wanted us to include them more by increasing transparency and our communication channels. They also raised concern about rising costs in general and wanted AGN to continually strive to achieve efficient pricing outcomes.

The stakeholder feedback was used to inform the business plans set out in this AA Proposal. Importantly, all initiatives proposed by AGN have a sound asset management and/or commercial foundation. Stakeholder engagement was used to inform our plans, such as the scope of a project and whether any proposed change in service levels is consistent with stakeholder values. Chapter 3 of this Access Arrangement Information describes our stakeholder engagement program in more detail.

AGN is confident that our AA Proposal reflects the feedback that we received during our stakeholder engagement program.

Incentives

AGN is a strong supporter of effective, outcome-based incentive arrangements as a way of improving the price and service outcomes provided to gas customers. Consistent with this, AGN is proposing that a more comprehensive set of incentive arrangements apply over the next AA period, including:

- the retention of the AER's operating expenditure incentive scheme (referred to as the efficiency benefit sharing scheme), albeit strengthened to provide an equal sharing of efficiency gains/losses between AGN and consumers;

- the introduction of the AER's capital expenditure (capex) incentive scheme, also modified to allow for an equal sharing of efficiency gains/losses in capex;

- the introduction of an incentive to promote lower cost and/or improved service delivery outcomes through innovation; and

- the development and introduction of a customer service incentive scheme during the next AA period.

AGN considers that these incentive arrangements will increase the scope for the business to make more cost-efficient investments, driving greater cost reductions while (at least) maintaining, if not improving, the quality, safety, reliability and security of supply of natural gas for customers, and therefore lead to outcomes that better promote the National Gas Objective.

Security of Supply

AGN is undertaking an extensive review of actions that it can take to improve the security of supply across the Network. This follows a major outage on the transmission pipeline (not owned by AGN) to Port Pirie on 12 April 2015, which resulted in the loss of natural gas supply to around 10,000 customers in Port Pirie and Whyalla for around one week (Whyalla receives supply from the same transmission line that supplies Port Pirie). The most recent outage in Port Pirie and Whyalla follows a similar outage that occurred around three years earlier in Whyalla.

It is reasonably common across the Network for large numbers of customers to receive natural gas from a single supply point, particularly in regional areas and in the outer suburbs of Adelaide. AGN is currently undertaking a detailed review to assess ways that the security of gas supply can be improved on the Network over the next AA period. AGN will discuss these proposals with relevant stakeholders, including the AER, once they have been further developed.

AGN has included a cost-pass-through mechanism in its South Australian AA Proposal that allows AGN to recover the costs of any security of supply initiative that meets the relevant criteria in the National Gas Rules for the approval of capex, as approved by the AER, during the next AA period.

Demand Forecasts

Forecasts of natural gas consumption and customer numbers (collectively referred to as demand forecasts) are a key input into determining expenditure related to new connections and, under a price cap form of regulation, the prices charged to retailers (and hence customers). AGN has only achieved the benchmark residential demand forecasts once in 16 years. AGN estimates that this has led to a $57 million shortfall in revenue over the current AA period.

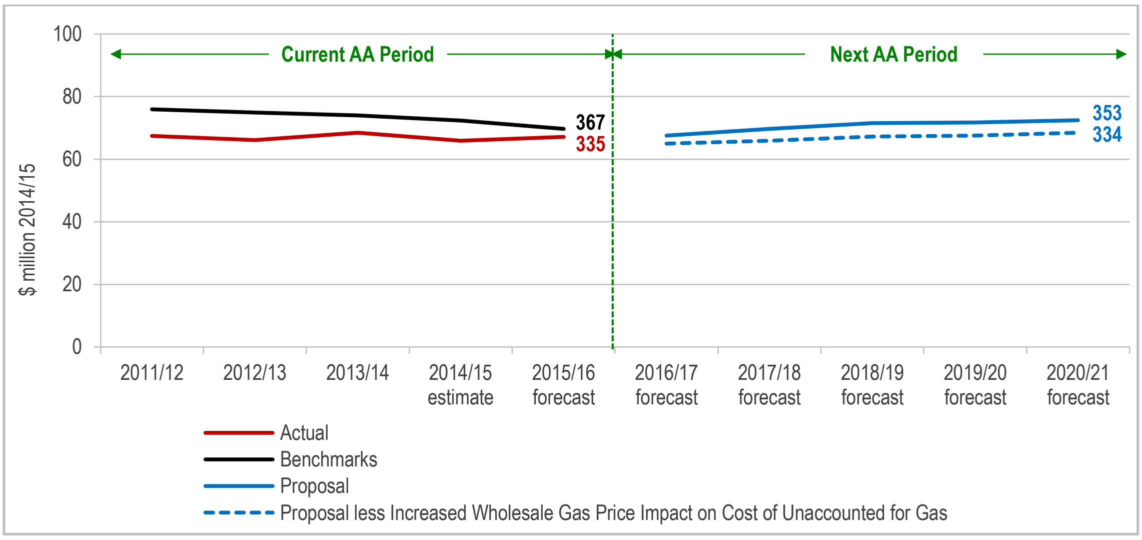
AGN is seeking to be provided with a reasonable opportunity to meet the forecast demand for the next AA period. The forecasts set out in our AA Proposal, which are based on advice from Core Energy Group, are largely based on past trends in gas connections and usage.

Expenditure

AGN is proposing to invest $353 million in operating expenditure (opex) and $699 million in capex over the next AA period, which is around 29% higher than the expenditure expected to be incurred over the current AA period (all values are expressed in current 2014/15 dollar terms unless stated otherwise).

In terms of opex, AGN incurred expenditure around 9% below that approved by the AER for the current AA period. This lower opex will be passed on to consumers over the next AA period. Our proposed opex, excluding the impact of rising wholesale gas prices on the cost of purchasing gas that is lost on the Network, is consistent ($334 million) with that incurred in the current AA period ($335 million), despite (for example) growing customer numbers and increased input costs.

FIGURE 4: CURRENT AND NEXT AA PERIOD OPEX



The main driver of our increased capital investment relates to the delivery of our mains replacement program. This AA proposal provides for 862 kilometres of cast iron and unprotected steel mains to be replaced over the next AA period, which would eliminate all cast iron and unprotected steel on the Network. This program is necessary to ensure the ongoing safe and reliable supply of natural gas to our South Australian customers, including by:

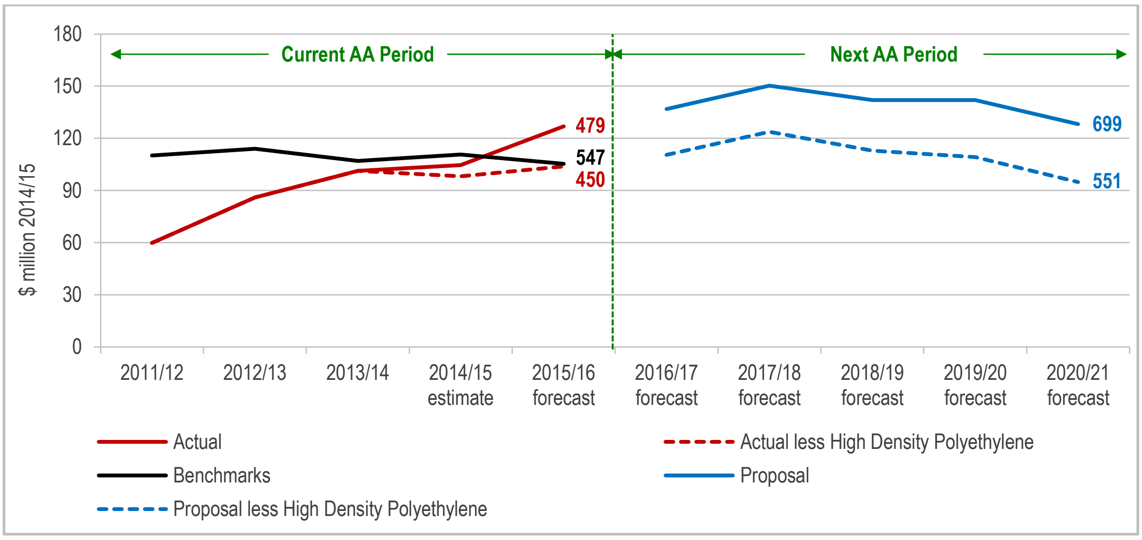
- reducing the risks to both public and employee safety associated with natural gas leakage from the Network;
- increasing network capacity by replacing low-pressure with high-pressure mains (which facilitates new customer connections and the ongoing shift towards instantaneous natural gas hot water appliances); and
- improving network reliability by reducing the incidence of unplanned outages from water ingress to pipes.

AGN has also commenced and will continue with the replacement of parts of the high-density polyethylene network over the next AA period. This is partly in response to failures that have occurred related to old high-density polyethylene mains. These mains date back to the 1970s.

Other key drivers of our proposed investment include:

- *growth capex* – which relates to the capex required to connect new consumers to the Network; and
- *Information Technology (IT)* – which allows for the continuation of the national program of work that was initiated in the current AA period to replace outdated and in many cases obsolete state-based IT systems with their enterprise equivalents servicing all five Australian jurisdictions in which AGN operates.

FIGURE 5: CURRENT AND NEXT AA PERIOD CAPEX



Note: Prior to 2013/14 "Actual less High Density Polyethylene" is equal to "Actual". This reflects that the program to replace the High Density Polyethylene mains commenced part way through the Current AA Period.

AGN is confident that the expenditure proposed for the next AA period is prudent, efficient and consistent with good industry practice to achieve the lowest sustainable cost of providing natural gas services to the consumers.

Financing Costs

AGN is seeking to receive a fair and reasonable rate of return on the investment it has made in the Network. This is essential in order for AGN to attract the necessary funding from our shareholders and debt providers to continue to invest in the Network over the next AA period. The rate of return on capital is our single largest cost, accounting for around half of the revenue recovered by the business.

AGN is proposing a significant reduction in the rate of return, from 10.28% (nominal, post-tax) applying in the current AA period, to 7.23% proposed for the next AA period. This reduction reflects the easing of financial markets following the global financial crisis. The proposed rate of return has been arrived at having regard to all available and relevant data, estimation methods, financial models and evidence. AGN has also relied upon the advice of independent experts.

In formulating its rate of return, AGN has carefully considered the AER's Rate of Return Guidelines and recent determinations for New South Wales, the Australian Capital Territory and Tasmania. However, in order to ensure that AGN can continue to attract the required funds from debt and equity investors and to comply with the National Gas Rules and National Gas Law, AGN's proposed rate of return departs from the Guideline and recent AER decisions in respect of both the return on equity and return on debt.

The key difference between the AER and AGN on the return on equity relates to the financial models that are used to inform the estimate. AGN considers that recent changes to the framework set out in the National Gas Rules for estimating the return on equity intended to broaden the inputs used to set this parameter. Despite this, the AER has continued to place primary reliance on one particular model to estimate the return on equity whereas AGN places reliance on several models.

A multi-model approach reduces the 'lottery effect' of setting a rate of return for five years based on where interest rates happen to be in a 20-day period just prior to the commencement of the AA period. A multi-model approach also produces estimates for the cost of equity that are more stable over time than an approach that relies on a single model.

In terms of debt, both the AER and AGN agree that a change in the approach to estimating the return on debt is appropriate. This approach seeks to estimate a 10-year trailing average of the return on debt incurred by a benchmark efficient business. The key area of difference is how to transition to this new approach from the previous 'on-the-day' approach, which estimated the cost of debt based on a short-term averaging period. While there are a number of options, the most common are:

- *the AER transition approach* – which implements a 10-year transition to implementing the 10-year trailing average approach;
- *no transition approach* – which implements a 10-year trailing average approach at the start of the regulatory period; and
- *a hybrid transition approach* – which implements the 10-year transition to the base interest rate component but not to the debt risk premium component of the cost of debt.

AGN is proposing the hybrid transition approach on the basis that this is most consistent with the debt financing practices of a benchmark efficient business facing the risks of AGN. Indeed, better replicating the financing practices of a benchmark efficient business was the key driver in moving to a 10-year trailing average cost of debt. Consistent with this, no transition is required for the debt risk premium given businesses such as AGN currently incur these costs now (reflecting that it is not possible to 'hedge' the debt risk premium and that it already reflects a trailing average).

Our proposed 7.23% rate of return comprises a return on equity of 9.91% and a return on debt of 5.44%. This estimate differs materially from the AER's rate of return recently set for SA Power Networks (5.45%, based on a return on equity of 7.10% and a return on debt of 4.35%).

Distribution Prices

Despite our growing investment and proposal to maintain service and reliability levels, AGN is proposing that the total revenue to be recovered from the Network over the next AA period decreases by 9% (to $1,050 million) relative to the benchmark set for the current AA period. This reduction in revenue is primarily driven by the above-mentioned fall in the rate return.

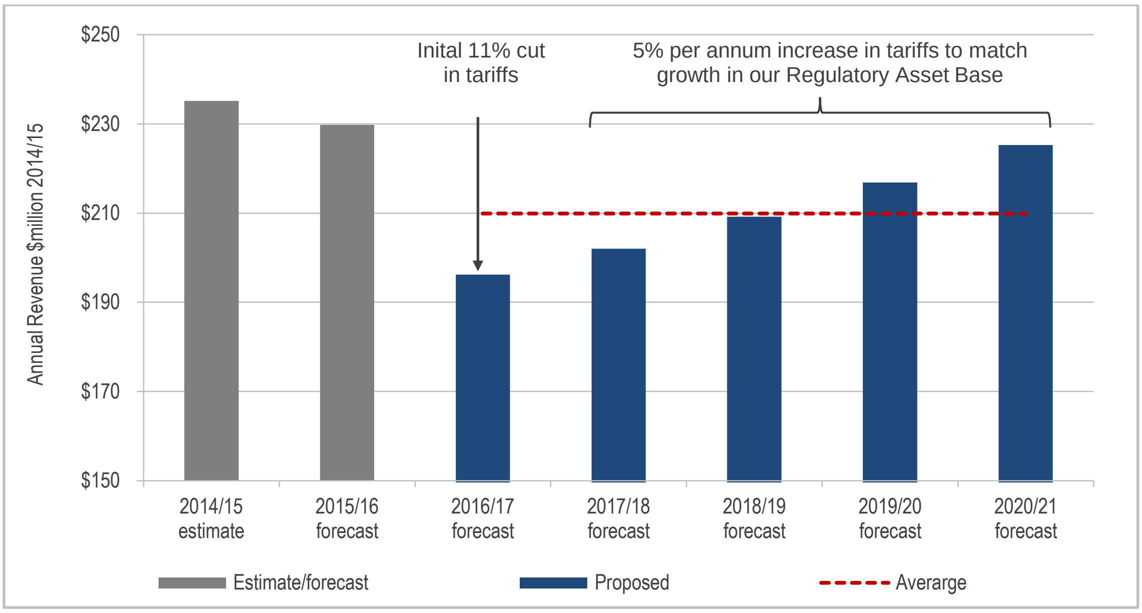
This revenue is recovered from the distribution prices (or tariffs) charged to retailers for transporting gas on the Network. AGN has developed its proposed price path in order to:

- provide for revenue growth that, to the extent possible, matches the growth in the regulatory asset base over the next AA period, which we consider is both sustainable and consistent with maintaining stable credit metrics (i.e. the AER benchmark credit rating of BBB+/Baa1); and

- to equate revenue with our underlying costs in 2020/21 (the last year of the next AA period) to ensure that there is no one-off adjustment to tariffs (either positive or negative) required from 1 July 2021 to equate tariff revenue with underlying costs.

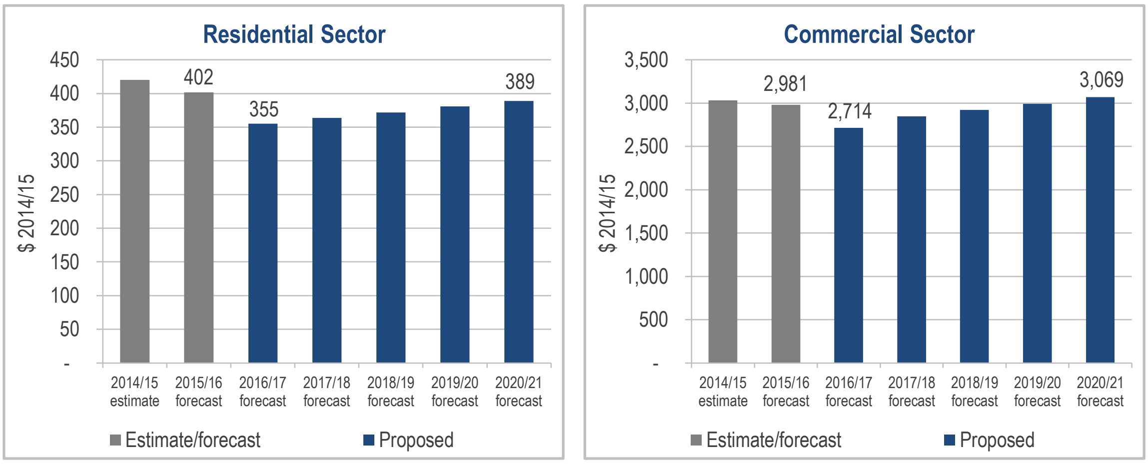
This approach leads to an upfront price cut on 1 July 2016, followed by price growth (in line with the growth in our regulatory asset base). More specifically, AGN is proposing to reduce distribution tariffs by 11% in real (excluding inflation) terms on 1 July 2016, followed by tariff increases of 5% in real terms in each remaining year of the next AA period (see Figure 6).

FIGURE 6: CURRENT AND NEXT AA PERIOD REVENUE



The resultant impact on the distribution component of the natural gas retail bill for the average residential and commercial customer over the next AA period are shown in Figure 7. The average residential customer will receive, in each year of the next AA period, a real (excluding inflation) reduction in their distribution charge relative to what they pay today. Commercial customers will also receive a reduction to their annual distribution charge at the beginning of the period, before climbing to be marginally higher than their current charge.

FIGURE 7: IMPACT ON THE AVERAGE DISTRIBUTION CHARGE (REVENUE PER CUSTOMER)



Next Steps

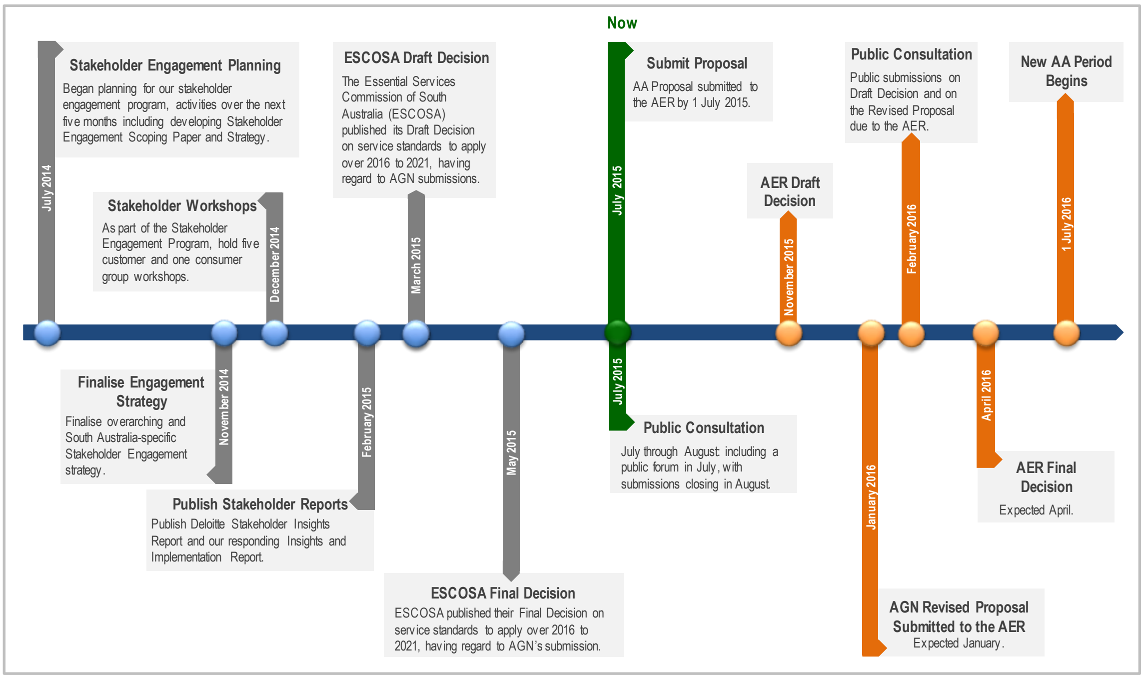
This AA Proposal has been submitted to the AER for its consideration. Stakeholders will have the opportunity to engage with both AGN and the AER leading into the release of the AER's Final Decision, which is expected to be made available to the public in April 2016.

The key dates for the review of our AA Proposal are set out in Figure 8 and include:

- *July 2015* – AGN to submit its AA Proposal to the AER;
- *November 2015* – AER to release its Draft Decision on our AA Proposal;
- *January 2016* – AGN to respond to the AER Draft Decision;
- *February 2016* – Stakeholder feedback to the AER Draft Decision and AGN responding submission; and
- *April 2016* – AER to release its Final Decision.

AGN is seeking to engage with stakeholder groups on an ongoing basis. Feedback from our stakeholders can also be provided at any point in the future via our dedicated stakeholder website (www.stakeholders.agnl.com.au).

FIGURE 8: HISTORIC AND FUTURE KEY MILESTONES



Part A
Background

Page intentionally left blank

1 Introduction

Australian Gas Networks

Page intentionally left blank

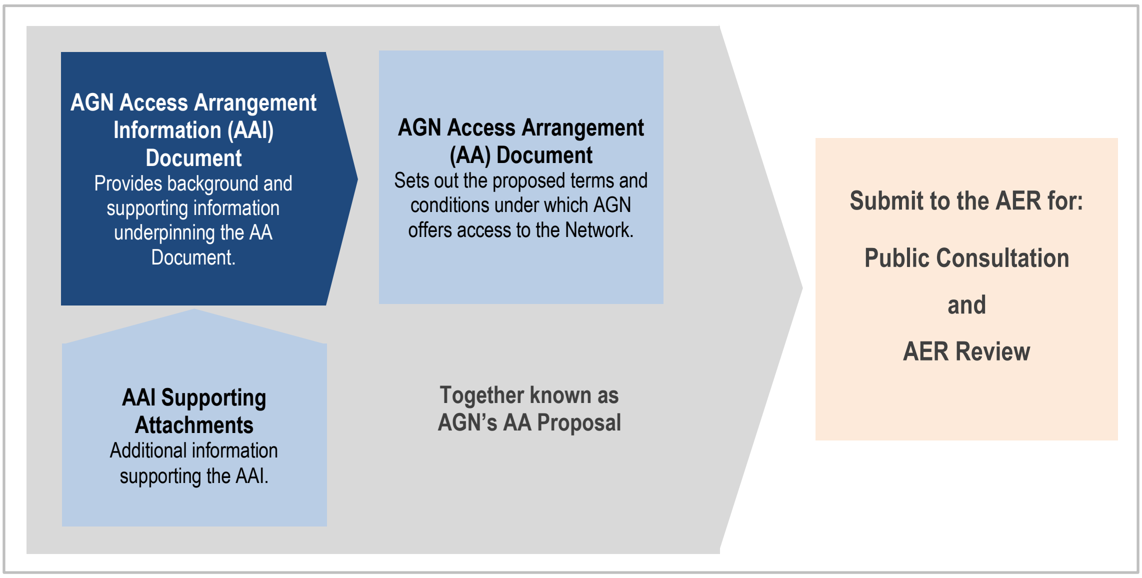
1 Introduction

1.1 Purpose of this Document

This Access Arrangement Information (AAI) has been prepared by Australian Gas Networks Limited (AGN). The purpose of the AAI is to provide the necessary information to understand the proposed revisions to the Access Arrangement (AA) that applies in respect of the South Australian natural gas distribution network (the Network) owned by AGN. The AA sets out the price and non-price terms and conditions governing access to the Network.

The revised AA is to apply for the five-year period commencing 1 July 2016 (referred to in the AAI as the next AA period). This AAI, the supporting attachments to the AAI and the revised AA itself are collectively referred to as the AA Proposal. Pursuant to the relevant regulatory framework, AGN is required to submit the AA Proposal to the Australian Energy Regulator (AER) by 1 July 2015 for its review (see Figure 1.1).

FIGURE 1.1: THE ACCESS ARRANGEMENT PROPOSAL



In addition to the documents outlined in Figure 1.1, AGN has developed and published a customer overview document that provides a short summary of the key issues driving our AA Proposal.

This chapter describes the Network and the relevant regulatory framework governing the development and approval of the AA Proposal. This chapter also discusses the process followed by AGN to prepare the AA Proposal, the structure of the AAI and the further opportunities for stakeholders to provide input into the development of the AA.

1.2 The South Australian Network

The Network comprises 7,950 kilometres of distribution and transmission mains. The majority of the Network is located in the Adelaide metropolitan area, followed by the larger regional centres of Mount Gambier, Port Pirie, Whyalla and Peterborough. The Network also supplies certain parts of the Barossa Valley and the Riverland (see Chapter 2 for further information on the Network).

1.3 Relevant Regulatory Framework

This section explains the relevant regulatory framework governing the AA review process, with a focus on the overarching requirements that must be satisfied for the revised AA to be approved by the AER.

1.3.1 Overarching Regulatory Framework

The overarching regulatory framework is set out in the *National Gas (South Australia) Act 2008* (the Act). Section 7 of the Act applies the National Gas Law (NGL), which is set out in a Schedule to the Act, as a law of South Australia. The NGL, among other things, establishes the National Gas Objective (NGO) and the functions and powers of key administrative bodies. Importantly:

- Section 26 of the NGL gives the National Gas Rules (NGR) the force of law in South Australia. The NGR establish the process for the review of an AA and sets out the detailed requirements of an AA revision proposal; and

- Section 27 of the NGL makes the AER responsible for making a decision in relation to an AA revision proposal submitted by AGN.

Rule 52 of the NGR requires that AGN submit by 1 July 2015 (the 'review submission date') an AA revision proposal for the next (2016/17 to 2020/21) AA period. Rule 43 requires AGN, when submitting an AA revision proposal, to submit an AAI for the AA. Rule 42 states that an AAI is to contain information that is reasonably necessary for users and prospective users to:

- understand the background to the AA revision proposal; and

- understand the basis and derivation of the various elements of the AA revision proposal.

An AA sets out the terms and conditions under which AGN provides access to users of the Network.

1.3.2 National Gas Objective

Section 27 of the NGL prescribes the functions and powers of the AER, which includes economic regulatory functions and powers. Section 28 of the NGL provides that the AER must, in performing or exercising an economic regulatory function or power, perform or exercise that function or power in a manner that will or is likely to contribute to the achievement of the NGO, which is set out in Section 23 of the NGL. The NGO is:

> *"… 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 of natural gas."*

Further, pursuant to Section 28(1)(b)(iii), where there are two or more possible decisions open to the AER that will contribute to the achievement of the NGO, the AER must make the decision that the AER is satisfied will or is likely to contribute to the achievement of the NGO to the greatest degree.

1.3.3 Revenue and Pricing Principles

Section 28 of the NGL provides that the AER must also take into account the revenue and pricing principles when exercising a discretion in approving or making those parts of an AA relating to reference tariffs. Section 24 of the NGL sets out the revenue and pricing principles, which include the following:

- under Sub-section 24(2), a service provider should be provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs in providing reference services and complying with a regulatory obligation or requirement or making a regulatory payment;

- under Sub-section 24(3), a service provider should be provided with effective incentives in order to promote economic efficiency with respect to reference services the service provider provides, including:

    - efficient investment in, or in connection with, a pipeline with which the service provider provides reference services;

  - the efficient provision of pipeline services; and
  - the efficient use of the pipeline;

- under Sub-section 24(5), a reference tariff should allow for a return commensurate with the regulatory and commercial risks involved in providing the reference service to which that tariff relates;

- under Sub-section 24(6), regard should be had to the economic costs and risks of the potential for under and over investment by a service provider in a pipeline with which the service provider provides pipeline services; and

- under Sub-section 24(7), regard should be had to the economic costs and risks of the potential for under and over utilisation of a pipeline with which a service provider provides pipeline services.

1.3.4 Interrelationships

Pursuant to Section 28(1)(b)(ii) of the NGL, the AER in making its decision must specify the manner in which the constituent components of the decision relate to each other and the manner in which that interrelationship has been taken into account in making the decision.

1.3.5 AER Discretionary Powers

The exercise of the AER's discretion in its decision-making process regarding an AA revision proposal, including in deciding whether AGN has satisfied the NGO and the revenue and pricing principles, is governed by Rule 40 of the NGR, which provides that:

- under Sub-rule 40(1), if the NGL states that the AER has no discretion under a particular provision of the NGL, then the AER's discretion is entirely excluded in regard to an element of an AA revision proposal that is governed by the relevant provision;

- under Sub-rule 40(2), if the NGL states that the AER's discretion under a particular provision of the NGL is limited, then the AER may not withhold its approval to an element of an AA revision proposal that is governed by the relevant provision if the AER is satisfied that it:
  - complies with the applicable requirements of the NGL;
  - is consistent with applicable criteria (if any) prescribed by the NGL; and

- under Sub-rule 40(3), in all other cases the AER has full discretion to withhold its approval to an element of an AA revision proposal if, in the AER's opinion, a preferable alternative exists that:
  - complies with the applicable requirements of the NGL; and
  - is consistent with applicable criteria (if any) prescribed by the NGL.

1.3.6 Requirements of an Access Arrangement Information

Rule 72 of the NGR states that an AAI in respect of an AA revision proposal must include:

- capital expenditure (by asset class), operating expenditure (by category) and usage of the pipeline, over the previous AA period;

- the derivation of the change in the capital base over the previous AA period;

- the projected capital base over the AA period, including forecasts of conforming capital expenditure and depreciation and the bases for the forecasts;

- to the extent it is practicable, a forecast of pipeline capacity and utilisation of pipeline capacity over the AA period and the basis for the forecast;
- a forecast of operating expenditure over the AA period and the basis for the forecast;
- the key performance indicators to be used to support expenditure to be incurred over the AA period;
- the proposed rate-of-return on equity and debt, including any departure from the methodologies set out in the rate of return guidelines and the reasons for that departure;
- the estimated cost of corporate income tax, including the proposed value of imputation credits;
- a demonstration of how an allowance is to be made for any increments or decrements or efficiency gains or losses made under any incentive mechanism that applied in the previous AA period;
- the proposed approach to the setting of reference tariffs, including the method used to allocate costs and a demonstration of the relationship between costs and tariffs;
- the rationale for any proposed reference tariff variation mechanism;
- the rationale for any proposed incentive mechanism; and
- the total revenue to be derived from pipeline services for each regulatory year of the AA period.

Furthermore, Rule 74 of the NGR requires that a forecast or estimate used in an AA proposal must:

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

1.4 Compliance of the Revised Access Arrangement Proposal

On 18 May 2015 the AER issued a Regulatory Information Notice (RIN) to AGN. The RIN prescribes the detailed information required by the AER to assess our AA Proposal, including the information requirements set out in Rule 72 (and explained in Section 1.3.6). The completed RIN is provided at Attachment 1.1 to the AAI, while Attachment 1.2 explains where the information required by the RIN can be found in the AA Proposal.

Importantly, the forecasts and estimates used in the AA Proposal have been subject to a rigorous verification process, the key features of which are summarised below:

- forecasts are based on the considerable expertise of AGN and its contractor, APA Asset Management;
- forecasts for projects have been based on robust business plans that have been subject to thorough review as to their compliance with the relevant requirements of the NGL and NGR;
- where possible, forecasts have been based on the most recent actual information available, which information reflects revealed efficient expenditure/outcomes;
- all relevant drivers of a particular forecast have been taken into account and explained in this AAI, including by providing any data used to derive a particular forecast;
- reliance has been made on independent expert advice in the preparation of forecasts and estimates, which advice has been attached to this AAI;
- input was received from the South Australian Office of the Technical Regulator on our mains replacement program, which forms a key element of our AA Proposal; and

- (related to the above) relevant industry stakeholders have been consulted, where appropriate, in deriving a forecast, plan and/or estimate.

With regard to the last point, this AA Proposal is the first time that AGN has developed and implemented a dedicated stakeholder engagement program to inform the initiatives described in this AAI. AGN is confident that our AA Proposal reflects the feedback that we received during our stakeholder engagement program. More detailed information on our engagement program is provided in Chapter 3 of this AAI.

In addition to the above, AGN has provided a Statutory Declaration from its Chief Executive Officer, Mr Ben Wilson, verifying that:

- actual information provided in the RIN has been prepared in accordance with the requirements of the RIN and is true and accurate; and

- forecast information provided in the RIN is a best estimate that has been prepared in accordance with the RIN and the basis for that forecast has been provided in the AA Proposal.

The signed Statutory Declaration is provided as Attachment 1.3. The actual and forecast information, including the basis for any forecast, can be accessed in the RIN Index (Attachment 1.2). AGN has also included in this proposal the detailed models that have been used to determine the value of our regulatory asset base (Attachment 1.4) and the derivation of the total revenue required over the next AA period (Attachment 1.5).

Finally, AGN has sought the opinion of Dr Greg Houston of HoustonKemp Economists on whether our AA Proposal (insofar as it relates to the rate of return and the value of imputation credits, or gamma), is materially preferable in making a contribution to the NGO having regard to previous decisions made by the AER, including in its Rate of Return Guideline. The Houston Report is provided as Attachment 1.6 to this AAI.

Dr Houston has focused on recent decisions of the AER on the allowed rate of return and gamma, as the AER has not as yet made a decision in respect of other aspects of this AA Proposal. The key conclusion of Dr Houston is as follows:

> *"In my opinion, a decision that corrects the errors identified in each of the expert reports – either separately or in combination – would result in a materially preferable designated NGO decision, because it is more likely to promote the long term interests of consumers to a materially greater degree without compromising the short term interests of consumers, as compared with the decision made by the AER in its Guideline and recent decisions."*[2]

AGN is confident that this AA Proposal, including this AAI, provides all the necessary information and complies with all relevant requirements of the NGL and NGR.

1.5 Structure of this Document

This AAI is structured as follows:

- *Part A: Background* – Provides background information on the relevant regulatory framework, a business overview of AGN's operations, services and key business drivers, explains our stakeholder engagement program and our performance over the current (2011/12 to 2015/16) AA period;

- *Part B: Our Proposal* – A summary of what we plan to deliver over the next (2016/17 to 2020/21) AA period;

---

[2] Houston Kemp 2015, "*Australian Gas Networks - AER Gas Price Review*", June 2015, pg.45. Provided as Attachment 1.6 to this AAI.

- *Part C: Derivation of Total Revenue* – Covers the key components (or building blocks) that are used to derive total revenue for each year of the next AA period, including the return on capital, depreciation, operating expenditure, taxation and the outcomes of the incentive mechanism that applied in the current AA period;

- *Part D: Derivation of Reference Tariffs* – Covers factors relevant to the derivation of reference tariffs, including the demand forecasts used to derive reference tariffs and an explanation of how those reference tariffs can change over the next AA period; and

- *Part E: Other* – Describes the non-tariff components of the AA proposal.

Table 1.1 provides further detail on the chapters within each Part of the AAI.

TABLE 1.1: STRUCTURE OF THE ACCESS ARRANGEMENT INFORMATION DOCUMENT

Chapter	Overview
Part A – Background	
1. Introduction	Purpose, requirements and structure of AGN's submission to the AER.
2. Business Overview	A description of our business, including, the physical network, our customers, services, company vision and performance.
3. Stakeholder Engagement	An overview of our stakeholder engagement program, including the development and implementation of the program.
4. Past Performance	A description of our performance against key metrics over the current AA period.
Part B – Our Proposal	
5. What we will Deliver	A summary of the key outputs/outcomes that we propose to deliver over the next AA period.
Part C – Derivation of Total Revenue	
6. Pipeline Services	A description of the services AGN will provide over the next AA period.
7. Operating Expenditure	A forecast of operating expenditure over the next AA period.
8. Capital Expenditure	A forecast of capital expenditure over the next AA period.
9. Regulatory Asset Base	The derivation of the opening and closing regulatory asset base over the next AA period.
10. Rate of Return	The derivation and component analysis of the rate of return to apply over the next AA period.
11. Cost of Tax	The derivation of the opening and closing tax asset base, a forecast of corporate income tax and the associated value of imputation credits over the next AA period.
12. Incentive Arrangements	Performance under the incentive arrangements that applied over the current AA period and the proposed incentive arrangements to apply over the next AA period.
13. Total Revenue	The derivation of total revenue and the associated price path over the next AA period.
Part D – Derivation of Reference Tariffs	
14. Demand Forecasts	Forecasts of customer numbers and natural gas volumes over the next AA period.
15. Reference Tariffs	A description of the reference tariffs and their application over the next AA period.
16. Tariff Variation Mechanisms	A description of the approach and formulae for varying reference tariffs.
Part E – Other	
17. Non-Tariff Components	A description of the non-price terms and conditions to apply over the next AA period.

The structure of our AA Proposal is summarised in the Document Map provided at Attachment 1.7 to this AAI. The Document Map illustrates the relationship of all Attachments to the AAI to the above chapters outlined in Table 1.1.

At times, this document relies upon commercial or customer-sensitive information. To protect intellectual property and customer information, confidential information has been redacted from the public version of this AAI and some attachments are not made available to the public. Any such confidentiality claims have been made in a manner that is consistent with the AER's *Better Regulation Confidentiality Guideline*.[3]

Importantly, confidential information has been provided to the AER for its review against the relevant requirements of the NGL and NGR. Attachment 1.8 provides a summary of the confidentiality claims made by AGN with respect to the information provided in this AA Proposal.

1.6 Determination Timeframes and Feedback Opportunities

As already noted, AGN has engaged with key stakeholders in developing this AA Proposal. The feedback so far received from stakeholders has been reported throughout this AAI. AGN intends to engage with stakeholder groups on an ongoing basis, including during the AER review process. The AER will also seek stakeholder feedback during its own review process, including in response to an AER Issues Paper and Draft Decision on our AA Proposal.

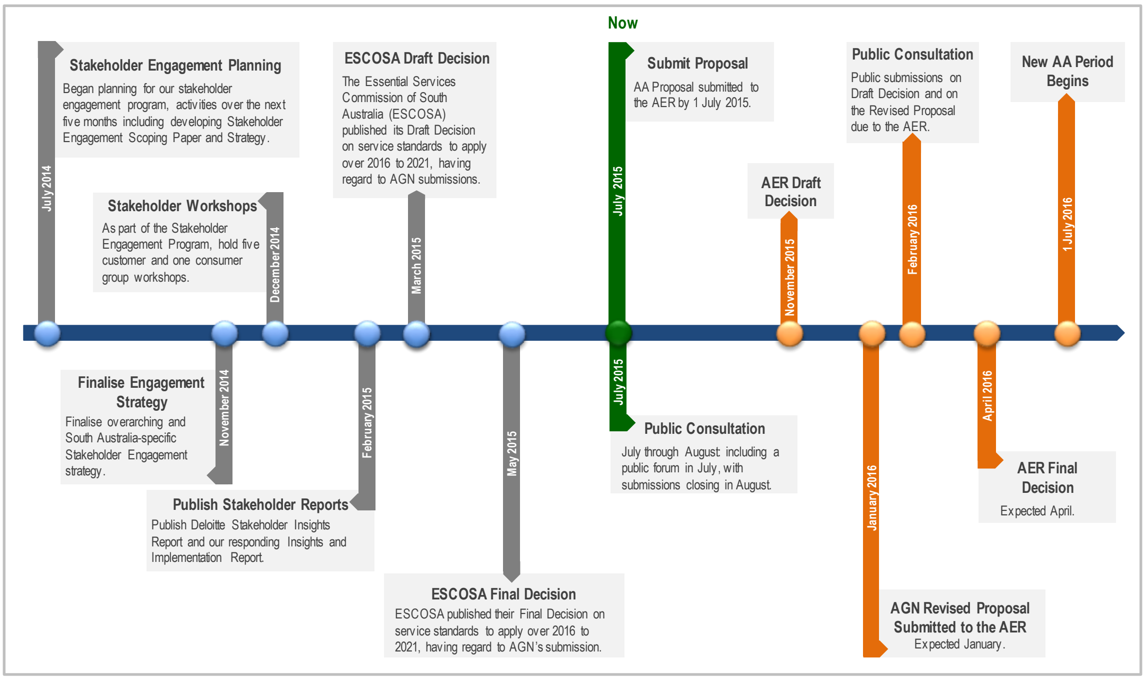
The key dates for the review of our AA Proposal are set out in Figure 1.1 and include:

- *July 2015* – AGN to submit its AA Proposal to the AER;
- *November 2015* – AER to release its Draft Decision on our AA Proposal;
- *January 2016* – AGN to respond to the AER Draft Decision;
- *February 2016* – Stakeholder feedback to the AER Draft Decision and AGN responding submission; and
- *April 2016* – AER to release its Final Decision.

AGN is also seeking feedback from our stakeholders at any point in the future via our dedicated stakeholder website (www.stakeholders.agnl.com.au).

[3] AER 2013, "*Better Regulation Confidentiality Guideline*", November 2013.

FIGURE 1.2: HISTORIC AND FUTURE KEY MILESTONES



1.7 Interpretation

Terms used in this AAI have the same meaning as they have in the AA Document. More specifically, in this AAI:

- a reference to a year such as 2015, is a reference to the financial year 2014/15;
- monetary values are generally expressed real 2014/15 dollar terms, unless indicated otherwise;
- certain numerical values may not precisely equate due to rounding;
- a reference to gas is a reference to natural gas unless otherwise specified;
- a reference to opex is a reference to operating expenditure and a reference to capex is a reference to capital expenditure (a full list of abbreviations is provided earlier in this AAI); and
- a reference to a 'Rule' is a reference to a National Gas Rule.

In this AAI, unless the context otherwise requires, where a word or meaning is capitalised it has:

- the meaning given to that word or phrase in the National Gas Rules; or
- the meaning given to that word or phrase in the glossary contained in the Access Arrangement.

1.8 Contact Details

The contact person for further details in relation to this AAI and the AA Proposal to which it relates is:

Craig de Laine

General Manager – Regulation

Australian Gas Networks Limited

Level 6, 400 King William Street

Adelaide SA 5000

Phone: (08) 8227 1500

Page intentionally left blank

2 Business Overview and Track Record

Australian Gas Networks

Page intentionally left blank

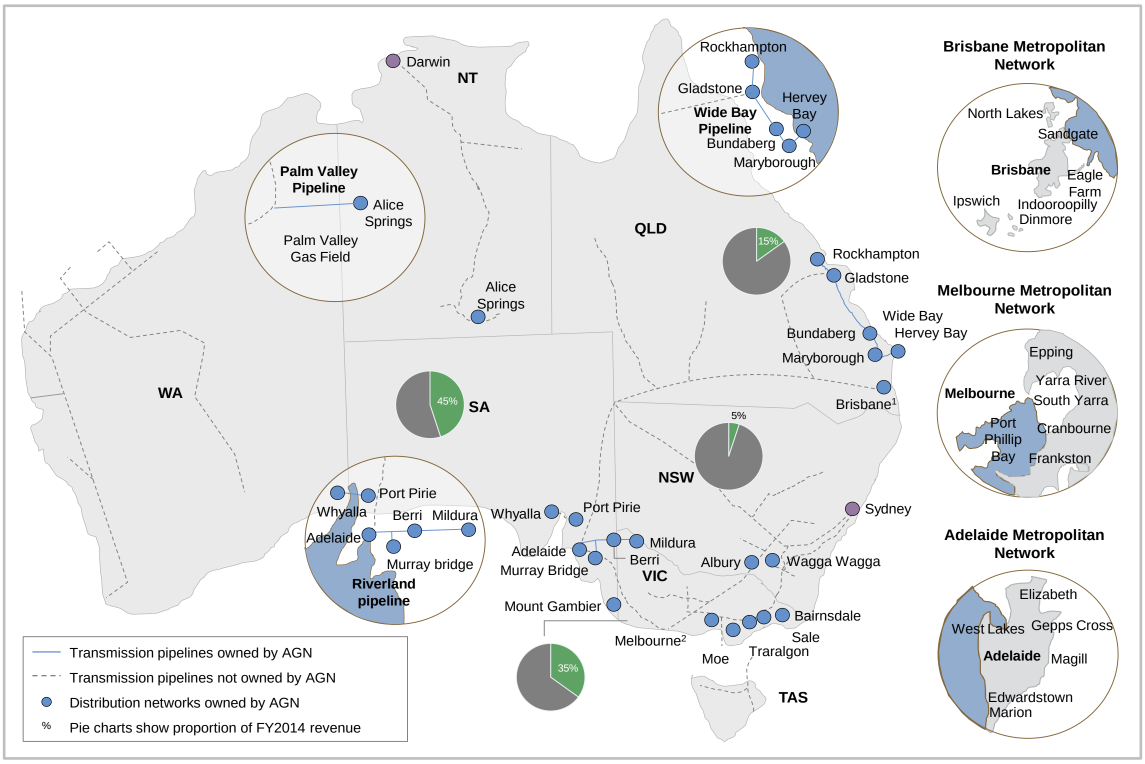
2 Business Overview and Track Record

2.1 Introduction

Australian Gas Networks Limited (AGN) is one of the leading natural gas distribution businesses in Australia, servicing 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 South Australia, Victoria, Queensland, New South Wales and the Northern Territory (see Figure 2.1). AGN is owned by the Cheung Kong Hutchinson Group of companies based in Hong Kong.

This chapter provides an overview of our covered South Australian natural gas distribution network (the Network), including network location and size. This chapter also sets out our vision and summarises our performance against this vision over the current (2011/12 to 2015/16) Access Arrangement (AA) period.

FIGURE 2.1: MAP OF AGN'S NETWORKS

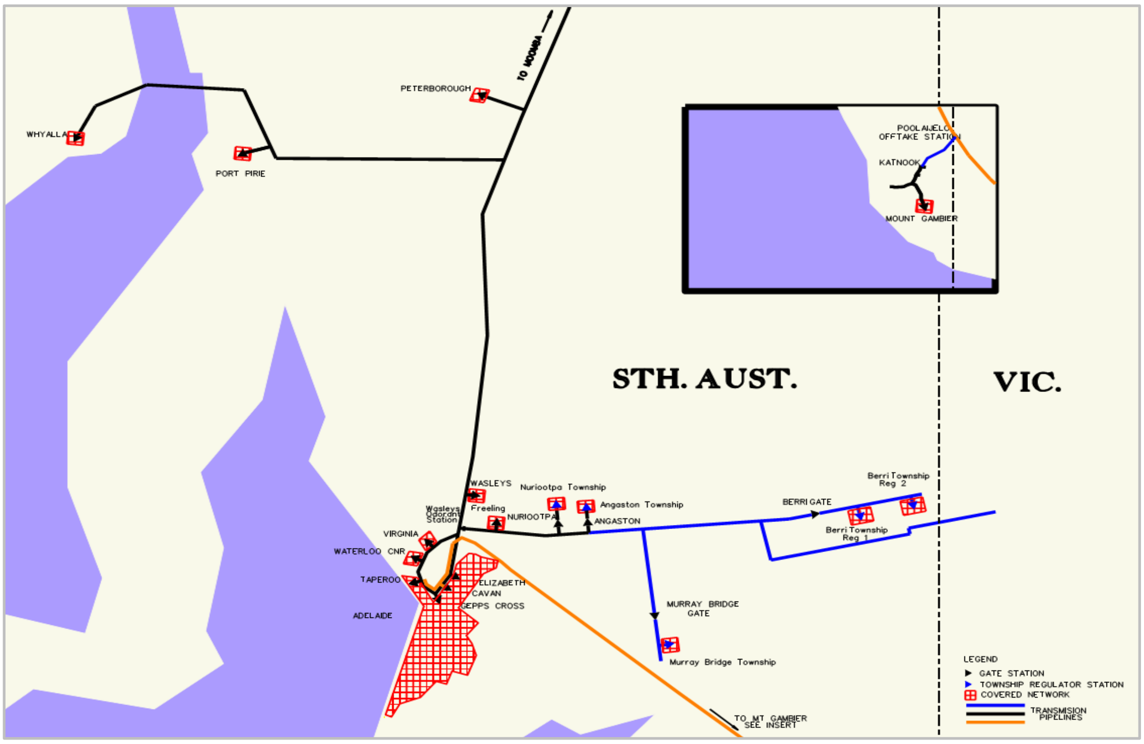


2.2 Description of the Network

2.2.1 Network Configuration

The Network has its origins dating back over 150 years when the South Australian Gas Company was formed in 1861. The Network today provides gas distribution services in Adelaide, Mount Gambier, Whyalla, Port Pirie, the Barossa Valley, Murray Bridge and Berri. Figure 2.2 provides an overview of the areas served by the Network.

FIGURE 2.2: MAP OF THE SOUTH AUSTRALIAN NATURAL GAS DISTRIBUTION NETWORK



The Network receives natural gas from the following two gas transmission pipelines:

- Moomba to Adelaide Pipeline System (MAPS) – which transports natural gas primarily from the Cooper Basin; and
- South East Australia Gas Pipeline (SEAGas) – which transports natural gas from the Otway and Bass Basins.

Network Users, who are primarily natural gas retailers, are responsible for injecting natural gas from a transmission pipeline (i.e. MAPS or SEAGas) into the Network through gate stations (which are not owned by AGN). AGN is then contracted by Network Users to transport the natural gas through the Network to the customer delivery point.

The Network comprised 7,950 kilometres of distribution and transmission mains as at 30 June 2014. Table 2.1 shows that the majority of the Network comprises distribution mains that are located in the Adelaide metropolitan area, followed by the larger regional centres of Mount Gambier, Port Pirie and Whyalla. During the year ending 30 June 2014, the Network transported 23 petajoules (22,729 terajoules) of natural gas to 423,436 South Australian natural gas customers (see Table 2.3).

TABLE 2.1: NETWORK LENGTH BY REGION, 30 JUNE 2014

Region	Network Length (kilometres)		
	Distribution	Transmission	Total
Adelaide	7,205	190	**7,395**
South East (including Mount Gambier)	213	1	**214**
Port Pirie	125	5	**130**
Riverland	90	13	**103**
Whyalla	103	-	**103**
Peterborough	5	-	**5**
Total	**7,741**	**209**	**7,950**

The long history of the Network means that it consists of a variety of pipe materials. Up until the 1970s, cast iron (CI) was the main material that was used for natural gas mains, with unprotected steel (UPS) also being used for a period of time. Subsequent to this, polyethylene (PE) has been used as the predominant pipe material, with PE pipes up to 200 millimetres in diameter being commonly used.

Table 2.2 sets out the composition of the Network by pipe material. This shows that the majority of the network consists of PE operating at medium to high pressure. AGN is midway through a mains replacement program aimed at replacing the old CI and UPS network with PE, which will not only maintain safety but also increase the operating pressure (and hence capacity) of the Network (see Chapter 8 for further information on AGN's mains replacement program).

TABLE 2.2: NETWORK COMPOSITION, 30 JUNE 2014

Pipe Material	Network Composition (kilometres)	
	Distribution	Transmission
Cast Iron	834	-
Unprotected Steel	104	-
High Density Polyethylene	2,120	-
Medium Density Polyethylene	3,024	-
Steel Transmission	-	209
Protected Steel	1,658	-
Other	1	-
Total	**7,741**	**209**

Rule 72 of the National Gas Rules (NGR) requires AGN, to the extent it is practicable, to provide a forecast of pipeline capacity and utilisation over the next (2016/17 to 2020/21) AA period. As previously indicated to the Australian Energy Regulator (AER), such parameters are not relevant or have no meaning in the context of a natural gas distribution network. This reflects that the Network consists of a variety of inter-linked pipe materials, each with a different capacity (unlike natural gas transmission pipelines).

The capacity of different sections of the Network is analysed on an ongoing basis. Pressures and flows are simulated in order to ensure that the Network has adequate capacity to meet customer needs. Where modelling or field data (for example telemetry or pressure recorders) indicate that potential capacity or pressure problems exist, mains reinforcement projects or other required actions are instigated to augment network capacity.

The capacity of the Network is continually increasing as a result of the replacement of the low pressure CI and UPS mains with high pressure PE mains. In addition, the ability of the Network to maintain supply in instances of failure is being enhanced through certain security of supply initiatives undertaken in the current and next AA periods (see Chapter 8 for further information on our capital expenditure program which includes our mains replacement plan).

2.2.2 Network Customer Segments

AGN generates its revenue primarily by charging Network Users (i.e. retailers and some large industrial customers) for the provision of natural gas haulage through the Network and for metering and related services (see Chapter 6 for further information on the services provided on the Network). Table 2.3 shows the customer numbers and volume of natural gas delivered to the key regions that are supplied by the Network.

TABLE 2.3: NETWORK CUSTOMER NUMBERS AND VOLUME BY REGION, 30 JUNE 2014

Region	Customer Numbers	Volume (terajoules)
Adelaide	405,091	20,959
Port Pirie	5,290	1,133
Riverland	469	117
South East	8,567	429
Peterborough	72	13
Whyalla	3,947	77
Total	**423,436**	**22,729**

Note: Totals may not add due to rounding.

2.3 Network Ownership

The Network is owned by Australian Gas Networks Limited (formerly Envestra Limited), which is part of the Cheung Kong Hutchinson Group of companies based in Hong Kong. The Cheung Kong Hutchinson Group took effective control of the Envestra Group in August 2014 and subsequently changed the company's name to Australian Gas Networks Limited (AGN).

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 Hutchinson Group, AGN was delisted from the ASX in October 2014.

2.4 Outsourcing Arrangement

AGN outsources the operation of the Network to APA Asset Management (APA) under an Operating and Management Agreement (OMA) entered into in 2007 (the 2007 OMA). The services provided by APA 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.

In consideration for operating the networks, AGN pays for the actual costs incurred by APA in providing the above services (provided those costs are incurred in accordance with strict budgeting constraints), a margin and incentive payments.

The recovery of the margin, referred to in the 2007 OMA as the Network Management Fee (NMF), has been subject to extensive review by the AER in previous AA review processes. Through these reviews it has been decided that the NMF satisfies the relevant requirements of the NGR in all three of AGN's regulated networks: South Australia, Victoria and Albury.[4] The NMF was most recently considered by the AER in the 2013 to 2017 Victorian AA review. In that review the AER found:

> *"The AER considers there is sufficient evidence to suggest that a forecast of opex inclusive of the Network Management Fee (NMF) under Envestra's [AGN's] operating and management agreement with the APA Group [APA] is consistent with the criteria governing operating expenditure under the NGR. In particular, that:*
>
> - *Envestra is acting prudently and efficiently by outsourcing the operation and maintenance of Envestra Victoria and Envestra Albury to the APA Group. This is demonstrated by Envestra's reasonable performance against various benchmarks.*
> - *industry practice is to outsource the operation of networks to take advantage of economies of scope and scale available to asset management companies. Envestra is acting in accordance with good industry practice by outsourcing the operation and maintenance of Envestra Victoria and Envestra Albury to a large asset management company to access these economies of scale and scope.*
> - *the AER considers an indicator of achieving the lowest sustainable cost is efficiency. Envestra's total opex [operating expenditure] has been relatively efficient in the 2008-12 access arrangement period. Therefore, as Envestra's forecast opex is based on historical opex, the AER considers the forecast opex of Envestra Victoria and Envestra Albury inclusive of the NMF is reflective of the lowest sustainable cost of providing reference services."*[5]

The same situation continues to apply in South Australia. Chapters 4 and 7 of this AAI provide benchmarking evidence demonstrating that AGN has productivity levels that are consistent with other (much larger) service providers. We have also updated the margin benchmarking report that has been provided to the AER in previous AA reviews, which shows that the NMF is at the low end of the range of comparable margins earned by similar contractors to APA (see Attachment 2.4).

2.5 AGN's Vision: To Be the Leading Natural Gas Distributor in Australia

AGN aims to be the leading natural gas distributor in Australia (see Figure 2.3). Our definition of leading is to achieve top quartile performance compared with other Australian natural gas distributors on all of our key targets (on the basis that the leading performance will be different across the different measures). The AGN Vision Statement (the Vision) sets out the following three key objectives that we consider are consistent with achieving our vision of 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* – undertaking the required scope/volume of work within the benchmarks set by the AER while growing the network in a prudent and efficient manner.

---

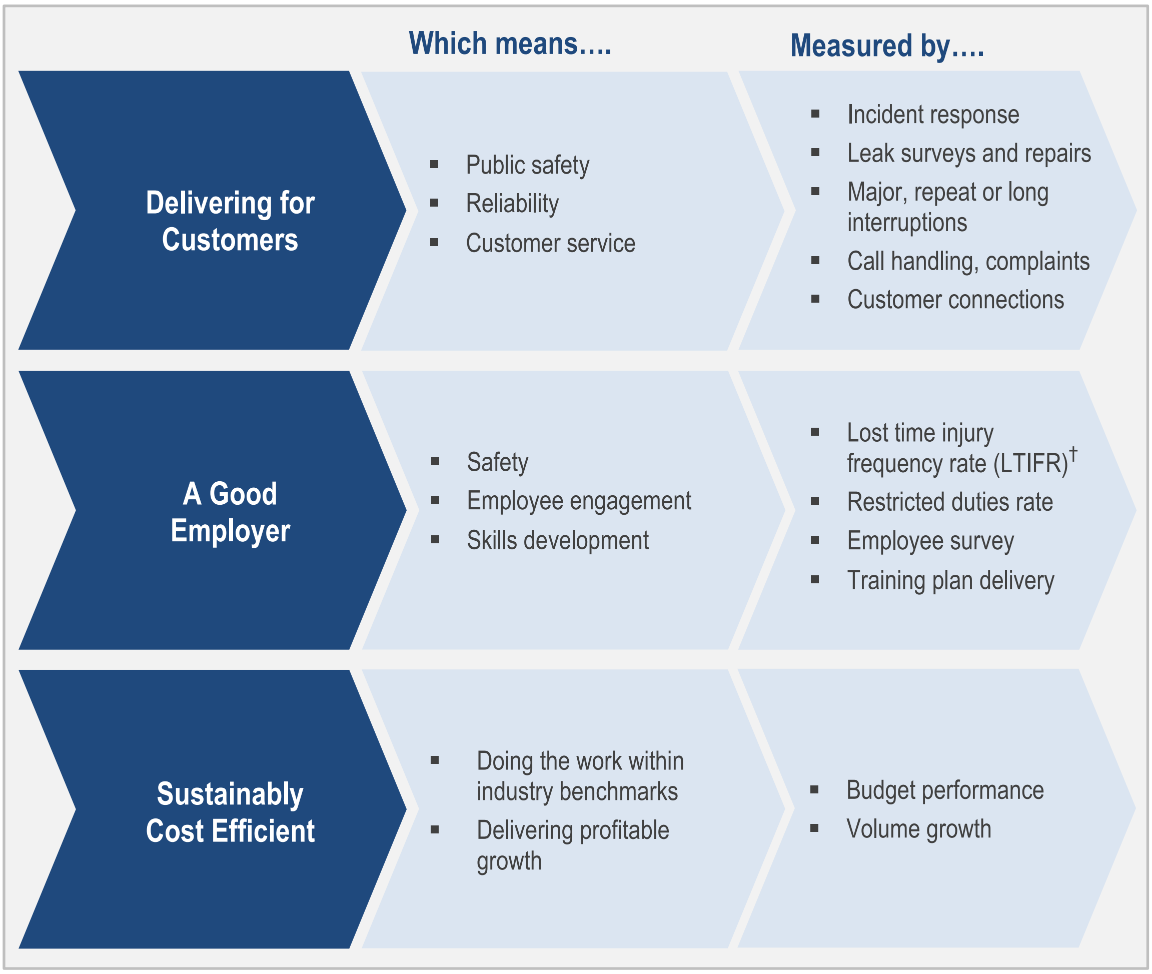
4 In previous AA reviews AGN has provided substantial evidence to explain the history, commercial reasoning and implementation of its OMAs. As this material has been considered in detail in previous AA reviews, AGN will not repeat it in this section but has attached to this AAI the most relevant extracts of this material, being affidavits of Mr. Ian Little (AGN's former Managing Director), Mr. Peter Cain (former Envestra Chief Financial Officer and Company Secretary), and Mr. John Ferguson (APA Group General Manager Networks). These affidavits are set out at Attachments 2.1, 2.2 and 2.3 respectively. The contractual management processes used between AGN and APA, as described in the affidavits, remain current and reflect the procedures that AGN continues to use to ensure the prudent and cost efficient delivery of services by APA.

5 AER 2012, "*Access Arrangement Draft Decision Envestra Ltd. Part 3 Appendices*", September 2012, pg. 132-133.

AGN communicates its Vision to all key stakeholders, such as employees/contractors, governments, regulators, investors and our customers. Importantly, all of the objectives set out in the Vision can be measured, including in most instances against the performance of our industry peers. AGN intends to publicly report on our performance under our Vision and use it to drive ongoing improvements in service delivery.

Our performance over the current AA period against the Vision is set out in the remainder of this chapter.

FIGURE 2.3: AGN'S VISION



† *For full explanation please refer to Section 2.6.2.*

2.6 What We Have Delivered

Figure 2.4 summarises our performance over the current AA period against the targets set out in our Vision Statement. Overall, AGN has met the key safety standards set for the business and delivered the major outputs set by the AER for the current AA period.

FIGURE 2.4: WHAT WE HAVE DELIVERED OVER THE CURRENT ACCESS ARRANGEMENT PERIOD

	Which means….	2011/12 – 2015/16 Actuals/Estimates
Delivering for Customers	▪ Public safety ▪ Reliability ▪ Customer service	▪ Emergency calls: 90% answered in 10 seconds. ▪ Leaks: 95% attended in two hours; 100% repaired within targets set in Leakage Management Procedure (LMP) targets. ▪ Mains survey: 100% compliance with LMP. ▪ Average 15 major interruptions per annum*. ▪ Circa 38,000 new connections. ▪ Stakeholder engagement program implemented.
A Good Employer	▪ Safety ▪ Employee engagement ▪ Skills development	▪ 2014 LTIFR: 1.3 per million hours.† ▪ Increase in employee and contractor employee numbers: 434 in 2011, 648 in 2014.
Sustainably Cost Efficient	▪ Doing the work within industry benchmarks ▪ Delivering profitable growth	▪ 100% CI and UPS mains replacement delivered (1,072 kilometres). ▪ Commenced high-density PE mains replacement (100 kilometres, not in the AER-set benchmarks). ▪ Expanded network to Tanunda and McLaren Vale. ▪ Outperformance: 9% operating expenditure, 12% capital expenditure. ▪ 6% volume underperformance.

* *"Major" means to five or more customers.*

† *For full explanation please refer to Section 2.6.2.*

2.6.1 Delivering for Customers

The provision of a safe and reliable supply of natural gas is the most important driver of business performance. The Asset Management Plan (AMP) is the overarching plan explaining our strategy for ensuring both public and employee safety (see Chapter 8). The AMP provides a consolidated view of a number of technical and operational plans, including:

- *the Leakage Management Procedure (LMP)* – which outlines the process for managing natural gas leaks on the Network; and
- *the Mains Replacement Plan (MRP)* – which outlines the process for managing the replacement of ageing mains.

The key targets in the LMP for managing gas leaks 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.

AGN aims to achieve the key safety targets set out in its Vision Statement for the current AA period. In particular, AGN will:

- answer 90% of all calls to our emergency call centre within 10 seconds of receiving the call;
- attend to 95% of all publicly reported natural gas leaks within two hours (those leaks considered to be higher risk are prioritised as per the procedures set out in our LMP);
- repair all network leaks within the required time periods set out in the LMP; and
- complete routine natural gas leak surveys in the required time periods set out in the LMP.

In terms of our other key deliverables for customers over the current AA period, AGN notes that:

- there have been, on average, only 15 major network interruptions per year (a "*major*" interruption is one that affects five or more customers and was attributable to our actions, asset condition or third-party damage);
- we expect to connect circa 38,000 new customers to the Network (although AGN notes that this is more than 20% less than the target set by the AER for the current AA period, which reduction is driven primarily by lower than anticipated economic activity across the State); and
- we engaged with our customers and key stakeholders regarding, among other things, their willingness to pay for changes in the services provided by AGN (see Chapter 3 for more information on our stakeholder engagement program).

2.6.2 A Good Employer

AGN has achieved industry best practice employee safety levels over the current AA period. Employee safety is typically measured by the lost-time injury frequency rate (LTIFR), which is the number of lost-time injuries (defined as an occurrence that resulted in a fatality, permanent disability or time lost from one day shift or more) over a year relative to the total number of hours worked (usually per million hours worked) in that year. In 2013/14, there were 1.3 lost time injuries per million hours worked.

The employee engagement survey is a new initiative that will be introduced by AGN. We are aiming to design and undertake the survey from 2015/16 onwards, and as such, there is no information on this aspect of performance to report for the current AA period.

2.6.3 Sustainably Cost Efficient

AGN estimates that its actual operating expenditure (opex) and capital expenditure (capex) will be below the benchmarks set by the AER for the current AA period by 9% and 12% respectively. This positive outcome reflects several factors, including:

- the strict cost management practices applied across the business, including in response to the AER Efficiency Benefit Sharing Scheme (EBSS) in the case of our operating expenditure performance; and
- the significant scale of our contractor APA, who is the largest owner/operator of natural gas infrastructure in Australia.

The key drivers of this outperformance are discussed in more detail in Chapter 4 of this AAI.

The estimated reduction in capex has not, however, come at the expense of the delivery of our key asset management programs, particularly in respect of our mains replacement program. AGN is committed to completing the CI and UPS mains replacement program that was endorsed by the AER in its Final

Decision for the current AA period. In its 2011 Draft Decision for the Network, which decision was carried through to the Final Decision, the AER stated that:

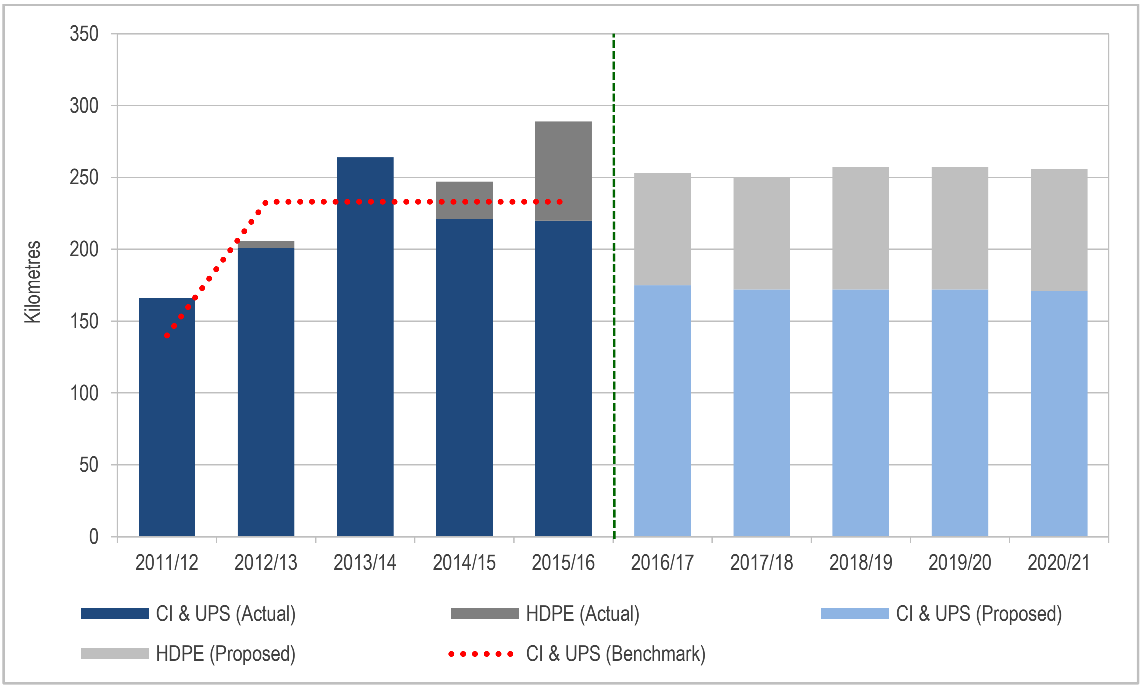
> *"…Envestra [AGN] has established a requirement for the replacement of its cast iron and unprotected steel mains to maintain and improve safety of services and to maintain the integrity of services in accordance with the NGR. The AER has reached this conclusion for a number of reasons. Most importantly, the AER has concerns about the safety risk posed through the leakage of gas from Envestra's distribution network."* [6]

In making this decision, the AER had regard to the endorsement of our mains replacement program by its technical expert, Wilson Cook, as well as submissions from the South Australian Office of the Technical Regulator, the Essential Services Commission of South Australia and the Government of South Australia. The AER at the time did express concern that approving the mains replacement plan, which provided for an acceleration of replacement rates, presented a risk to consumers that AGN would not meet the targets.

AGN has, however, not only delivered on its mains replacement plan but also exceeded it. In the current AA period, AGN is expecting to replace 1,172 kilometres of mains, which is 100 kilometres above the benchmarks set for the current AA period (see Figure 2.5). The additional 100 kilometres reflects the commencement of a program to replace ageing plastic (high-density polyethylene or HDPE) pipe, as these pipes are now reaching the end of their useful life.

The HDPE mains replacement program was not included in the capex benchmarks set by the AER for the current AA period.

FIGURE 2.5: ACTUAL AND BENCHMARK MAINS REPLACEMENT IN SOUTH AUSTRALIA, 2011/12 TO 2020/21



The key benefits derived from the mains replacement program over the current AA period include a:

- 50% reduction in CI and UPS mains and service leaks;
- 36% reduction in CI mains breaks;

---

[6] AER 2011, "*Envestra Ltd: Access Arrangement Proposal for the SA Gas Network, 1 July 2011 – 30 June 2016*", Draft Decision, February 2011, pg. 28.

- 60% reduction in customer reported supply complaints related to water in mains; and
- 34% reduction (or 730 terajoules) in unaccounted for gas (UAFG), of which a material proportion is natural gas losses on the Adelaide network.

With regard to the last point, AGN estimates that actual UAFG volumes will be 20% below the benchmark UAFG volumes by the end of the current AA period.

AGN is committed to continuing with its mains replacement program in the next AA period (see Section 5.5.1 and Chapter 8 of this AAI).

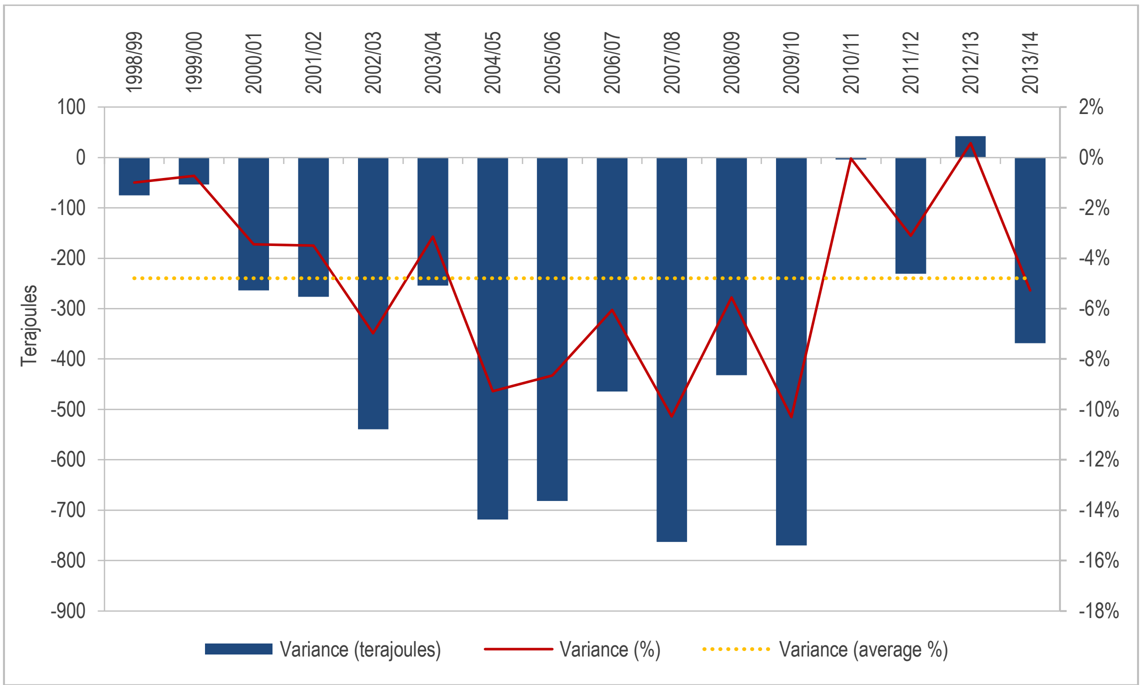
AGN is also expanding the footprint of the Network over the current AA period to the following two towns:

- *Tanunda* – which is 75 kilometres north of Adelaide and has the potential for 1,500 new customer connections; and
- *McLaren Vale* – which is 40 kilometres south of Adelaide and has the potential for a further 1,500 new customer connections.

The NGR allows customer connections to the network if "*the overall economic value of the expenditure is positive*" (Rule 79(2)). This means that the incremental revenue generated from connecting the customer must exceed the cost of that customer connection. Given this, expansions to the Network, such as that which has occurred in Tanunda and the McLaren Vale, will lead to lower prices than would otherwise have applied to existing customers on the Network.

AGN has, however, again been unable to achieve the volume benchmarks set by the AER. This has been a persistent trend over the past 16 years. For example, actual residential volumes have only exceeded benchmark volumes once over the past 16 years (see Figure 2.6). The inability to achieve benchmark volumes is primarily driven by average annual residential consumption falling at a faster rate than assumed by the benchmarks.

FIGURE 2.6: BENCHMARK AND ACTUAL RESIDENTIAL VOLUMES, 1998/99 TO 2013/14



Note: Variance is calculated as actual less allowed (benchmark)consumption.

This decline in average annual consumption is due to a range of factors, including warming weather trends, continuous improvements in energy efficiency (appliance efficiency and building thermal efficiency), customer appliance preferences (electric reverse-cycle air-conditioning instead of natural gas space heating) and the significant installation of solar equipment in homes in recent years. AGN notes that there are a range of emerging pressures that will place further pressure on the average consumption of our customers, including:

- further substantial increases in renewable generation – a high penetration of 'green' electricity reduces the environmental driver for customers to use natural gas;
- emergence of new technologies – including continual technological improvements in distributed generation, battery storage and electric vehicles (which will reduce the unit price of electricity by resulting in a step change in volumes and/or make consumers more electricity focused in their appliance choice/use);
- further increases in the penetration rates of reverse-cycle air-conditioners – which reduces the up-front cost of switching from natural gas to electricity; and
- a move to cost-reflective electricity network prices – in areas with a peak summer load, such as South Australia, electricity tariffs would increase during peak times in summer and decrease in off-peak times in winter (i.e. during periods of peak (winter) gas demand).

Our resultant demand forecasts, which are discussed in Chapter 14, are based on historic trends. AGN is concerned that there remains downside risk to these forecasts, given there are several new factors that are not in the historic trends, the impacts of which cannot be accurately forecast. AGN therefore considers that:

- there remains considerable risk that AGN will, once again, not be able to achieve the benchmark volumes; and as such
- should the demand forecasts be increased, AGN would consider moving to revenue cap regulation rather than price cap regulation for the next AA period.

The key reason that AGN has not proposed a revenue cap form of regulation at this stage is that, given gas is a fuel of choice, price cap regulation places a stronger incentive on business growth (because revenue increases if natural gas sales increase under price cap regulation). AGN will, however, continue to consider this issue, particularly given actual revenue will be around $57 million less than benchmark revenue in the current AA period as a result of relatively low actual volumes (AGN would have recovered this ‘lost’ $57 million had a revenue cap applied).

2.7 Summary

AGN is one of the leading natural gas distribution businesses in Australia, with around 1.2 million customers across most states and territories in Australia. AGN is owned by the Cheung Kong Hutchinson Group of Companies based in Hong Kong. AGN has 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.

AGN has delivered strong performance in South Australia over the current AA period. This includes meeting all key safety targets governing the supply of natural gas, providing high levels of network reliability and best-practice levels of employee safety. AGN has delivered the key projects that were funded over the current AA period within the benchmarks that were set by the AER. Unfortunately, AGN has, however, been unable to recover benchmark revenue due to lower than forecast natural gas volumes.

AGN intends to build on this strong performance over the next AA period, as explained in the remainder of this AAI.

Page intentionally left blank

3 Stakeholder Engagement

Page intentionally left blank

3 Stakeholder Engagement

3.1 Introduction

Australian Gas Networks Limited (AGN) is committed to operating our networks in a manner that is consistent with the long-term interests of consumers. To achieve this, we have designed and implemented a robust stakeholder engagement program to inform the initiatives described in this Access Arrangement Information (AAI). This chapter explains the four key phases of our stakeholder engagement program.

Importantly, the outcomes of this stakeholder engagement program have been used to inform, but not drive, the initiatives/business cases set out in the AA proposal. In other words, all proposals have a sound asset management/planning foundation and stakeholder engagement results are used to provide directional support – for example, over the scale and/or scope of the program.

The following chapters of this AAI explain in more detail how the stakeholder engagement outcomes have impacted on our plans for the next (2016/17 to 2020/21) Access Arrangement (AA) period.

3.2 Objective of Our Stakeholder Engagement Program

As explained in Chapter 2, AGN aims to be the leading natural gas distributor in Australia. A key input into achieving this aim is to effectively engage with a range of internal and external stakeholders of the business. AGN has sought to design our approach to stakeholder engagement such that it is consistent with promoting the National Gas Objective (NGO) and the Australian Energy Regulator's (AER's) *Consumer Engagement Guideline for Network Service Providers (*referred to as the AER's Consumer Engagement Guideline*)*.

Our stakeholder engagement program is not solely for the purpose of the AA process. We are committed to stakeholder engagement as a business-as-usual activity that will continue for the duration of the next AA period. We have also committed to report to stakeholders annually on our performance against the AGN Vision Statement (as outlined in Chapter 2).

3.2.1 National Gas Objective

The NGO, which is set out in Section 23 of the National Gas Law (NGL), states that:

> *"The objective of this [National Gas] Law is 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 of natural gas."*

Effective engagement with our stakeholders is key to assisting AGN better understand their values, which will enable AGN to better promote "*the long term interests of consumers of natural gas*".[7]

3.2.2 AER Consumer Engagement Guideline

The AER's Consumer Engagement Guideline provides a high level framework to help businesses like AGN integrate stakeholder engagement into business as usual operations.[8] The framework is centered around the following key components:

[7] National Gas Law, Section 23.

[8] AER 2013, "*Better Regulation Consumer Engagement Guideline for Network Service Providers*", November 2013.

- *principles* – adhering to a set of best-practice principles to guide effective stakeholder engagement, which includes the need for engagement to be clear, accurate and timely; accessible and inclusive; transparent and measurable (see Figure 3.1);
- *priorities* – the need to identify the issues and priorities for stakeholder engagement to ensure we understand and incorporate stakeholder views into business planning, recognising that stakeholders have diverse views;
- *delivery* – setting the manner by which stakeholder engagement will occur for different stakeholder groups, including through holding stakeholder workshops and focus groups;
- *results* – articulating the outputs of stakeholder engagement and how this has impacted on business planning; and
- *evaluation and review* – implementing a robust process to identify areas for continuous improvement.

The four key phases of our stakeholder engagement program have been designed to be consistent with this framework.

FIGURE 3.1: STAKEHOLDER ENGAGEMENT PRINCIPLES

Clear, accurate and timely communication

The objective of this principle is to ensure that stakeholders are provided sufficient information on which to base meaningful feedback and to ensure two-way communication. To achieve this AGN will:

- Provide stakeholders with clear, accurate, relevant and timely information, having consideration of stakeholders' preferred communication methods.
- Establish clear and realistic timeframes for stakeholder input.
- Ensure any documentation provided is clear, concise and uses plain English.
- Understand stakeholder preferences for communication methods and implement an approach consistent with these preferences.

Accessible and inclusive

The objective of this principle is to ensure AGN has access to insights from all stakeholders and that engagement is ongoing. To achieve this AGN will:

- Identify all relevant stakeholder cohorts and the specific characteristics of each group, such as their preferred method of communication.
- Be efficient with the engagement, having regard for stakeholders' time.
- Ensure each stakeholder or stakeholder group has an appropriate understanding of relevant issues on which to base feedback.
- Give stakeholders choices and engage in a non-leading manner.
- Develop and publish a plan for engaging beyond the submission of an AA Proposal.

Meaningful Engagement

Transparent

The objective of this principle is to ensure stakeholders have a clear understanding of their role and also for AGN to be transparent with the community. To achieve this AGN will:

- Clearly identify the objectives of each phase of engagement.
- Clearly explain the role of stakeholders in each phase of engagement.
- Identify and explain how stakeholder input and insights will be relied upon.
- Clearly and credibly report the input of all stakeholders including how insights have been incorporated into Business Plans.

Measurable

The objective of this principle is to ensure AGN is accountable for its stakeholder engagement program. It provides a mechanism for AGN to understand the effectiveness of the program and to use this information to improve over time. To achieve this AGN will:

- Develop, implement and report on feedback relating to our engagement strategy and activities.
- Develop systems to track performance over time and publish the results in a timely manner.

3.3 Development of our Stakeholder Engagement Program for South Australia

Key to the design and implementation of our stakeholder engagement program has been the establishment of our external Reference Groups and the engagement of an independent expert advisor.

3.3.1 External Reference Groups

One of the first actions taken by AGN was to establish the following two external Reference Groups:

- *the AGN Reference Group* – which comprises representatives from a broad cross section of key community stakeholder groups, including representatives from the local government, business, property and welfare sectors; and

- *the Retailer Reference Group* – which comprises representatives from those retailers that retail natural gas in the South Australian market.

The composition of the two external Reference Groups is shown in Figure 3.2. 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 have been involved in all phases of our program (the specific involvement of each Reference Group is discussed in this chapter where relevant).

FIGURE 3.2: EXTERNAL REFERENCE GROUPS

3.3.2 Engagement of an Independent Expert Advisor

Another key component of our stakeholder engagement program was engaging Deloitte as an independent expert advisor to assist AGN to develop and implement its stakeholder engagement program. The key role of Deloitte included:

- ensuring the AGN stakeholder engagement strategy was comprehensive and in line with the objectives set out in Section 3.2;
- designing and facilitating research activities to ensure robust stakeholder feedback was received; and
- accurately capturing and transparently reporting the outcomes of the research activities.

The key output from Deloitte was the 2015 *Australian Gas Networks Stakeholder Insights Report* (the Deloitte Insights Report), which is referred to throughout this chapter and AAI more generally.

3.4 Approach to Stakeholder Engagement

Figure 3.3 sets out the four phases of our stakeholder engagement program. They include:

1. *Strategy Phase* – which involved the development of an overarching Stakeholder Engagement Strategy, our more specific Stakeholder Engagement Strategy for South Australia and our dedicated stakeholder engagement website (which can be accessed at: http://stakeholders.agnl.com.au);
2. *Research Phase* – which involved holding five community workshops and numerous interviews with key stakeholders, with results distilled into 14 key stakeholder insights captured by Deloitte and published in the Deloitte Insights Report;
3. *Implementation Phase* – which involved internal review of the feedback received during the research phase, culminating in the AGN *Insights and Implementation Report* and this AA Proposal for South Australia; and
4. *Ongoing Engagement Phase* – which involves a commitment by AGN to continually seek ways to improve our stakeholder engagement program and also to engage with our stakeholders on an ongoing basis.

All outputs and source material for our stakeholder engagement program are available on our dedicated stakeholder engagement website. A list and description of all documents hosted on this website (http://stakeholders.agnl.com.au) is provided in Attachment 3.1.

Each phase of our stakeholder engagement program is described in more detail in the remainder of this chapter.

FIGURE 3.3: AGN'S APPROACH TO STAKEHOLDER ENGAGEMENT

Strategy

The Strategy Phase defines, for each region, who we will engage with, how we will engage, the key issues that will be subject to consumer engagement and how we will track the success of our program.

This Phase in itself involves significant engagement, such as:

- workshops with relevant internal stakeholders to scope potential issues and approaches to stakeholder engagement; and
- workshops with our key Reference Groups that have been established to guide our approach along with other key stakeholders, including the AER, AER Consumer Challenge Panel, state governments, state-based regulators and various representative community groups to develop the stakeholder engagement program for a particular region.

Research

The Research Phase involves the implementation of the region-specific strategy determined in the Strategy Phase. This includes:

- designing location specific engagement activities (such as workshops and interviews);
- preparing clear information that will assist stakeholders participate effectively in our engagement activities (for example fact sheets);
- conducting research (generally with the assistance of an independent expert, facilitating workshops, holding one-on-one meetings and collating/analysing results); and
- capturing and reporting on customer insights.

Implementation

Insights from the Research Phase will then be considered by AGN in the preparation of AA Proposals and Plans more generally. Activities include:

- internal workshops to understand stakeholder insights;
- business planning and modelling to adjust plans as appropriate to incorporate insights from the engagement program;
- reporting in a clear and transparent manner how insights have been factored into our AA Proposal and Business Plans; and
- further stakeholder engagement on understanding stakeholder insights where appropriate.

Ongoing Engagement

This Phase involves:

- reporting on the outcomes/effectiveness of previous engagement activities;
- incorporating lessons learnt into future engagement programs; and
- continually engaging with stakeholders beyond the development of the AA Proposal.

Activities during this Phase include:

- updating of relevant information on our dedicated interactive engagement website;
- release/updating of educational materials explaining investment decisions; and
- periodic engagement with key stakeholders to understand their issues and key values (i.e. continual research).

3.5 Strategy Phase

The objective of the Strategy Phase was to develop a robust approach to stakeholder engagement for South Australia. The key steps in this process included developing our Scoping Paper, engaging with stakeholders on our Scoping Paper and strategy more generally and considering this feedback in developing our South Australian Stakeholder Engagement Strategy.

The Scoping Paper (Attachment 3.2) sets out our preliminary views on who our key stakeholders are and the potential issues for engagement. To this end, the Scoping Paper notes that:

> *"One of the first steps in designing our stakeholder engagement strategy is to better understand who Envestra's [AGN's] key stakeholders are and what we should consult on, which is the focus of this Scoping Paper. We will then use this information to develop a Stakeholder Engagement Strategy, which will be implemented over the October through December 2014 period."*[9]

AGN invested significant time into developing and engaging on its Scoping Paper. This reflected the importance the business placed on ensuring that its stakeholder engagement strategy was well designed and targeted. This included ensuring our strategy captured and considered all relevant stakeholders and properly identified the key issues on which different stakeholders wanted to engage with AGN. The Scoping Paper had the following two sections:

9 AGN 2014, "*AGN Stakeholder Engagement Scoping Paper*", pg. 2. Provided as Attachment 3.2 to this AAI.

- *who are our external stakeholders* – where AGN sought to define all relevant stakeholders in respect of the South Australian natural gas distribution network (the Network); and

- *what are our engagement themes* – where AGN sought to broadly define all potential topics that could form part of our engagement program and listed the potential matters where AGN would need to inform stakeholders to facilitate effective engagement.

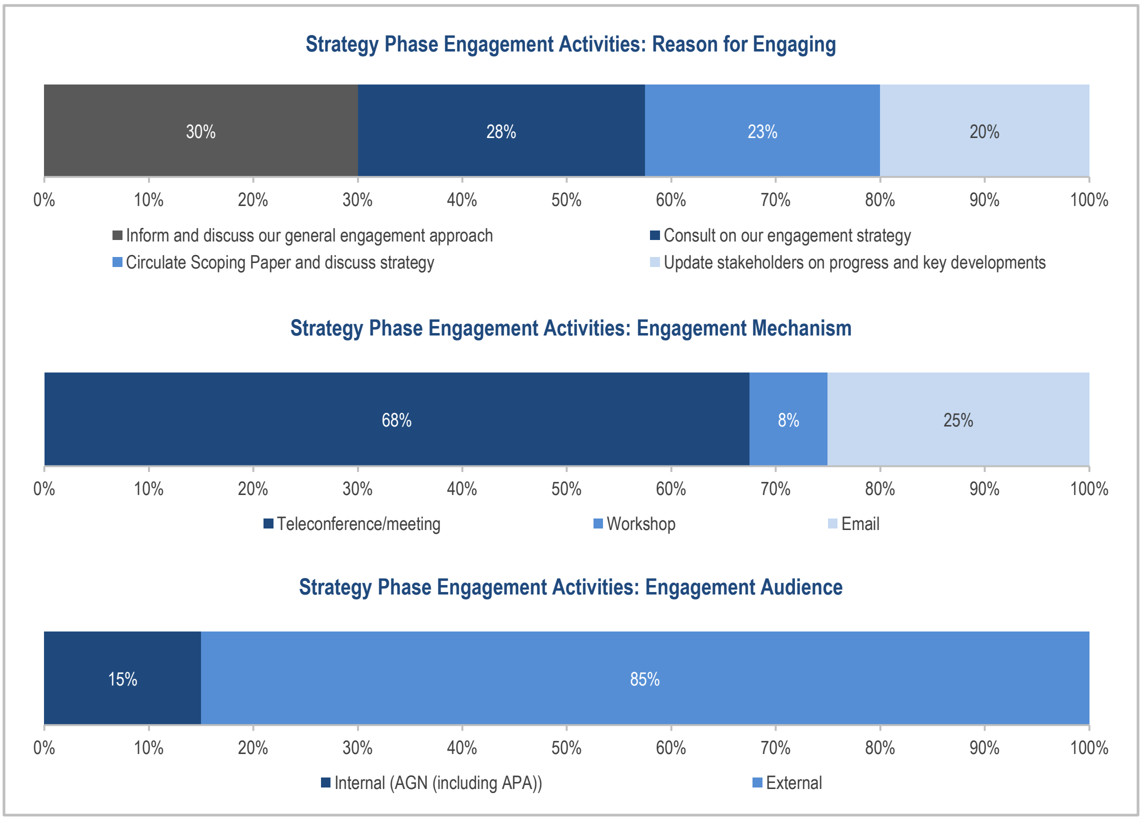
The Scoping Paper facilitated an extensive stakeholder engagement process with a range of stakeholders, including the AER, Essential Services Commission of South Australia (ESCOSA), South Australian Office of the Technical Regulator (OTR), South Australian Government, Energy Retailers Association of Australia (ERAA) and the AER's Consumer Challenge Panel (CCP). With the exception of the CCP, AGN met with each of these mentioned parties to discuss the Scoping Paper and associated feedback.

3.5.1 Engagement during the Strategy Phase

During the Strategy Phase, AGN participated in and/or facilitated 40 instances of engagement with internal and external stakeholders using a range of approaches. Figure 3.4 outlines the breakdown of engagement activities by reason, engagement mechanism and stakeholder group. This Figure illustrates that the majority of the engagement during the Strategy Phase was with external stakeholders.[10]

This section explains in more detail the nature of our engagement with ESCOSA and our two Reference Groups.

FIGURE 3.4: STAKEHOLDER ENGAGEMENT, STRATEGY PHASE



Note: Totals may not add due to rounding.

[10] A log of AGN's external engagement activities is provided as Attachment 3.3 and meeting summaries, which were ratified by the relevant stakeholder, are provided as Attachment 3.4 to this AAI.

3.5.1.1 Engagement with ESCOSA

The AGN Reference Group was formed as a sub-committee of ESCOSA's Consumer Advisory Committee (CAC). The CAC provides advice to ESCOSA on how its regulatory functions impact on consumers:

> *"The Commission [ESCOSA] has established a Consumer Advisory Committee comprising representatives of water, sewerage, electricity and gas consumers. The Consumer Advisory Committee provides advice to the Commission in relation to its water, sewerage, electricity and gas licensing functions, and provides advice on other matters relating to those industries to the extent that such issues and functions impact on consumers.*
>
> *Membership of the Consumer Advisory Committee is drawn from peak bodies representing a wide range of interests including disadvantaged consumers, rural and remote consumers, Local Government, environmental interest groups and industry and business generally."* [11]

AGN therefore initially engaged with ESCOSA on the use of the CAC as one of our key Reference Groups. AGN also notes and appreciates the administrative support provided by ESCOSA for the AGN Reference Group. ESCOSA has rightly advised that, following this AA review process, AGN will need to establish its own advisory committee separate from the CAC (but might include some of the same representatives). AGN agrees with this view and has included this initiative in its AA Proposal.

ESCOSA is responsible for developing the customer service and reliability standards that are to apply over the next AA period. AGN has actively engaged with ESCOSA on these standards. To this end, ESCOSA, noted in its Draft Decision on the service standards to apply in South Australia over the next AA period that:

> *"While AGN's stakeholder engagement program has canvassed a broad range of issues beyond the scope of this review, the Commission has worked with AGN, including making the Consumer Advisory Committee available to AGN for regular briefings and input, to ensure that the stakeholder engagement program tested several matters relevant to the current review. This included AGN testing whether its customers were willing to pay for:*
>
> - *changes to AGN's current gas leak responsiveness*
> - *changes to AGN's current call centre responsiveness, and*
> - *the introduction of a GSL [Guaranteed Service Level] Scheme".* [12]

The outcomes of the engagement program as it relates to service standards is discussed in more detail in Section 3.7.2.

3.5.1.2 Engagement with the AGN Reference Group

AGN held two workshops with the AGN Reference Group as part of the process of developing our stakeholder engagement strategy. The AGN Reference Group advised that AGN should engage with stakeholders who are affected by our business but are not necessarily gas consumers. The Reference Group also stressed the importance of engaging with the regions served by the Network, a point that was also made by the AER.

The AGN Reference Group made it clear that stakeholders will need certain information before participating in any research activities, including:

- information about the natural gas supply chain, including identifying those elements that AGN can and cannot control;

---

[11] See: http://www.escosa.sa.gov.au/consultation/consumer-advisory-committee.aspx.

[12] ESCOSA 2015, "*Draft Decision on Australian Gas Networks Jurisdictional Service Standards for the 2016-2021 Regulatory Period*", March 2015, pg. 10. Provided as Attachment 3.10 to this AAI.

- describing the regulatory regime that applies to AGN's operations;
- describing the components of a retail natural gas bill;
- providing our best estimate of changes in forecast retail prices over the next AA period as relevant context for stakeholders in deciding whether they were willing to pay for certain initiatives to be proposed by AGN;
- providing stakeholders with the option of increases in service and supply reliability levels for a price increase and a decrease in service and supply reliability levels for a price reduction; and
- providing stakeholders with sufficient information regarding any proposed initiatives so that informed judgements could be made.

Members of the AGN Reference Group attended certain research activities so they could see first hand how AGN performed with regard to the above (AGN also notes that other stakeholders also observed aspects of our engagement, including a member of the AER CCP who attended one of our workshops). AGN also met separately with Reference Group members regarding issues that were specific to the members they represent.

3.5.1.3 Engagement with the Retailer Reference Group

The focus of our engagement with the Retailer Reference Group was around the specific issues that should form part of our research. The identified issues included the terms and conditions governing access to the Network, tariff structures and our approach to addressing the affordability issues of certain customer groups (who are often referred to as vulnerable customers).

3.5.2 South Australian Stakeholder Engagement Strategy

The Scoping Paper continually evolved as we received stakeholder feedback. Ultimately, this feedback was used to develop a robust stakeholder engagement strategy that set out our approach to engagement in South Australia, which included:

- The *AGN Stakeholder Engagement Strategy* – which sets out our overarching approach to stakeholder engagement across all of the gas distribution networks owned by AGN (see Attachment 3.5); and
- The *AGN South Australian Stakeholder Engagement Strategy* – which describes how AGN will undertake stakeholder engagement in South Australia (see Attachment 3.6).

The South Australian Stakeholder Engagement Strategy set out specifically how and when AGN intended on undertaking the Research Phase of its engagement program, including who we will consult with and how we will consult (Section 3.5.2.1) and the key themes/issues of that engagement (Section 3.5.2.2).

The South Australian Stakeholder Engagement Strategy also identified the key performance indicators (KPIs) that AGN intends to use to measure its engagement activities (Section 3.8.1).

3.5.2.1 External Stakeholder Engagement Approach

The feedback received from our external stakeholders, primarily on our Scoping Paper, was key to ensuring we had a robust understanding of who the stakeholders are that we should be engaging with and the best way to engage with a particular stakeholder group.

Table 3.1 summarises the relevant stakeholder groups and how they would be involved in our stakeholder engagement program.

TABLE 3.1: EXTERNAL STAKEHOLDER ENGAGEMENT APPROACH

Stakeholder Group and Segment	Research Method				
	Initial Consultation	Ongoing Communication	Deep Dive Interviews	Consultation Workshop	Online Survey
Regulators: – AER – CCP – ESCOSA – South Australian OTR	●	●			
Energy Intermediaries: – The Australian Energy Market Commission (AEMC) – The Australian Energy Market Operator (AEMO)		●			
Government: – State government – Local government – Local councils	●	●			
Non-government Organisations: – South Australian Energy and Water Ombudsman (EWOSA) – Environmental groups – Consumer advocacy groups	●	●	●		
Network Users and Consumers:					
– Residential, commercial/ /business, vulnerable customers			●		●
– Large industrial		●	●		●
– Energy retailers	●	●	●		
Potential Consumers: – Non-gas users – Former gas users				●	●
Network Facilitators: – Plumbers/ gas fitters – Builders/ developers – Appliance retailers/ manufacturers				●	●

3.5.2.2 Engagement Themes

The engagement process on the Scoping Paper, and on our strategy more generally, identified several key themes for engagement (see Figure 3.5). AGN developed a series of research objectives relevant to each theme, again based on the feedback received on the Scoping Paper. Table 3.2 sets out the theme, related research objective and the relevant stakeholder group to be consulted on each theme during the Research Phase of the stakeholder engagement program.

FIGURE 3.5: THEMES FOR CONSULTATION

- Customer experience
- Network safety and reliability
- Network expansion and innovation
- Access and affordability
- Environmental commitments and reporting

TABLE 3.2: RESEARCH OBJECTIVES

Theme and Research Objective	Stakeholders			
	Major Customers	Network Users & Consumers	Potential Consumers	AGN Reference Group
Customer Experience				
Level of awareness of AGN and associated brands (i.e. Natural Gas and/or Envestra)	✓	✓	✓	
Use and reliance on gas	✓	✓		
Customer service experience rating	✓	✓	✓	
Topics and channels for communication	✓	✓	✓	✓
Willingness to pay for a guaranteed service level scheme		✓		
Willingness to pay for changes in AGN's response to general enquiry phone calls		✓		
Willingness to pay for changes in AGN's response to gas leak reports		✓		
Willingness to pay for better coordinated capital works	✓	✓	✓	
Network Safety and Reliability				
Willingness to pay for fire shut-off valves being rolled-out to non bush fire zones	✓	✓	✓	
Willingness to pay for AGN to repair customer outlet service leaks	✓	✓	✓	
Phasing of mains replacement program and a willingness to pay for changes to this phasing		✓		
Willingness to pay for AGN to replace above ground plastic pipes and old fittings	✓	✓	✓	
Willingness to pay for AGN to relocate meters on altered properties	✓	✓	✓	
Willingness to pay for AGN to replace meters inside buildings and inlet services under buildings		✓		
Network Expansion and Innovation				
Willingness to pay for major network expansions	✓	✓		
Willingness to pay for remote meter reading devices		✓		
Access and Affordability				
Forecast price path – understanding stakeholders' price tolerance/elasticity of demand	✓	✓		✓
What do stakeholders think AGN's role should be with respect to vulnerable customers?	✓	✓	✓	✓
Understanding the reasons why people are not connected to mains gas			✓	
Do network users and consumers want a different network tariff structure?	✓	✓		
Environmental Commitments and Reporting				
Stakeholder expectations with respect to environmental transparency	✓	✓	✓	
AGN's role with respect to the environment	✓	✓	✓	✓

3.6 Research Phase

The objective of the Research Phase was to develop a better understanding of stakeholder values through the implementation of the engagement strategy. The South Australian stakeholder engagement strategy noted that:

> *"The key research tools will comprise the workshops and stakeholder interviews. During these processes, key topics such as the natural gas supply chain, regulatory process, and our proposed initiatives can be discussed in detail to ensure informed feedback is received."*[13]

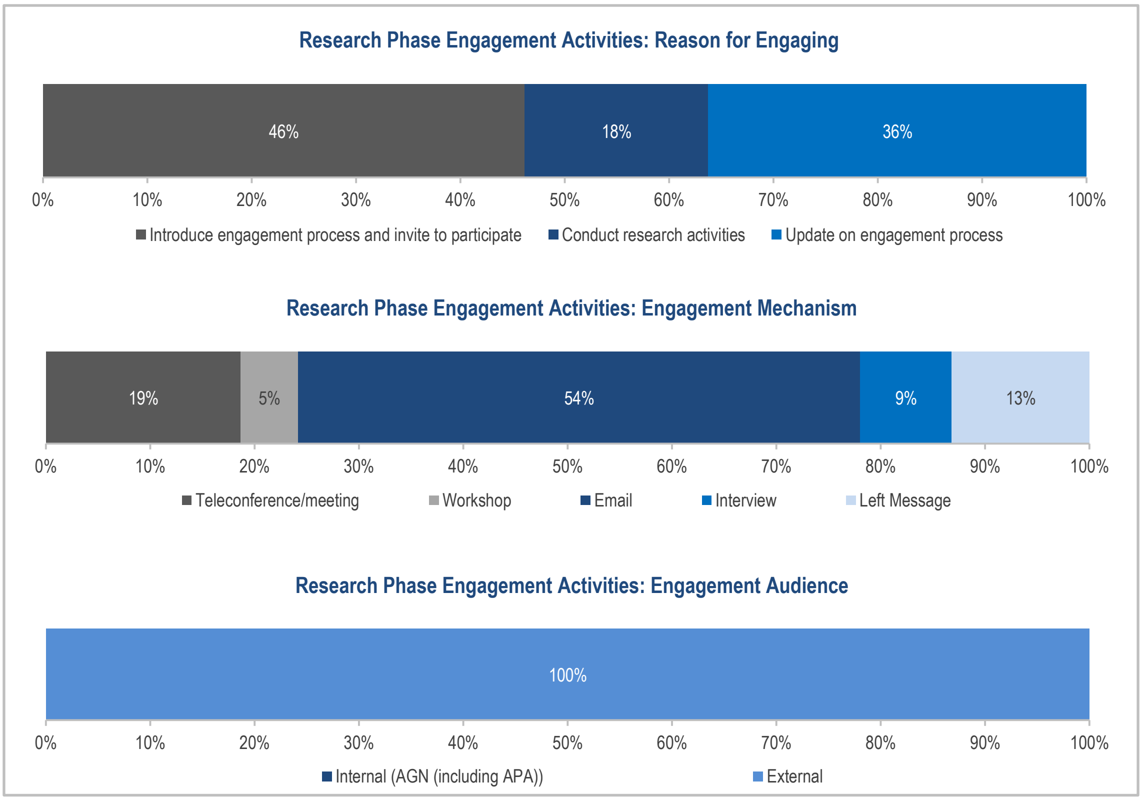
The key steps in this process included engaging with stakeholders on the research objectives identified in the Strategy Phase (Table 3.2), including through a series of stakeholder workshops, interviews and an online survey. The key output from this phase was a report from Deloitte capturing the feedback from our stakeholder engagement program.

This section describes the deliberative workshops held by AGN, the dedicated stakeholder interviews and the online survey that AGN also undertook.

3.6.1 Engagement during the Research Phase

The Research Phase sought to understand stakeholder values using a range of qualitative and quantitative methods. There were around 90 instances of engagement during this phase, almost half of which related to advising our large customers of the engagement program and inviting them to participate (see Figure 3.6).[14]

FIGURE 3.6: STAKEHOLDER ENGAGEMENT, RESEARCH PHASE



Note: Totals may not add due to rounding.

[13] AGN 2014, "*South Australian Stakeholder Engagement Strategy*", December 2014, pg. 12. Provided as Attachment 3.6 to this AAI.

[14] A log of AGN's external research activities is provided as Attachment 3.3 and key meeting summaries and action items, which were ratified by the relevant stakeholder, are provided as Attachment 3.4 to this AAI.

3.6.1.1 Stakeholder Workshops

The key inputs into the Research Phase were the deliberative workshops held with gas consumers and key advocacy groups.

AGN held two workshops with natural gas consumers in metropolitan Adelaide and, consistent with the advice from the AGN Reference Group and the AER, two workshops in major regional centres (Port Pirie and Mount Gambier). Workshop participants were recruited on the basis of gender, age, household income and concession availability to ensure a representative sample of natural gas consumers. Overall, 54 participants attended the workshops.[15]

Deloitte assisted with the design and delivery of the workshops. Deloitte also led the facilitation of the workshops while representatives from AGN and the APA Asset Management (APA) provided the content relating to the AA Proposal. The deliberative workshops were designed to:

- explain the role of AGN in the natural gas supply chain, including explaining those matters that AGN can and cannot control;
- explain the composition of a typical retail natural gas bill and our best estimate of changes to the retail natural gas bill over the next AA period (which provided the relevant context for when participants were asked if they were willing to pay for higher/lower services);
- 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 the willingness to pay of workshop participants for certain initiatives proposed by AGN for the next AA period; and
- facilitate open discussion on key topics such as the environment, vulnerable customers and tariff structures.

AGN held a further workshop at which 12 members from key advocacy groups attended. The purpose of this workshop was to discuss the findings from the four consumer workshops and to seek direct input on workshop topics on behalf of the communities that they represent.

A key feature of these workshops was the significant debate and discussion with and among participants at all the workshops. An example of the presentation provided at a workshop held in December 2014 is provided at Attachment 3.7. The information sheets provided to workshop participants to facilitate informed discussion are available on our dedicated stakeholder engagement website and are also set out in Attachment 3.8.

There were observers at the workshops from ESCOSA, Business SA, the OTR and the AER CCP.

3.6.1.2 Stakeholder Interviews

AGN supported the workshops with dedicated interviews with a range of stakeholders, including our major customers, retailers, and key advocacy groups. These interviews were in some cases held with members of our Reference Groups where, for example, this was required for confidentiality reasons (which was an issue for retailers) or there was a particular issue that an interest group wanted to discuss in greater detail with AGN.

---

15 In line with standard market research practices, all participants received an incentive for their time. Given businesses were harder to recruit than residents, they were offered a higher incentive. Incentive amounts were $100 for residents and $130 for business.

Through the Strategy Phase, AGN identified that targeted interviews were the most appropriate form of engagement with our large customers. AGN contacted around 30 of our largest (industrial) consumers to seek their interest in participating in our engagement program through a dedicated interview, which led to three interviews being held. This reasonably low level of interest is of no surprise given that AGN is in regular contact with these large consumers through business-as-usual operations.

In addition to the three large user interviews, AGN also engaged in:

- three interviews with retailers to discuss tariff structures and/or hardship/vulnerable customer programs;
- three interviews with consumer advocacy groups (the Conservation Council SA, The Multicultural Society of South Australia and Uniting Care Wesley Country SA); and
- an interview/meeting with EWOSA.

Where appropriate, Deloitte attended these interviews and summarised findings. Where Deloitte was unable to attend they were provided with a meeting summary by AGN which had been approved by the interviewed party. The feedback received from these interviews was therefore incorporated into the Deloitte Stakeholder Insights Report). [16]

3.6.1.3 Online Survey

AGN also conducted an online survey in an attempt to augment the workshop findings by involving, at a lower cost, a larger number of stakeholders. The content of the survey was similar to the workshops. The survey included a series of questions about demographics, awareness of AGN, communication preferences and willingness-to-pay initiatives. AGN promoted the survey on its dedicated stakeholder engagement website, in the South Australian newspaper: *The Advertiser* (online and print), in three regional newspapers and on social media.

Over the course of the survey period AGN received 247 completed surveys, 165 of which were from South Australian stakeholders and of whom 124 were natural gas consumers.[17] Deloitte found that the survey response rate was not statistically significant. Despite this, Deloitte was still able to rely on the survey results in its report to AGN:

> *"The results indicate that survey respondents understood what was being asked of them (ie they understood the proposed initiative) but they weren't clear on why they should pay, which points to a lack of understanding of the regulatory model. This lack of understanding is likely due to the fact that survey participants were not afforded the opportunity to engage with AGN subject matter experts on how the proposed initiative interacts with the gas supply chain, the application of the regulatory model and the future price path.*
>
> *However, the survey data does provide an indication of the underlying reluctance of the broader public to pay for additional services, and therefore the importance of education and context (as supplied in the workshops) on AGN when seeking customer feedback for future initiatives.*
>
> *With this in mind, we have based our insights primarily on the findings from the workshops, relying on survey data only in instances where a clear understanding of the regulatory*

[16] It is noteworthy that the Deloitte Stakeholder Insights Report (Attachment 3.9) refers to seven stakeholder interviews. This is because three of the interviews were completed after the cut-off date for information to be incorporated into Deloitte's report. All 10 interviews were considered by AGN in the development of this Revised AA Proposal.

[17] It is noteworthy that AGN has operations in five states and territories of Australia. As a result, during this phase we were interested in hearing from stakeholders from across the nation. However, for the purposes of the development of this Revised AA Proposal, only surveys from South Australian's were used.

model is not required, such as general experience questions. Reported levels of customer support throughout the report refer to workshop data unless otherwise specified." [18]

3.6.2 Deloitte Stakeholder Insights Report

The Deloitte Stakeholder Insights Report, which is provided as Attachment 3.9 to this AAI, captured all the stakeholder feedback from the Research Phase. Deloitte distilled this feedback into 14 stakeholder insights, which are summarised in Table 3.3. The key feedback included that stakeholders:

- want more information about AGN, including our role in the natural gas supply chain and the application of regulation to the business;
- are generally satisfied with our customer service and reliability levels;
- are generally supportive of initiatives that maintain and/or improve service; and
- believe that AGN has a role to play in assisting vulnerable customers.

[18] Deloitte 2015, *"Australian Gas Networks Stakeholder Insights Report"*, February 2015, pg. 10. Provided as Attachment 3.9 to this AAI.

TABLE 3.3: STAKEHOLDER INSIGHTS

Insight	Summary
Customers don't understand AGN's role in the industry and the regulatory model.	Community needs and expectations with respect to information are changing. Customers want more information about businesses to help them make informed decisions. In terms of our business, this specifically relates to the regulatory model (why and how AGN is regulated including how prices are set) and our operational activities, including where AGN fits in the natural gas supply chain.
Customers are concerned about rising energy costs and control over their bill.	Customers expressed concerns about future energy supply and rising costs. Price and the ability to control demand is the primary concern; however, customers also consider the environmental costs and value energy efficiency.
Customers view gas as a reliable source of energy.	Overall, customers like gas and believe it is a reliable and efficient energy source. They also recognise the importance of providing a safe supply.
Customers consider the local economy when evaluating alternatives.	Customers are looking for assurances that proposed initiatives will support local jobs and business or that AGN has at least considered this issue. They support initiatives that provide wider community benefits.
Customers are generally satisfied with AGN's service and response times.	Customers are generally satisfied with our current call centre response times but want to ensure that serious leaks are responded to as a priority.
Customers want more communication from AGN via multiple channels.	Customers want more communication timeliness and convenience. They value personalised messages and reminders about issues affecting them via 'real-time' digital channels. But when it comes to complex issues and/or planned service requirements, customers prefer to be informed through more direct means such as via the call centre, letter or email.
Customers support the concept of a Guaranteed Service Level (GSL) scheme that compensates gas-dependent customers who receive service below agreed 'standards'.	Customers think compensation for significant inconvenience and/or financial loss is a good idea. If a scheme were to be implemented, customers suggested a separate scheme or higher compensation amounts for business.
Customers value initiatives that improve community safety across the network.	Customers support investment in certain network safety initiatives, including those that reduce or minimise the incidence of gas leaks. Customers also support coordinating capital works with other infrastructure businesses.
Customers are less supportive of initiatives affecting individuals when network assets are within their control.	Customers generally support investment in safety initiatives but they also consider that consumers have a responsibility to ensure the safety of network assets on their property, and as such, they require more information about the benefits to the wider community if assistance is to be given to specific customers.
Customers support expanding and improving the network where there is a clear benefit to residents and business.	Customers support investment in costing network expansion and forecasting demand to achieve the goal of connecting more users to the network to provide a cost benefit for all customers.
Customers are more concerned with the overall price of gas than the tariff structure.	Customers care about the bottom line – their total gas bill – more than how we set prices and recover our costs.
Customers believe everyone should pay the same regardless of where they are on the network.	Customers favour network expansion and a standard price for all customers to make the network more accessible.
Customers believe AGN has a role to play in helping vulnerable customers.	Customers want us to work with consumer advocacy groups and other organisations in the supply chain to understand the issues facing vulnerable customers and to participate in the development and implementation of an appropriate response.
Customers trust that AGN is meeting its environmental obligations.	Whilst customers and stakeholders expect that AGN is meeting its environmental obligations, they think that we should be more transparent about what we do.

3.7 Implementation Phase

The objective of the Implementation Phase was to incorporate the feedback received during the Research Phase into our AA Proposal and business plans more generally. This phase involved further engagement with our Reference Groups and other key stakeholders as well as a high degree of internal engagement.

The key outputs from this phase were our submission to the ESCOSA review into the service standards to apply over the next AA period, the AGN *Insights and Implementation Report* and our AA Proposal.

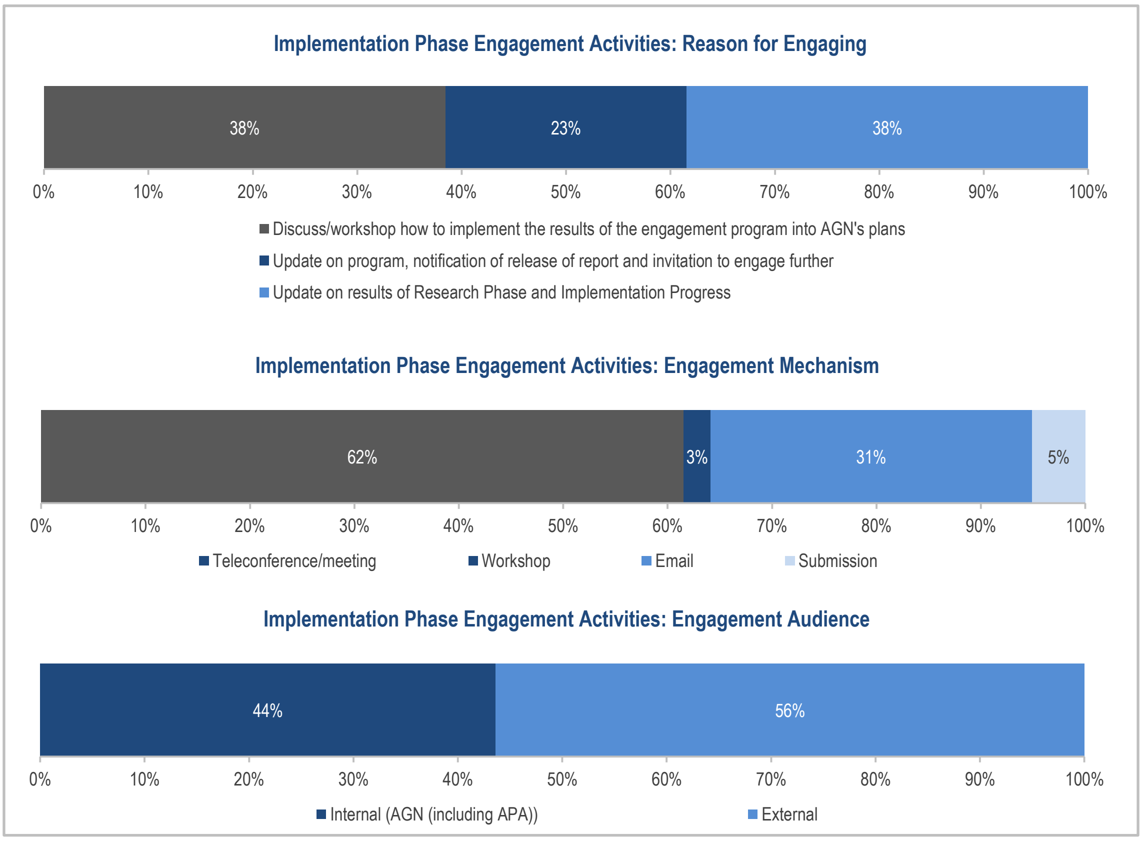
3.7.1 Engagement During the Implementation Phase

In contrast to the Strategy and Research Phases, there was a significant focus on internal engagement during the Implementation Phase. This reflected the need for the business to have a full and complete understanding of the feedback from the Research Phase and to disseminate that feedback throughout the business. A key step in this process was a series of workshops held between AGN and APA to discuss how to incorporate the stakeholder feedback into our AA Proposal (see Section 3.7.4).

The external engagement during this phase was focused on discussing with stakeholders how AGN intended to reflect the stakeholder insights into our AA Proposal. In total there were close to 40 instances of engagement during this Phase. This engagement included meetings with:

- *ESCOSA* – to discuss how the stakeholder feedback impacted the setting of service standards for the next AA period (see Section 3.7.2);
- *AGN Reference Group* – one meeting for Deloitte to present its stakeholder insights, and a second meeting with representatives from the AGN Board and AGN Executive Management Team to discuss how the business intended to incorporate the stakeholder feedback into its AA Proposal and to facilitate an open discussion with the AGN Reference Group; and
- *Retailer Reference Group* – similar to above, Deloitte presented the stakeholder insights to the Retailer Reference Group.

FIGURE 3.7: STAKEHOLDER ENGAGEMENT, IMPLEMENTATION PHASE



Note: Totals may not add due to rounding.

3.7.2 ESCOSA Jurisdictional Service Standards

As noted earlier, ESCOSA is responsible for setting the service standards that AGN must provide over the next AA period. ESCOSA commenced its review of service standards with the release of an Issues Paper on 7 March 2014. Following our submission to the Issues Paper, ESCOSA decided to delay its decision so that feedback from our stakeholder engagement program could be considered in setting service standards. In doing so, ESCOSA requested that AGN seek feedback on whether stakeholders valued:

- changes to our responsiveness to natural gas leaks;
- changes to our call centre responsiveness, and
- the introduction of a scheme to compensate those customers that receive service below agreed thresholds (commonly referred to as a Guaranteed Service Level (GSL) Scheme).

AGN provided a further submission to ESCOSA that considered the feedback from our stakeholder engagement program on 16 January 2015 (see Attachment 3.10). In short, and consistent with the Deloitte Stakeholder Insights Report, this submission stated that:

- stakeholders were not willing to pay for improvements in our call centre responsiveness (nor were they willing to pay less for reductions in our performance);
- while there was support to increase our responsiveness to gas leaks, AGN considered that the key stakeholder feedback related to improving the transparency around our actions to ensure a safe and reliable supply of natural gas; and
- although there was support for a GSL Scheme, AGN noted that there was not currently sufficiently reliable information on which to base such a scheme and that further stakeholder engagement on this issue was required (see Chapter 12 for further information on this matter).

ESCOSA noted in its Draft Decision, which is provided at Attachment 3.10, that:

> *"This review has not identified any areas of Australian Gas Networks' (AGN) service that require improvement through the introduction of service standards with performance targets…*
>
> *… [However] additional transparency around AGN's performance is required.*
>
> *An enhanced public reporting framework will provide greater assurance to the South Australian community that AGN is managing its network appropriately. It will also provide the necessary data to monitor any material deteriorations in the current service levels that may require service standards with performance targets in the future."* [19]

AGN was supportive of this position in its submission to the ESCOSA Draft Decision (see Attachment 3.10). AGN noted in its submission that the Draft Decision was consistent with both stakeholder feedback and AGN's intention to increase the public reporting of business performance through our Vision Statement:

> *"The Draft Decision recognises that AGN's current service levels are already at a high level, and as a result, it is not necessary to introduce any new performance targets for the business. Whilst no new targets have been proposed, ESCOSA is requesting that AGN increase its periodic reporting on key customer service and safety parameters.*

[19] ESCOSA 2015, "*Australian Gas Networks Jurisdictional Service Standards for the 2016-2021 Regulatory Period*", Draft Decision, March 2015, pg. 1. Provided as Attachment 3.10 to this AAI.

> *The Draft Decision is considered to be consistent with earlier submissions by AGN and also with the values of our stakeholders. More specifically, our stakeholder engagement program found that customers:*
>
> - *want more information from AGN across various channels; and*
> - *value initiatives that improve community safety.*
>
> *AGN is already responding to these stakeholder insights by redeveloping and implementing a Vision Statement which requires the setting and public reporting on our performance across several key aspects of customer service. This includes the time taken to respond to publicly reported gas leaks, our network reliability performance and the number of complaints received from the public. AGN intends to improve or maintain these aspects of service delivery and publicly report our progress over the upcoming regulatory period."* [20]

The Final Decision released by ESCOSA was consistent with the Draft Decision and our submission to that decision (see Attachment 3.10).

3.7.3 AGN Insights and Implementation Report

The AGN *Insights and Implementation Report* (hereafter the AGN Implementation Report) is one of the key inputs into the preparation of this AA Proposal (see Attachment 3.11). The AGN *Implementation Report* detailed how AGN intended to incorporate the feedback and insights from our stakeholder engagement program into our AA Proposal. More specifically, the report:

- explained our stakeholder engagement process;
- explained the Deloitte stakeholder insights
- grouped the stakeholder insights into four operational themes to assist the business integrate feedback into our AA Proposal (see Figure 3.8);
- explained in detail how AGN intends to incorporate the stakeholder feedback into our AA Proposal; and
- prompted feedback from stakeholders on all aspects of the above.

The AGN Implementation Report was open for public consultation for a four-week period. AGN published the report on our stakeholder engagement website and sent notifications of its release to key stakeholder groups (the AEMC, the South Australian Government, the OTR, AEMO, the AER and the CCP), our two Reference Groups and registered subscribers to our website. AGN also offered to take verbal submissions from key stakeholders.

Despite the above, AGN did not receive any submissions on its report, which may reflect one or more of the following:

- *resource constraints* – AGN was continually made aware of the resourcing pressures faced by key stakeholders, which were driven by the large number of energy market reviews under way during our consultation period (including for example the New South Wales, South Australian, Queensland and Australian Capital Territory electricity distribution and transmission regulatory reviews);
- *high reliability and customer service levels* – as per the outcomes of our engagement, stakeholders are generally satisfied with the performance of the Network; and

20 AGN 2015, "AGN Response to ESCOSA Draft Decision on Jurisdictional Service Standards", April 2015, pg. 2. Provided as Attachment 3.10 to this AAI.

- *the implementation of a robust Engagement Program* – AGN implemented a comprehensive engagement program, and as such, stakeholders did not feel further input was required.

FIGURE 3.8: AGN OPERATIONAL THEMES

Despite the lack of submissions, the development of the AGN Implementation Report was an important input into the development of this AA Proposal. This is because the Implementation Report required the business to consider at an early stage the implications of the stakeholder feedback on the initiatives explained in this AAI. AGN considers this to be a key step in ensuring that our AA Proposal promotes the long-term interests of consumers.

As there were no submissions received, the AA Proposal continues to be reflective of the initiatives outlined in the Implementation report.

3.7.4 Access Arrangement Proposal

As explained earlier, the primary objective of our engagement program is to ensure that our AA Proposal, by incorporating information on stakeholder values, better promotes the NGO. This section provides an overview of how AGN has incorporated the feedback received from our stakeholder engagement program throughout the AA Proposal. AGN believes that our proposal is reflective of the values of our stakeholders and is therefore in the long-term interests of consumers.

3.7.4.1 General Approach to Implementing Stakeholder Feedback

The initiatives included in our AA Proposal have a sound asset management/planning foundation. That is, all initiatives included in our AA Proposal reflect actions that AGN consider are required to ensure the ongoing safe and reliable supply of Reference Services. The stakeholder engagement program was primarily used to inform the scope and delivery of those initiatives.

Figure 3.9 shows the process used by AGN to develop the initiatives set out in this AAI, including how stakeholder engagement was used to inform those initiatives. This process is summarised as follows:

1. AGN undertook a detailed review of the initiatives required to ensure the ongoing safe and reliable operation of the Network. Some of the initiatives identified at this stage had related expenditure, whilst others were related to behaviour (for example, the way tariffs are structured) and had no associated financial cost.

2. As part of the process of developing our key asset management plans, all initiatives were reviewed by the senior management of AGN and APA. This process led to certain initiatives being excluded from further consideration (for example, Initiative 6 in Figure 3.9).

3. AGN engaged with stakeholders during the Strategy Phase to determine those initiatives that were suitable for stakeholder engagement, and consequently formed part of our engagement program.

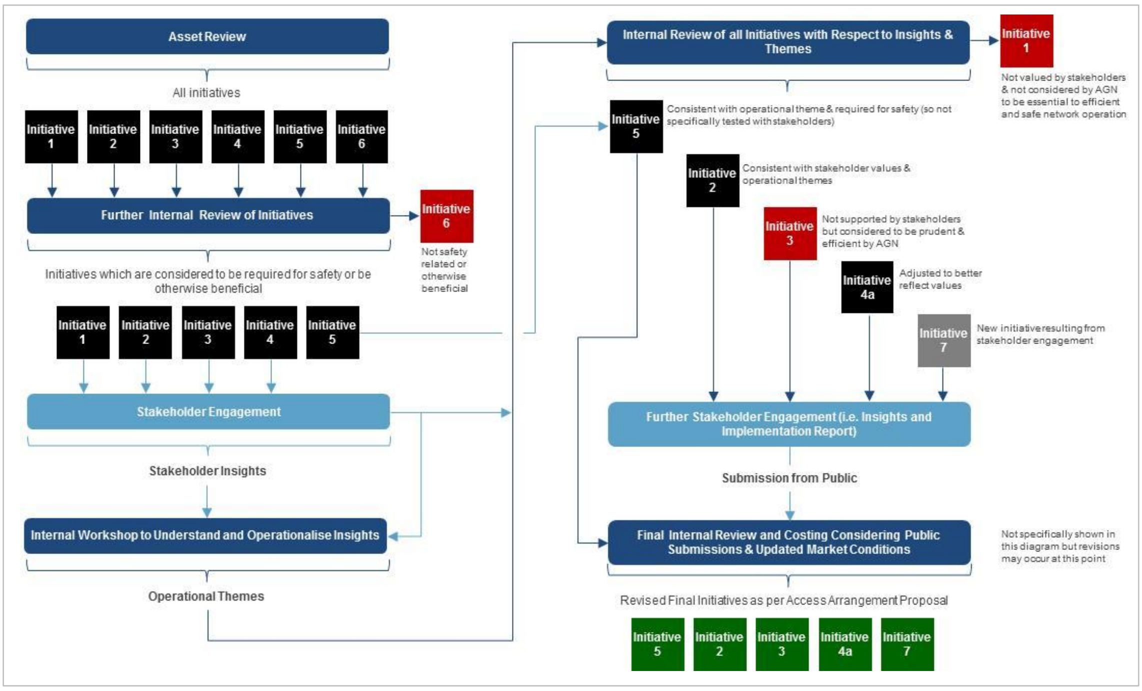
4. AGN engaged with stakeholders during the Research Phase to determine their willingness to pay for certain initiatives and to understand their values.

5. AGN and APA held a series of workshops to determine how the stakeholder feedback impacted our proposal, which led to excluding certain initiatives (Initiative 1 in Figure 3.9), incorporating the initiative as proposed (Initiative 2) or amending the initiative to better reflect stakeholder values (Initiative 4a). In limited cases, the stakeholder feedback resulted in new initiatives (Initiative 7).

6. AGN undertook further engagement on its revised initiatives through the AGN Implementation Report, which explained how AGN intends to reflect stakeholder feedback into its AA Proposal.

7. AGN then undertook further review of its business plans/initiatives as part of the process of finalising its AA Proposal.

FIGURE 3.9: IMPLEMENTATION OF STAKEHOLDER ENGAGEMENT RESULTS



3.7.4.2 Integration of Willingness-to-Pay Results

Table 3.4 summarises the specific willingness-to-pay results and how these results have been factored into our AA Proposal. AGN, in most cases, incorporated those initiatives that were supported by workshop participants (i.e. where 50% or more participants were willing to pay for an initiative). In certain other cases, AGN either removed or amended a proposed initiative in response to the willingness-to-pay results from the workshops.

TABLE 3.4: INCORPORATION OF WILLINGNESS-TO-PAY RESULTS

Initiative Tested	Workshop Support	Incorporated by AGN in this AA Proposal?
Would you be prepared to pay up to $1.50 per year more to increase average two-hour leak response rate to 98% of reported gas leaks?	✓ 61%	✗ **No.** While there was support for this initiative, AGN considered that stakeholders were primarily concerned with understanding how leak reports are managed by the business. As a result, AGN has committed to updating its website to include information on our Leakage Management Procedure and to report our performance in this area periodically on our website. AGN's decision to not change the response rate was supported by ESCOSA in its Draft Decision (DD).
Would you be prepared to pay up to $0.50 per year less to decrease average two-hour leak response rate to 90% of reported gas leaks?	✗ 0%	✗ **No.** Stakeholders strongly opposed initiatives that would lead to lower network safety. AGN's decision to not change our current targets was supported by ESCOSA in its DD.
Would you be prepared to pay $1 per year more to increase the average five-minute telephone response rate to 95% from 7am to 10pm?	✗ 37%	✗ **No.** As outlined in our submission to ESCOSA, stakeholders did not support this initiative and AGN did not consider that it would increase network safety or efficiency. AGN's decision to not implement was supported by ESCOSA in its DD.
Would you be prepared to pay up to $1 per year less on your gas bill to decrease the average five-minute response rate to 90%?	✗ 15%	✗ **No.** Stakeholders did not support this proposal and AGN considered it to be detrimental to our service standards and potential for network expansion. AGN's decision to not implement was supported by ESCOSA in its DD.
Would you be prepared to pay up to $0.50 per year more to implement a GSL scheme?	✓ 65%	✗ **No.** While there was support for this initiative, AGN noted in its submission to ESCOSA that there were practical limitations to introducing a GSL scheme. As explained in Chapter 12, AGN intends to undertake further stakeholder engagement during the next AA period to design incentives to improve customer service. AGN's position was supported by ESCOSA in its DD.
Would you be prepared to pay up to $0.50 per year more to replace identified instances of above ground poly pipe and old plastic fittings?	✓ 85%	✓ **Yes.** AGN considers that this initiative is required for the safe supply of natural gas. It also received directional support from a high proportion of workshop participants. This initiative is included as a Capital Expenditure (capex) Business Case (see Attachment 7.1).
Would you be prepared to pay up to $0.20 per year more to rectify sites that pose a safety risk (inlets inside cavities and inlets under buildings)?	✓ 87%	✓ **Yes.** AGN considers that this initiative is required for the safe supply of natural gas. It also received directional support from a high proportion of workshop participants. This initiative is included in the Mains Replacement Plan (see Attachment 8.2).
Would you be prepared to pay up to $2 per year more to fit fire-shut off valves?	✓ 89%	✓ **Yes.** AGN considers that this initiative is required for the safe supply of natural gas. It also received directional support from a high proportion of workshop participants. This initiative is included as a capex Business Case (see Attachment 7.1).
Would you be prepared to pay up to $6 per year more for AGN to repair all customer outlet service leaks?	✓ 71%	✗ **No.** AGN notes that this initiative received strong support from stakeholders, however, offering this service as a regulated activity is problematic as it involves working on non-AGN owned assets. As such, we are currently considering the best way to deliver the service to customers. It may be that we look to offer this service as an unregulated activity. AGN intends to liaise with the AER on this matter prior to the release of the AER Draft Decision.
Would you be prepared to pay up to $1.50 per year more for AGN to increase its mains replacement program to 220 kilometres per year?	✓ 56%	✓ **Yes.** AGN considers mains replacement to be an important aspect of network safety. This provides directional support for AGN to complete its mains replacement program as soon as is practicable. See Mains Replacement Plan (Attachment 8.2).

TABLE 3.4: INCORPORATION OF WILLINGNESS-TO-PAY RESULTS – CONTINUED.

Initiative Tested	Workshop Support	Incorporated by AGN in this AA Proposal?
Would you be prepared to pay up to $0.50 per year more on your gas bill to improve the coordination of capital works?	✓ 83%	**Variation is included**. AGN considers this to be an important initiative, but considers that it can be delivered with existing resources, and as such, is not seeking additional funding over the next AA period.
Would you be prepared to pay up to $0.50 per year more for AGN to relocate customers' gas meters exposed to the risk of damage?	✓ 52%	✓ **Yes.** AGN considers that this initiative will improve network safety and increase our service to customers. This initiative received marginal support from the workshop participants. This initiative is included as a capex Business Case (see Attachment 7.1).
Would you be prepared to pay up to $3 per year more for AGN to install remote meter reading devices?	✗ 44%	**Variation is included**. Stakeholders told us that they were not willing to pay for remote meter reading devices to be rolled out to all new and replacement meters as well as to troublesome meters. In reviewing the initiative in light of stakeholder feedback, AGN has moderated its proposal to include a pilot program to those meters that are difficult to access and has included the anticipated benefits of this project, to offset its total cost (see Business Case, Attachment 7.1).
Would you be prepared to pay up to $0.50 per year more for AGN to explore network expansion?	✓ 56%	✓ **Yes.** AGN considers that it is in the best interests of our customers to investigate potential network expansion opportunities. This initiative received marginal support from stakeholders. While no expenditure is included as a direct result of this feedback, AGN notes the support for network expansion opportunities, such as that presented in opex Business Case (see Attachment 7.1).

3.7.4.3 Integration of Other Stakeholder Feedback

AGN received a range of additional feedback during its stakeholder engagement program, primarily through the discussion with and between workshop participants and our dedicated stakeholder meetings. This feedback included that:

- stakeholders want more information from AGN, including about the natural gas supply chain, the regulatory model, the drivers and composition of their natural gas retail bill, our environmental commitments, technical fact sheets (for example, meter location specifications) and assistance in communicating with their members (for example, assistance in developing fact sheets for non-English speaking residents);
- stakeholders increasingly want to access information through digital channels, particularly where this impacts on their natural gas supply (such as through SMS, email or the website for unplanned interruptions);
- stakeholders value increased transparency over our operations, including how we manage network safety and reporting on our customer service standards and regulatory (including environmental) obligations;
- stakeholders are more concerned about their overall natural gas bill rather than the structure of the prices (or tariffs) that they pay; and
- while stakeholders considered we have a role to play in assisting vulnerable customers, they also told us we should work alongside existing organisations that represent these customers rather than to operate independently.

Our AA Proposal has also had significant regard to the specific feedback from our Retailer Reference Group in regard to the terms and conditions governing access to the Network (see Chapter 17) and our tariff structures (see Chapter 15).

Stakeholder feedback has been considered and incorporated throughout this AAI.

3.8 Ongoing Engagement Phase

The objective of the Ongoing Engagement Phase is to evaluate the effectiveness of previous engagement activities and to incorporate learnings into future programs and to continually engage with the stakeholders that are impacted by our business.

3.8.1 Feedback on the Stakeholder Engagement Program

Tracking and transparently reporting on the performance of our stakeholder engagement program is an important part of our strategy.

The KPIs relating to our stakeholder engagement program were developed during the Strategy Phase having regard to the principles set out in the AER Consumer Engagement Guideline. The specific KPIs for the South Australian engagement program are set out in the South Australian Engagement Strategy (see Attachment 3.6). Some of the specific feedback received from our Reference Group members and workshop participants is set out in Box 3.1.

TABLE 3.5: AGN'S STAKEHOLDER ENGAGEMENT PERFORMANCE

AER Principle	Measurement and Target	AGN Performance
Clear, accurate and timely communication	• Stakeholder satisfaction with: ○ educational materials used during customer workshops and in surveys and interviews; and ○ the process for engagement (how clearly materials were presented). • As measured by a 70% or above satisfaction score on the workshop as a whole.	✓ 97% of workshop participants (n=59) agreed or strongly agreed that the workshop met their expectations.
Accessible and inclusive engagement	• Endorsement from Reference Groups that engagement reaches a representative group of the target population, as measured through a feedback survey on the process. • Stakeholder satisfaction, as measured by 70% or above score, on the following workshop feedback survey elements: workshop pace, education materials and collaboration within the workshop.	• Of the Reference Groups: ✓ 100% (n=3) of the AGN Reference Group ad 100% of the Retailer Reference Group (n=1) were satisfied that the targeted audience was reached through our engagement program. ? Whilst the feedback forms we received were positive, only 30% of the AGN Reference Group and 25% of the Retailer Reference Group completed the forms. This may be a function of the time poor nature of members and or a desire from members to hold back feedback until seeing our final submission. This is an area of improvement for future programs. • Of the workshop participants: ✓ 78% (n=32) agreed that the timing and pace of the workshop was good or very good. Others commented that a little more time was needed. This is a key learning for AGN to consider as part of future workshops. ✓ 96% (n=56) indicated they valued the education materials provided. ✓ 98% (n=59) agreed or strongly agreed that they enjoyed the collaboration of the workshop.
Transparent process	• Public disclosure of details about engagement activities. Publish on website: strategy, workshop materials, stakeholder insights, business plan and KPI tracking. • Attendance by Chief Executive Officer (CEO) at one or more workshop. • Publish AGN Implementation Report outlining application of stakeholder insights. • Access to Board and Management team to AGN Reference Group.	✓ We have developed a dedicated stakeholder engagement website on which key documents have been published (www.stakehodlers.agnl.com.au). ✓ AGN CEO attended a workshop. ✓ In February 2015, AGN published its Implementation Report on the stakeholder engagement website and promoted its release. ✓ Senior management attended all AGN Reference Group meetings. Further, in March 2015, AGN's Board and Management team met with the AGN Reference Group.

Box 3.1: Stakeholder Feedback

"We appreciate your level of resourcing and you have done a good job liaising with stakeholders and making yourselves accessible."

AGN Reference Group Member

"I commend and thank the AGN Regulatory team for all their time, thought and effort into this Stakeholder engagement program. Also your friendliness, openness and willingness to listen."

AGN Reference Group Member

"Congratulations to AGN for being proactive and being willing to listen. A sound approach has been developed and implemented."

AGN Reference Group Member

"It's positive that AGN is concerned with our opinions."

South Australian Regional Workshop Participant

3.8.2 Ongoing Engagement

AGN needs to ensure that it continually engages with stakeholders to ensure that we provide services in a manner that promotes the long-term interests of consumers. AGN intends to do this in a number of ways, including through improving the information that is available (or easily accessible) to stakeholders (as described in Section 3.7.4.3), to conduct regular stakeholder workshops and to continually engage with our Reference Groups.

As noted earlier, the nature of this engagement will continue to be informed by our stakeholders, and as such, will evolve over time.

3.9 Summary

AGN has implemented a robust stakeholder engagement program to inform the initiatives set out in our AA Proposal, which primarily reflects that:

- the engagement strategy was informed by considerable stakeholder feedback, including in regard to identifying who AGN should engage with, the appropriate form of engagement for each stakeholder group and the topics that should form part of our stakeholder engagement program;
- our stakeholder engagement program was supported by the AGN Board and the executive management teams of both AGN and APA;
- our stakeholder engagement program was supported by appropriate educational materials, including (and as recommended by the AGN Reference Group) information on the natural gas supply chain, application of regulation to our business and expectations of future changes in retail natural gas bills (to form a base for our willingness-to-pay research);
- we engaged with a broad and representative sample of key stakeholders, which was greatly facilitated by the establishment of the AGN Reference Group, Retailer Reference Group, workshops and dedicated interviews;
- stakeholder feedback was independently captured and reported on by an independent advisor (Deloitte);
- stakeholder feedback was received and transparently reported on by AGN and is intended to be reflected in our AA Proposal, including through the AGN *Implementation Report*; and that

- feedback on our performance was captured so we can improve the delivery of our stakeholder engagement program over time.

AGN is confident that our AA Proposal has been appropriately informed by our stakeholder engagement program, and as such, that the initiatives set out in the remainder of this AAI promote the long-term interests of consumers.

4 Past Performance

Page intentionally left blank

4 Past Performance

4.1 Introduction

This chapter discusses the key outputs delivered by Australian Gas Networks Limited (AGN) over the current (2011/12 to 2015/16) Access Arrangement (AA) period, including our safety performance, customer service and our productivity performance over the past 16-year period. With regard to the latter, this includes a discussion of the rate of change in productivity and our absolute (or overall) productivity levels relative to other gas distributors operating in Australia.

Furthermore, the National Gas Rules (NGR) sets out the specific requirements that an Access Arrangement Information (AAI) must contain. This chapter provides this information as it relates to the operating expenditure (opex), capital expenditure (capex) and demand performance of AGN relative to the benchmarks set by the Australian Energy Regulator (AER) over the current AA period.

4.2 Requirements of the National Gas Rules

Rule 72(1)(a) of the NGR provides that a full AA must provide capex, opex and demand information for the current AA period. Rule 72(1)(a) states:

> *"(1) The access arrangement information for a full access arrangement proposal (other than an access arrangement variation proposal) must include the following:*
>
> *(a) if the access arrangement period commences at the end of an earlier access arrangement period:*
>
> *(i) capital expenditure (by asset class) over the earlier access arrangement period; and*
>
> *(ii) operating expenditure (by category) over the earlier access arrangement period; and*
>
> *(iii) usage of the pipeline over the earlier access arrangement period showing:*
>
> *(A) for a distribution pipeline, minimum, maximum and average demand and, for a transmission pipeline, minimum, maximum and average demand for each receipt or delivery point; and*
>
> *(B) for a distribution pipeline, customer numbers in total and by tariff class and, for a transmission pipeline, user numbers for each receipt or delivery point."*

4.3 Data

The information provided in this chapter, and in this AAI more generally, is based on the annual Regulatory Information Notices (RINs) submitted to the AER for the 2011/12 to 2013/14 period as well as the best available actual/forecast information for 2014/15 and 2015/16. Given the timing of preparation of this AAI it was not possible to include actual information for 2014/15 and 2015/16.

The data for 2014/15 are based on nine months of actual and three months of forecast information, while the data for 2015/16 are based on the best available forecast information. The 2014/15 data will be updated in response to the AER Draft Decision using actual information. At that time AGN will also update the 2015/16 data using the most recent forecast information available to the business.

For ease of reference, the AAI in some cases refers to 2014/15 and 2015/16 data as 'actual' data/information. All financial data set out in this AAI, unless stated otherwise, are expressed in constant 2014/15 dollar terms (otherwise referred to as 'real' and/or '$2014/15'). This is so the impact of inflation is removed when comparing changes in financial data from one year to another.

4.4 Network Performance

AGN's vision is to be the leading natural gas distributor in Australia. This includes delivering top quartile levels of customer service, being a good employer and operating our network in a sustainably cost-efficient manner. These matters are summarised in this chapter and discussed in more detail in Chapter 2 of this AAI.

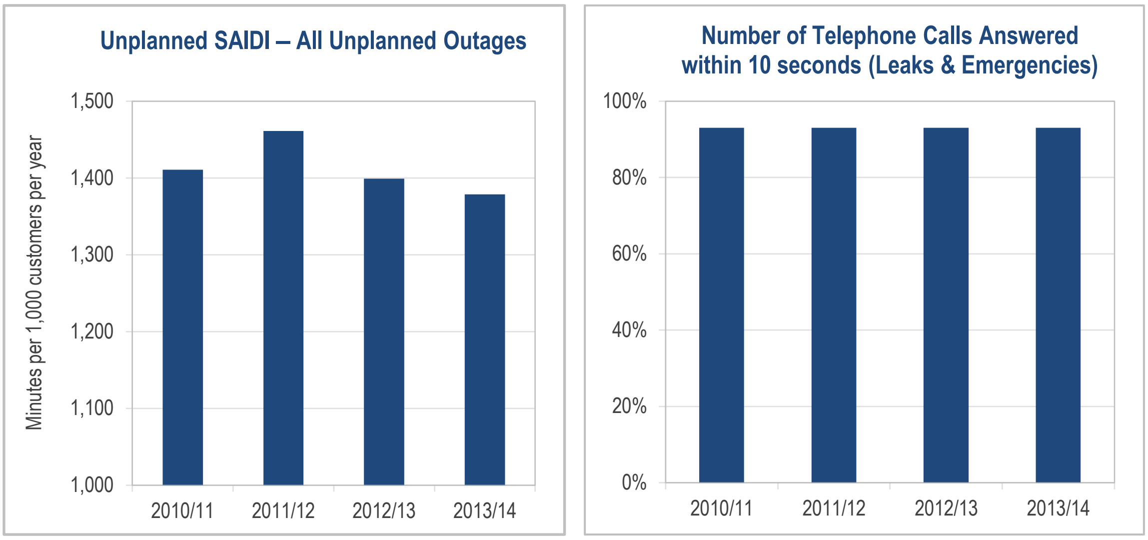
4.4.1 Delivering for Customers

The provision of a safe and reliable supply of natural gas is the most important driver of business performance. As natural gas is a fuel of choice, AGN is also focused on providing high levels of network reliability and customer service. AGN has delivered high levels of network reliability and customer service within the opex and capex benchmarks set by the AER for the current AA period. In summary, in respect of:

- *safety* – AGN complied with the safety requirements set out in our Leakage Management Procedure, which sets the timeframe for the repair of publicly reported gas leaks (the time to repair a leak depends on the severity or risk associated with that leak) and for undertaking routine surveys of mains to check for leaks;
- *reliability* – there has been, on average, only 15 major network interruptions per year (a 'major' interruption is one that affects five or more customers and was attributable to our actions, asset condition or third party damage); and
- *customer service* – over 90% of customer calls to our emergency call centre are answered within 10 seconds.

AGN's strong network reliability and customer service performance is shown in Figure 4.1. The System Average Interruption Duration Index (SAIDI), which measures average minutes lost per 1,000 customers, has been declining over the past four years. Our SAIDI performance is consistent with good industry practice. The number of telephone calls relating to leaks and emergencies responded to within 10 seconds has been maintained at high levels.

FIGURE 4.1: AGN'S RELIABILITY AND CUSTOMER SERVICE PERFORMANCE IN SOUTH AUSTRALIA



Note: The System Average Interruption Duration Index (SAIDI) is calculated as (Total customer hours interrupted multiplied by 60) divided by (Total number of customers per 1,000) and in Figure 4.1 includes all unplanned outages.

AGN intends to (at least) maintain the high levels of customer safety, reliability and service over the next (2016/17 to 2020/21) AA period. This is consistent with the feedback from our stakeholders that they were generally supportive of our current service levels (our stakeholder engagement program is discussed in Chapter 3 of this AAI).

4.4.2 A Good Employer

As described in Chapter 2, AGN has achieved industry best practice employee safety levels over the current AA period. Employee safety is typically measured by the lost-time injury frequency rate (LTIFR), which is the number of lost-time injuries (defined as an occurrence that resulted in a fatality, permanent disability or time lost from one day shift or more) over a year relative to the total number of hours worked (usually per million hours worked) in that year. In 2013/14, there were 1.3 lost time injuries per million hours worked.

In addition, we are aiming to design and undertake an employee engagement survey from 2015/16 onwards.

4.4.3 Sustainably Cost Efficient

AGN has engaged Economic Insights to undertake an analysis of our past productivity performance. This analysis is set out in the following two reports:

- *The Productivity Performance of Australian Gas Networks' South Australian Gas Distribution System*, which is referred to as the Productivity Report and is provided as Attachment 4.1 to this AAI; and

- *Benchmarking Australian Gas Networks' South Australian Business Operating and Capital Costs using Partial Performance Indicators*, which is referred to as the Partial Indicator Report and is provided as Attachment 4.2 to this AAI.

This section reports the key findings of the above two reports.

4.4.3.1 Productivity Report

The Productivity Report analyses the following two key measures of productivity:

- *Total Factor Productivity (TFP)* – which measures the rate of change in the ratio of total output relative to all inputs used; and

- *Multilateral TFP (MTFP)* – which measures the absolute (or overall) productivity levels of different businesses.

In developing the Productivity Report, Economic Insights has measured TFP across three outputs (throughput, customer numbers and system capacity) and eight inputs (opex, length of transmission pipelines, high pressure pipelines, medium pressure pipelines, low pressure pipelines and services, meters and other capital).

The analysis compared the productivity performance of AGN's South Australian business (referred to as AGN SA in the Productivity Report and the Partial Indicator Report) with the three Victorian gas distributors (AGN Victoria (AGN Vic), Ausnet Services and MultiNet), Jemena Gas Networks (JGN) in New South Wales and AGN's Queensland (AGN Qld) gas distribution business. The comparative analysis was undertaken for the 1999 to 2014 period, which reflects the period for which data were available for the businesses included in the sample.

With regard to TFP, Economic Insights found that AGN's South Australian natural gas distribution network (the Network) had an annual average TFP growth rate of 0.9% over the period, which is consistent with the TFP growth rate of 1.0% achieved by JGN over a similar period. Economic Insights concluded that:

> *"AGN SA's changes in output and input quantities have led to a robust productivity performance over the past 15 years, averaging 0.9 per cent annually, driven largely by significant reductions in opex."* [21]

The MTFP results are shown in Figure 4.2 (which has been taken from Figure 4.1 in the Economic Insights Productivity Report). The results are presented relative to AGN's Victorian network having a value of one, being the network with the highest productivity of all gas distribution businesses included in the sample. Economic Insights noted that our MTFP performance was favourable given the relatively adverse operating conditions of the Network relative to the other distributors included in the sample:

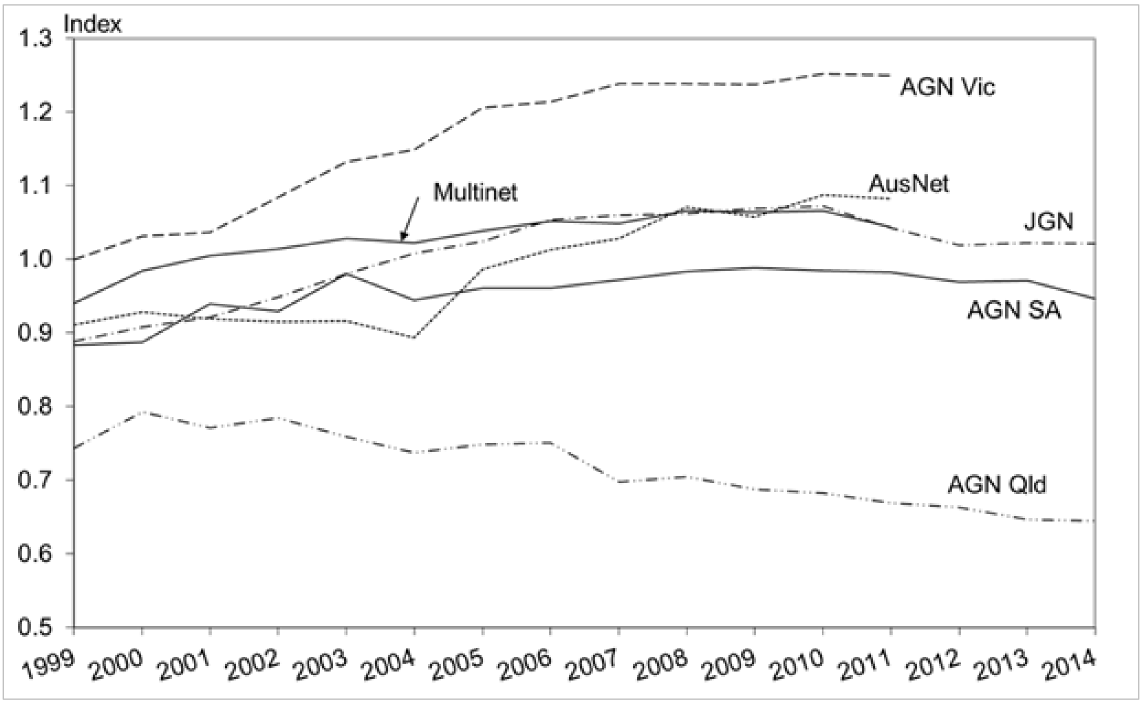
> *"The MTFP results indicate that AGN SA is close to JGN's and Multinet's productivity levels… For example in 2011, which is the latest year for which Multinet data is available, there was approximately a 7 per cent difference between the productivity levels of AGN SA and these two businesses. There has also been reasonable comparability with AusNet over most of the sample period. On the other hand, AGN Victoria had a higher level of productivity than the other comparator GDBs [Gas Distribution Businesses], and AGN Qld a lower level of productivity.*
>
> *This comparison is favourable for AGN SA given that the operating environment conditions differ between GDBs. The three Victorian GDBs have higher domestic customer density and energy density per kilometre of main when compared to JGN and AGN SA. Furthermore, AGN SA is relatively small compared to JGN and the three Victorian GDBs. In terms of throughput it is less than half the size of each of the three Victorian GDBs and just over a quarter of the size of JGN and in terms of customer numbers is around two thirds the size of the Victorian GDBs and less than 40 per cent the size of JGN.*
>
> *The MTFP comparisons do not control for differences in scale or fully adjust for different operating environment conditions. While its scale and operating environment conditions could be expected to place AGN SA at a disadvantage in comparisons of productivity levels, it performs relatively well by almost matching the performance of some of the larger included GBDs. Taking the differences in network density and size into account, the results of this study indicate that AGN SA is most likely to be an efficient performer."* [22]

---

21 Economic Insights 2015, "*The Productivity Performance of Australian Gas Networks' South Australian Gas Distribution System*", May 2015, pg. 26. Provided as Attachment 4.1 to this AAI.

22 Economic Insights 2015, "*The Productivity Performance of Australian Gas Networks' South Australian Gas Distribution System*", May 2015, pg. ii-iii. Provided as Attachment 4.1 to this AAI.

FIGURE 4.2: AUSTRALIAN GDB MULTILATERAL TFP INDEXES, 1999-2014



Source: Economic Insights Productivity Report, May 2015.

Note: Years in Figure 4.2 are year-end 30 June for JGN, AGN SA and AGN QLD but are year-end 31 December for the Victorian networks.

Overall, Economic Insights found that:

> *"While its scale and operating environment conditions could be expected to place AGN SA at a disadvantage in comparisons of productivity levels, it performs relatively well by almost matching the performance of some of the larger included GDBs. Taking the differences in network density and size into account, the results of this study indicate that AGN SA is most likely to be an efficient performer."*[23]

AGN notes that each of the GDBs has achieved moderate productivity growth in the recent period relative to earlier years. As Economic Insights states:

> *"As all firms become efficient (eg in response to incentive regulation) then productivity growth rates will converge to the long run rate of technological change in the industry."*[24]

Future efficiency gains are therefore anticipated to be restricted to the rate of technological change in the gas distribution sector. The implications of this 'convergence' effect on the long-run rate of technological change are discussed in greater detail in Chapter 12.

4.4.3.2 Partial Indicator Report

The Economic Insights Partial Indicator Report presents the following partial performance indicators, which are analogous to those published by the AER for electricity distribution businesses:[25]

23 Economic Insights 2015, "*The Productivity Performance of Australian Gas Networks' South Australian Gas Distribution System*", May 2015, pg. iii. Provided as Attachment 4.1 to this AAI.

24 Economic Insights 2012, "*The Total Factor Productivity Performance of Victoria's Gas Distribution Industry*", 26 March 2012, pg. 7.

25 AER 2014, "*Electricity Distribution Network Service Providers Annual Benchmarking Report*", November 2014.

- opex per customer relative to customer density (where customer density is total customers per kilometre of mains);
- asset cost per customer relative to customer density; and
- total cost per customer relative to customer density.

The key finding of Economic Insights in its Partial Indicator Report is as follows:

> *"AGN SA is a mid-sized GDB that does not enjoy, to the same degree, the economies of scale attained by JGN, the Victorian GDBs and ATCO WA [Western Australia]. For this reason, it should not be expected to outperform larger utilities. It also has an especially low energy density per customer. Nevertheless, comparisons of total cost per customer suggest that AGN SA's cost per customer is closely comparable to its peers, such as the three Victorian GDBs and JGN, which all have comparatively high customer density."*[26]

4.4.3.3 Summary of Findings

Overall, Economic Insights finds that the productivity performance of AGN is comparable to the other businesses included in the sample despite the Network having significantly lower scale and operating environment conditions.

4.5 Operating Expenditure

This section addresses the requirement of Rule 72(1)(a)(ii) of the NGR for the AAI to include "*operating expenditure (by category) over the earlier access arrangement period*". This section compares actual and benchmark opex over the current AA period.

4.5.1 Actual and Benchmark Operating Expenditure

Tables 4.1 and 4.2 show actual and benchmark opex by category for the current AA period. AGN's actual opex is expected to be $335 million over the current AA period (excluding debt raising costs), which is approximately $32 million (or 9%) below the benchmark of $367 million. This positive outcome reflects several factors, including:

- the strict cost management practices applied across the business in response to the AER Efficiency Benefit Sharing Scheme (EBSS), which is discussed in more detail in Chapter 11 of this AAI; and
- the significant scale of our contractor the APA Group, which is the largest owner/operator of natural gas infrastructure in Australia (as explained in Chapter 2, the APA Group provides AGN with operating, maintenance and construction services).

[26] Economic Insights 2015, "*Benchmarking Australian Gas Networks' South Australian Business Operating and Capital Costs Using Partial Performance Indicators*", May 2015, pg. iv. Provided as Attachment 4.2 to this AAI.

TABLE 4.1: AGN ACTUAL OPEX FOR THE CURRENT AA PERIOD

$2014/15 million	2011/12 actual	2012/13 actual	2013/14 actual	2014/15 forecast	2015/16 forecast	Total
Operating and Maintenance	41.7	41.0	43.5	42.4	42.9	**211.4**
Administration and General	8.4	8.4	8.5	8.2	8.2	**41.6**
Unaccounted for Gas	11.3	11.6	10.9	8.8	9.4	**51.9**
Network Development	6.0	5.1	5.6	6.6	6.6	**30.0**
Total	**67.4**	**66.1**	**68.5**	**65.9**	**67.1**	**335.0**
Debt Raising Costs	0.8	0.8	0.8	0.8	0.8	**4.0**
Total Actual / Forecast Operating Expenditure	**68.2**	**66.9**	**69.3**	**66.7**	**67.9**	**339.0**

Note: Totals may not add due to rounding.

TABLE 4.2: AER BENCHMARK OPEX FOR THE CURRENT AA PERIOD

$2014/15 million	2011/12	2012/13	2013/14	2014/15	2015/16	Total
Operating and Maintenance	44.5	45.2	45.8	45.7	45.4	**226.6**
Administration and General	9.0	8.7	8.6	8.5	8.4	**43.3**
Unaccounted for Gas	14.3	13.3	11.7	10.0	8.1	**57.4**
Network Development	8.2	7.6	7.8	8.1	7.8	**39.4**
Total	**76.0**	**74.8**	**74.0**	**72.3**	**69.6**	**366.7**
Debt Raising Costs	0.7	0.7	0.8	0.8	0.8	**3.7**
Total Benchmark Operating Expenditure	**76.6**	**75.5**	**74.7**	**73.1**	**70.4**	**370.3**

Note: Totals may not add due to rounding.

4.5.2 Variations from Regulatory Benchmarks

Table 4.3 outlines the key variances between actual and benchmark opex by category over the current AA period. The explanation of the material variations (greater than 5%)[27] between actual and benchmark opex are as follows:

- *operating and maintenance* – the outperformance relates to the ability of APA as the network operator to achieve efficiencies with respect to the unit cost of work delivered as well as the scope of work undertaken;

- *unaccounted for gas (UAFG)* – the key driver of the lower UAFG expenditure reflects the significant reductions in the volume of UAFG achieved over the current AA period. AGN estimates that actual UAFG volumes will be significantly below the benchmark UAFG volumes by the end of the current AA period; and

- *network development* – the lower network development expenditure reflects the lower appliance rebate payments, which in turn reflects the ongoing subdued levels of housing construction and renovation activity in South Australia over the current AA period (which, as explained in Section 4.6.1 and Chapter 14, has also led to lower demand for gas across the Network).

The difference in debt raising costs, while above the 5% materiality threshold, is immaterial (and as such, is not discussed in this section).

27 The annual South Australian RIN requires AGN to provide an explanation for any variation greater than 5% from the benchmark. AGN has utilised the same threshold in this AAI.

TABLE 4.3: ACTUAL AND BENCHMARK OPEX BY CATEGORY OVER THE CURRENT AA PERIOD

$2014/15 million	Total Opex over 2011/12 to 2015/16		Variance ($)	Variance (%)
	Actual/Forecast	Benchmark		
Operating and Maintenance	211.4	226.6	-15.2	**-7%**
Administration and General	41.6	43.3	-1.6	**-4%**
Unaccounted for Gas	51.9	57.4	-5.4	**-9%**
Network Development	30.0	39.4	-9.5	**-24%**
Total	**335.0**	**366.7**	**-31.7**	**-9%**
Debt Raising Costs	4.0	3.7	0.4	**10%**
Total Actual / Forecast Operating Expenditure	**339.0**	**370.3**	**-31.3**	**-8%**

Note: Totals may not add due to rounding.

4.6 Capital Expenditure

This section addresses the requirement of Rule 72(1)(a)(i) of the NGR for the AAI to include "*capital expenditure (by category) over the earlier access arrangement period*". This section compares actual and benchmark capex over the current AA period.

4.6.1 Actual and Benchmark Capital Expenditure

Tables 4.4 and 4.5 show actual and benchmark capex by category for the current AA period. AGN's actual capex is expected to be $482 million, which is approximately $68 million (or 12%) below the benchmark of $547 million that was set by the AER for the current AA period. As there is no incentive scheme in place for capex, the vast majority of this saving accrues to customers. The increasing actual capex profile relative to that approved by the AER reflects:

- the delay in the release of the AER Further Final Decision for the Envestra [AGN] South Australian gas distribution network until 7 July 2011; and
- the timing of the subsequent decision by the Australian Competition Tribunal (ACT) on the appeal application lodged by AGN (who were known as Envestra at that time), which decision was made on 11 January 2012 but did not come into effect until 10 February 2012.

The then Board of the business was not prepared to commit to the higher capex program until there was clarity over the financial parameters that were to apply over the current AA period, which clarity was provided following the ACT decision in January 2012 (i.e. mid way through the first year of the current AA period). Following this, the Board initiated plans to increase capex to their current levels.

TABLE 4.4: AGN ACTUAL CAPEX FOR THE CURRENT AA PERIOD

$2014/15 million	2011/12 actual	2012/13 actual	2013/14 actual	2014/15 forecast	2015/16 forecast	Total
Mains Replacement	26.5	40.0	49.3	54.3	77.6	**247.7**
Meter Replacement	2.4	2.6	3.9	4.1	4.0	**17.1**
Augmentation	6.2	16.7	5.6	3.4	11.6	**43.5**
Telemetry	0.3	0.2	0.4	0.3	0.6	**1.7**
Regulators and Valves	0.3	1.0	2.9	2.9	0.7	**7.8**
Information Technology	0.1	2.6	7.4	11.6	2.3	**24.0**
Growth Assets	22.3	21.2	27.7	21.8	25.6	**118.6**
Other Distribution System	1.8	0.9	3.5	2.7	1.9	**10.8**
Other Non-distribution System	0.0	0.8	0.7	3.4	2.5	**7.4**
Total	**59.8**	**86.0**	**101.3**	**104.6**	**126.8**	**478.6**

Note: Totals may not add due to rounding

TABLE 4.5: AER BENCHMARK CAPITAL EXPENDITURE FOR THE CURRENT AA PERIOD

$2014/15 million	2011/12	2012/13	2013/14	2014/15	2015/16	Total
Mains Replacement	21.5	53.4	53.7	53.9	53.5	**235.9**
Meter Replacement	3.2	3.4	4.7	5.6	5.9	**22.8**
Augmentation	15.6	6.0	1.4	6.1	0.1	**29.2**
Telemetry	0.4	0.4	0.8	0.4	0.4	**2.5**
Regulators and Valves	0.9	0.9	0.9	0.9	0.9	**4.4**
Information Technology	4.2	2.2	3.0	2.2	0.4	**12.1**
Growth Assets	50.4	33.9	31.7	30.8	33.5	**180.2**
Other Distribution System	11.1	12.3	9.5	9.6	9.5	**52.0**
Other Non-distribution System	2.8	1.4	1.4	1.0	1.0	**7.6**
Total	**110.1**	**113.9**	**107.1**	**110.6**	**105.3**	**546.9**

Note: Totals may not add due to rounding.

TABLE 4.6: PROPOSED CAPITAL EXPENDITURE FOR THE CURRENT AA PERIOD

$2014/15 million	2011/12	2012/13	2013/14	2014/15	2015/16	Total
Mains Replacement	23.9	62.0	65.1	67.9	71.1	**290.0**
Meter Replacement	3.4	3.8	5.2	6.2	6.5	**25.1**
Augmentation	18.6	7.3	1.7	7.4	0.1	**35.1**
Telemetry	0.4	0.4	0.9	0.4	0.4	**2.7**
Regulators and Valves	0.9	1.0	1.0	1.0	1.0	**4.9**
Information Technology	4.3	2.3	3.1	2.4	0.4	**12.6**
Growth Assets	54.9	37.9	36.5	36.6	41.6	**207.6**
Other Distribution System	12.2	13.6	10.9	11.3	11.6	**59.6**
Other Non-distribution System	3.0	1.6	1.6	1.0	1.1	**8.2**
Total	**121.7**	**129.9**	**125.9**	**134.3**	**134.0**	**645.7**

Note: Totals may not add due to rounding.

4.6.2 Material Variations in Capex

Table 4.7 outlines the key variances between actual and benchmark capex for each category over the current AA period. The majority of the variations in capex are driven by the availability of more recent asset management information as the AA period progresses (that is, as forecast expectations are replaced by actual expectations/information). The material variances in capex are explained as follows:

- *Mains Replacement* – the higher expenditure primarily reflects the need to commence the replacement of the high-density polyethylene (HDPE) network, which program was not anticipated at the time the benchmarks were set by the AER (see Chapters 2 and 8 for further discussion on our HDPE mains replacement program);

- *Meter Replacement* – the lower expenditure reflects lower volumes of domestic meters replaced than was anticipated at the time the benchmarks were set, reflecting an updated view of the required replacement program for various meter family types;

- *Augmentation* – the higher expenditure reflects the completion of additional augmentation projects to that included in the benchmarks, namely the augmentation projects in Tapley's Hill Road, Gawler, and Salisbury in response to the higher than anticipated localised network capacity requirements in those areas;

- *Telemetry* – the lower expenditure reflects the increased penetration of telemetry on industrial meters, which can reduce the need for telemetry on nearby parts of the network. It is also noted that the cost of the installation of telemetry on industrial meters is lower than the installation of such equipment on valves and regulator installations;

- *Regulators and Valves* – the higher expenditure reflects the adoption of a new national design standard requiring more expensive components and installation costs, which costs are partly offset by improved performance resulting from a larger operating range and lower ongoing maintenance. Other contributing factors include increased decommissioning costs of existing regulators and valves due to greater traffic management requirements and higher than expected instances of asbestos, necessitating specialist removal to ensure no asbestos remained on site;

- *Information Technology (IT)* – the main driver of the significantly higher expenditure is the development and implementation of our Enterprise Asset Management (EAM) system, which is a large and complex IT system that will provide AGN with a single integrated asset management system (the requirements/complexity of the new EAM was not anticipated at the time the benchmarks were set);

- *Growth Assets* – the ongoing weakness in housing construction has impacted on customer growth;

- *Other Distribution System* – this category included the costs of complying with new requirements for road works and reinstatement, which costs have instead been directly allocated to affected capital works (i.e. augmentation, growth and mains replacement) rather than recorded separately under this category; and

- *Other Non-Distribution System* – the lower expenditure is largely a result of the purchase of fewer field trucks and tippers.

TABLE 4.7: ACTUAL AND BENCHMARK CAPEX BY CATEGORY OVER THE CURRENT AA PERIOD

$2014/15 million	Total Capex over 2011/12 to 2015/16		Variance ($)	Variance (%)
	Actual	Benchmark		
Mains Replacement	247.7	235.9	11.8	**5%**
Meter Replacement	17.1	22.8	-5.7	**-25%**
Augmentation	43.5	29.2	14.3	**49%**
Telemetry	1.7	2.5	-0.8	**-32%**
Regulators and Valves	7.8	4.4	3.4	**77%**
Information Technology	24.0	12.1	11.9	**99%**
Growth Assets	118.6	180.2	-61.7	**-34%**
Other Distribution System	10.8	52.0	-41.3	**-79%**
Other Non-distribution System	7.4	7.6	-0.3	**-3%**
Total	**478.6**	**546.9**	**-68.4**	**-12%**

Note: Totals may not add due to rounding.

4.7 Demand

This section addresses the requirement of Rule 72(1)(a)(iii) of the NGR for the AAI to include "*usage of the pipeline over the earlier access arrangement period*". This section compares actual and benchmark demand for our volume customers, who include residential and commercial customers that consume less than 10 terajoules per year. These customers account for around 90% of our total revenue.

4.7.1 Residential Customers

Table 4.8 compares actual and benchmark volumes for our residential customers. This table shows that the total volume of gas distributed to residential customers was below benchmark levels for all years of the current AA period aside from in 2012/13. As discussed in Chapters 2 and 14 of this AAI, 2012/13 is the only time over the past 16 years that AGN has achieved the benchmark volumes that have been set by the regulator. This is a key issue for AGN in this AA review process.

Overall, the total volume of natural gas supplied to residential customers is expected to be 5% below benchmark volumes over the current AA period.

TABLE 4.8: ACTUAL VERSUS BENCHMARK RESIDENTIAL VOLUMES FOR THE CURRENT AA PERIOD

Consumption	2011/12 actual	2012/13 actual	2013/14 actual	2014/15 forecast	2015/16 forecast	Total
Actual/forecast (terajoules)	7,437	7,571	6,994	6,721	6,447	**35,170**
Benchmark (terajoules)	7,668	7,528	7,363	7,272	7,231	**37,062**
Variance (terajoules)	-231	43	-369	-551	-784	**-1,892**
Variance (%)	-3%	1%	-5%	-8%	-12%	**-5%**

Note: Totals may not add due to rounding.

The key reason for the ongoing gap between actual and benchmark volumes reflects the higher declines in actual average consumption relative to the benchmark assumptions. Declining average consumption is due to a range of factors, including the trend towards warmer weather, the continued shift towards electric reverse cycle air-conditioning and the emergence of new and more efficient technologies. These factors are discussed in more detail in Chapters 2 and 14 of this AAI.

Table 4.9 compares actual and benchmark residential customer numbers. As with volumes, residential customer numbers have also consistently fallen below benchmark levels over the current AA period. By the end of the current AA period, residential customer numbers are expected to be around 2% less than the benchmark, which reflects the subdued housing construction market over this period and, in 2015/16, the removal of zero consuming meters. [28]

TABLE 4.9: ACTUAL VERSUS BENCHMARK RESIDENTIAL CUSTOMER NUMBERS FOR THE CURRENT AA PERIOD

Customer Numbers	2011/12 actual	2012/13 actual	2013/14 actual	2014/15 forecast	2015/16 forecast
Actual/forecast	400,460	406,873	412,860	418,754	420,828
Benchmark	400,952	407,857	415,073	422,642	430,824
Variance	-492	-984	-2,213	-3,888	-9,996
Variance (%)	0%	0%	-1%	-1%	-2%

Note: Totals may not add due to rounding.

4.7.2 Commercial Customers

Table 4.10 compares actual and benchmark volumes in the commercial segment for the current AA period. The table shows that the volumes distributed to commercial customers were below benchmark levels for all years of the current AA period. Overall, commercial volumes are expected to be 9% below benchmark levels. Like residential volumes, AGN has consistently been unable to achieve the benchmark commercial volumes over the past 16 years.

TABLE 4.10: ACTUAL VERSUS BENCHMARK COMMERCIAL VOLUMES FOR THE CURRENT AA PERIOD

Consumption	2011/12 actual	2012/13 actual	2013/14 actual	2014/15 forecast	2015/16 forecast	Total
Actual/forecast (terajoules)	3,029	3,069	3,008	2,918	2,877	**14,901**
Benchmark (terajoules)	3,196	3,286	3,264	3,283	3,345	**16,374**
Variance (terajoules)	-167	-217	-256	-365	-468	**-1,510**
Variance (%)	-5%	-7%	-9%	-13%	-16%	**-9%**

Note: Totals may not add due to rounding.

The key reason for the negative variance between actual and benchmark volumes in the commercial customer segment is the relatively weak economic conditions experienced in South Australia. The average Gross State Product growth rate for the current AA period to date (on average around 1.2%)[29] has been under half that assumed when setting the benchmarks (2.9%).[30]

Table 4.11 compares actual and benchmark commercial customer numbers. This shows that actual customer numbers are expected to be around 8% below benchmark levels by the end of the current AA period. As per residential connections, the decrease in customer numbers in 2015/16 in part reflects the removal of zero consuming meters.[31]

28 Zero consuming meters refer to those connections for which there is no associated consumption of natural gas. This situation may occur if a property is vacant or if supply has been cut off as a result of non-payment. See Chapter 14 of this AAI for further discussion on zero consuming meters.

29 BIS Shrapnel 2015, "*Real Labour Cost Escalation Forecasts to 2020/21*", January 2015, pg. 14.

30 AER 2011, "*Envestra Ltd: Access Arrangement Proposal for the SA gas network, 1 July 2011 – 30 June 2016*", Final Decision, June 2011, pg. 105.

31 Zero consuming meters refer to those connections for which there is no associated consumption of natural gas. This situation may occur if a property is vacant or if supply has been cut off as a result of non-payment. See Chapter 14 of this AAI for further discussion on zero consuming meters.

TABLE 4.11: ACTUAL VERSUS BENCHMARK COMMERCIAL CUSTOMER NUMBERS FOR THE CURRENT AA PERIOD

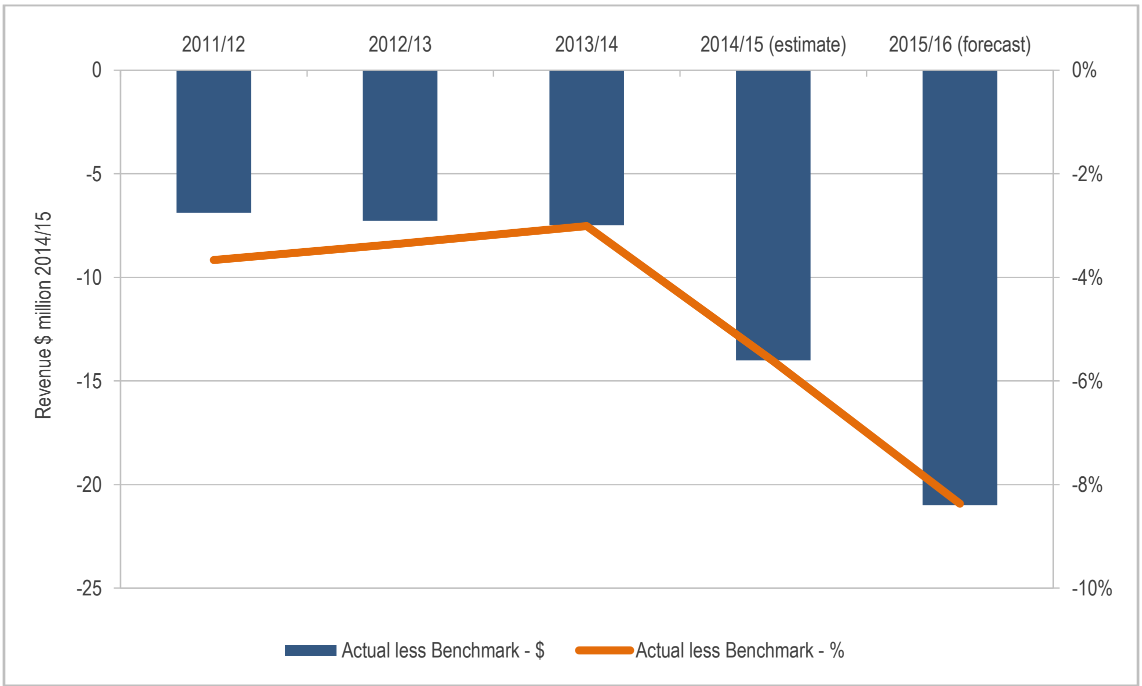
Customer Numbers	2011/12 actual	2012/13 actual	2013/14 actual	2014/15 forecast	2015/16 forecast
Actual/forecast	10,068	10,189	10,446	10,587	9,983
Benchmark	10,098	10,329	10,561	10,641	10,772
Variance	-30	-140	-115	-54	-789
Variance (%)	-0%	-1%	-1%	-1%	-8%

Note: Totals may not add due to rounding.

4.8 Revenue

Figure 4.3 shows that, consistent with previous AA periods, AGN has not been able to recover the benchmark revenue set by the regulator. In the current AA period, actual revenue recovery will be $57 million (or 4%) lower than the benchmarks that were set by the AER. As discussed earlier, this reflects the inability of AGN to achieve the volume and customer number forecasts set by the AER, which has been an ongoing challenge for the business.

FIGURE 4.3: ACTUAL VERSUS BENCHMARK REVENUE FOR THE CURRENT AA PERIOD



4.9 Summary

AGN's actual opex and capex are expected to be around 9% and 12% respectively below the benchmarks that were set by the AER for the current AA period.

As in previous periods, the natural gas volumes distributed through the Network are expected to be below the benchmarks. This has been a persistent trend, with actual residential volumes only exceeding benchmark levels once over the past 16 years. The inability to achieve benchmark volumes is primarily driven by average annual consumption falling at a faster rate than assumed by the benchmarks.

This shortfall in demand has led to actual revenue being $57 million (or 4%) below the allowed revenue for the current AA period. This shortfall in revenue erodes the financial incentive/benefit provided to AGN to improve operating efficiency. Despite the shortfall in revenue, AGN has:

- continued to deliver high levels of customer safety, reliability and service over the current AA period; and
- achieved robust productivity growth rates over the past 15 years.

AGN considered whether to propose revenue cap regulation for the next AA period given the ongoing inability to achieve the benchmark volumes (and hence revenue) set by the regulator. AGN has, however, decided to retain price cap regulation on the basis that this form of regulation places a stronger incentive on business growth (because revenue increases if gas sales increase under a price cap). This growth incentive is considered important given that gas is a fuel of choice.

The decision to continue with price cap regulation is, however, based on AGN being provided with a reasonable opportunity to achieve the customer number and volume forecasts over the next AA period. To this end, AGN considers that its customer number and volume forecasts, which are heavily based on past trends, reflect best estimates that are arrived at on a reasonable basis (these forecasts are set out in Chapter 14 of this AAI).

Part B
Our Proposal

Page intentionally left blank

5 What we will Deliver

Australian Gas Networks

Page intentionally left blank

5 What we will Deliver

5.1 Introduction

Australian Gas Networks Limited's (AGN's) vision is to be the leading natural gas distributor in Australia. Our Vision Statement sets out the following key objectives consistent with achieving this goal:

- *delivering for customers* – which means ensuring public safety and providing 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* – undertaking the required scope/volume of work within the benchmarks set by the Australian Energy Regulator (AER) while growing the South Australian natural gas distribution network (the Network) in a prudent and efficient manner.

As outlined in Chapter 2, over the current (2011/12 to 2015/16) Access Arrangement (AA) period we have delivered against the targets set out in our Vision Statement, including by providing high levels of safety, network reliability and customer service. 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.

We plan to continue to deliver high performance levels over the next (2016/17 to 2020/21) AA period. This chapter sets out what we will deliver over the next AA period against our Vision Statement.

5.2 Delivering on our Vision

Figure 5.1 summarises the key deliverables that AGN intends to provide over the next AA period against the targets set out in our Vision Statement. In summary, AGN intends to:

- deliver lower distribution tariffs, on average, in real terms compared to current (2015/16) tariffs;
- maintain our current high levels of reliability and customer service, which is consistent with the feedback received during our stakeholder engagement program;
- explore ways that we can improve the security of supply to our customers, including those located in regional areas;
- improve and strengthen the incentives for the business to incur prudent and efficient operating and capital expenditure;
- 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; and
- complete the cast iron (CI) and unprotected steel (UPS) mains replacement program and continue with the targeted replacement of our high-density polyethylene (HDPE) network.

These matters are discussed in more detail in this chapter.

FIGURE 5.1: WHAT WE WILL DELIVER OVER THE NEXT AA PERIOD

	Which means….	2016/17 – 2020/21 Targets
Delivering for Customers	▪ Public safety ▪ Reliability ▪ Customer service	▪ Maintain high performance levels. ▪ Improve network resilience. ▪ Support customer growth. ▪ Plans informed by stakeholder engagement. ▪ Improve and strengthen network incentives.
A Good Employer	▪ Safety ▪ Employee engagement ▪ Skills development	▪ Continuous improvement: - Lost Time Injury Frequency Rate (LTIFR): less than 1.0 per million hours*. - Restricted duties rate: less than 15 days*. - Implementation of employee engagement program. - Training and compliance monitoring.
Sustainably Cost Efficient	▪ Doing the work within industry benchmarks ▪ Delivering profitable growth	▪ Lower distribution tariffs in real terms, with an initial 11% real cut. ▪ Complete cast iron and unprotected steel mains replacement (862 kilometres). ▪ Continued selective replacement of high-density polyethylene mains (411 kilometres).

** As discussed further in Section 5.4.*

5.3 Delivering for Customers

Delivering for customers means ensuring public safety and providing high levels of network reliability and customer service. AGN considers 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 Chapter 4, AGN has delivered high levels of network reliability and customer service over the current AA period. In summary, in respect of:

- *safety* – AGN has complied with the safety requirements set out in our Leakage Management Procedure;
- *reliability* – there has been, on average, only 15 major network interruptions per year and our System Average Interruption Duration Index (SAIDI) performance has improved over the past four years and is consistent with good industry practice[32]; and

[32] A "*major*" interruption is one that affects five or more customers and was attributable to our actions, asset condition or third party damage. SAIDI, which measures average minutes lost per 1,000 customers, has been declining over the 2010/11 to 2013/14 period).

- *customer service* – over 90% of customer calls to our emergency call centre are answered within 10 seconds.

AGN intends 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 through robust engagement with our stakeholders;
- maintaining our high performance levels;
- continuing to support network growth;
- improving the security of supply across the network; and
- strengthening the incentives to improve performance.

Each of these deliverables is described in further detail below.

5.3.1 Stakeholder Engagement

This AA Proposal is the first time that AGN has developed and implemented a dedicated stakeholder engagement program to inform the initiatives set out in this Access Arrangement Information (AAI).

AGN's stakeholder engagement program was carefully considered and developed having regard to the need to ensure our AA Proposal best meets the requirements of the National Gas Objective (NGO)[33]. As set out in our overarching Stakeholder Engagement Strategy, which is provided at Attachment 3.5 to this AAI, AGN has:

> *"…developed and published our stakeholder engagement strategy to transparently set out our approach to engaging with stakeholders. Importantly, we have sought to design our approach to stakeholder engagement such that it is consistent with the National Gas Objective (NGO) and the Australian Energy Regulator's (AER's) Customer Engagement Guideline."*

Our approach to stakeholder engagement comprised four phases (see Figure 5.2). The key features of each stage of our engagement program include:

- *Strategy Phase* – the development of an overarching Stakeholder Engagement Strategy, our more specific Stakeholder Engagement Strategy for South Australia and our dedicated stakeholder engagement website (which can be accessed at: http://stakeholders.agnl.com.au);
- *Research Phase* – holding five community workshops and numerous interviews with key stakeholders, with results distilled into 14 key stakeholder insights captured by Deloitte and published in the Deloitte Stakeholder Insights Report (see Attachment 3.9);
- *Implementation Phase* – internal review of the key feedback received during the research phase, culminating in the AGN Insights and Implementation report (Attachment 3.11) and this AA proposal for South Australia; and
- *Ongoing Engagement Phase* – a commitment by AGN to continually seek ways to improve our stakeholder engagement program and also to engage with our stakeholders on an ongoing basis.

---

33 Further information on the NGO is provided in Chapter 1 of this AAI.

FIGURE 5.2: AGN'S APPROACH TO STAKEHOLDER ENGAGEMENT AND ASSOCIATED KEY DELIVERABLES

Strategy	Research	Implementation	Ongoing Engagement
Ongoing communications with stakeholders			
For each region, in collaboration with our Reference Groups and key stakeholders including senior AGN and APA Asset Management (APA) Management, define who we will engage with and how, and the key issues for consultation.	Implement the South Australian engagement strategy. Design targeted engagement activities (for example, workshops) and educational material to enhance stakeholder participation (for example, fact sheets). Conduct research (generally with assistance of an independent expert) and capture and report on the findings and insights.	Incorporate stakeholder insights into Access Arrangement proposal and general business plans in collaboration with Reference Groups and senior management. Report on our implementation of the insights and conduct further stakeholder engagement to validate our response.	Report on the outcomes and effectiveness of previous engagement activities and plan the approach to ongoing engagement incorporating key learnings. Implement ongoing stakeholder engagement strategy – periodically engage with stakeholders to understand their concerns and values to direct proposals and plans.
Key deliverables			
South Australian engagement strategy	South Australian stakeholder insights report	South Australian Access Arrangement proposal	Ongoing stakeholder engagement strategy

Importantly, our stakeholder engagement program has not been used to underpin large increases in our proposed capital and/or operating expenditure. This reflects that there are sound asset management and/or commercial drivers underpinning the initiatives included in our AA Proposal. Rather, stakeholder engagement has been used to inform these initiatives, including the scope of a project (i.e. whether stakeholders value increases or decreases in current service levels).

AGN is confident that our AA Proposal reflects the feedback that we received during our stakeholder engagement program. More detailed information on our engagement program is provided in Chapter 3 of this AAI (and throughout this AAI more generally).

5.3.2 Maintaining High Performance Levels

As outlined in Chapter 4, AGN has delivered a high level of performance over the current AA period. This was recognised by the Essential Services Commission of South Australia (ESCOSA), who is responsible for developing the customer service and reliability standards that are to apply over the next AA period. ESCOSA, in its Final Decision on service standards for the next AA period, noted that AGN's service levels are already at high levels, and as a result, it is not necessary to introduce any new performance targets for the business:

> *"This review has determined that AGN's current service levels are appropriate and should be maintained for the 2016-2021 regulatory period.*
>
> *Participants in AGN's stakeholder engagement program were generally satisfied with AGN's gas distribution services and reluctant to pay for improvements to current service levels. High levels of customer satisfaction are further supported by the consistently low number of complaints received by AGN and the low proportion of complaints that required escalation to the Energy and Water Ombudsman SA [South Australia]."*[34]

Consistent with the above, AGN is proposing to maintain its high levels of customer service and reliability over the next AA period.

[34] ESCOSA, June 2015, *"Australian Gas Networks Jurisdictional Service Standards for the 2016-2021 Regulatory Period, Final Decision*", June 2015, pg. 1. Provided as Attachment 3.10 to this AAI.

5.3.3 Supporting Customer Growth

AGN is proposing to continue to connect new customers to the Network over the next AA period. Around 16% of our proposed capital expenditure (capex) relates to customer growth. AGN is required by the National Gas Rules (NGR) to ensure that the revenue received from a new customer connection is greater than the costs of that connection. This means that the prices charged by AGN to existing customers will decrease as the number of customers connected to the network increases.

AGN is proposing to connect more than 35,000 customers to the South Australian network over the next AA period (our customer connection forecasts are set out in Chapter 14).

5.3.4 Improving the Security of Supply

AGN is undertaking an extensive review of actions that it can take to improve the security of supply across the Network. This follows a major outage on the Epic Energy transmission line to Port Pirie on 12 April 2015, which resulted in the loss of natural gas supply to around 10,000 gas customers in Port Pirie and Whyalla for around one week (Whyalla receives supply from the same transmission line that supplies Port Pirie). The most recent outage in Port Pirie and Whyalla follows a similar outage that occurred around three years earlier in Whyalla.

It is reasonably common across the Network for large numbers of customers to receive natural gas from a single supply point, particularly in regional areas and in the outer suburbs of Adelaide. AGN is currently undertaking a detailed review to assess ways that the security of gas supply can be improved on the Network over the next AA period. AGN will discuss these proposals with relevant stakeholders, including the AER, once these proposals have been further developed.

AGN has included a cost-pass-through mechanism in its South Australian AA Proposal that allows AGN to recover the costs of any security of supply initiative that meets the relevant criteria in the NGR for the approval of capex and is approved by the AER during the next AA period. This matter is discussed further in Chapter 16 of this AAI.

5.3.5 Strengthening Incentives to Improve Performance

AGN is a strong supporter of effective, outcome based incentive arrangements as a way of improving the price and service outcomes provided to natural gas customers, which is consistent with promoting outcomes that better achieve the NGO. AGN is therefore proposing that a more comprehensive set of incentive arrangements apply over the next AA period.

More specifically, AGN is proposing to strengthen the existing incentives and introduce new incentive arrangements to apply over the next AA period, including:

- the retention of the AER's operating expenditure (opex) incentive scheme (referred to as the efficiency benefit sharing scheme or EBSS), albeit strengthened to provide an equal (50:50) sharing of efficiency gains/losses between AGN and consumers (AGN is currently only allowed to retain 30% of any efficiency gain/loss);
- the introduction of the AER's capex incentive scheme (referred to as the capital expenditure sharing scheme, or CESS), also modified to allow for an equal sharing of efficiency gains/losses in capex;
- the introduction of an incentive to promote lower cost and/or improved service delivery outcomes through innovation; and
- the introduction of a customer service incentive.

With respect to the expenditure incentives, AGN considers that symmetrical and continuous incentives should be applied to both capital and operating expenditure and not just to opex as is currently the case. In particular, the operation of the AER's EBSS and CESS in combination will ensure that the most efficient network solution is always taken because there is no bias towards one form of expenditure over another.

AGN is also proposing that the power of the incentives be strengthened to allow for an equal sharing of efficiency gains/losses between the business and consumers. This reflects that AGN has been subject to incentive regulation for some time and, similar to other businesses, ongoing efficiency improvements are more difficult (and costly) to achieve. Our proposal to strengthen the incentives is consistent with the evolution of similar incentive schemes that apply to natural gas and electricity network businesses in the United Kingdom (UK).

AGN considers, consistent with our stakeholder feedback, that the incentive arrangements to apply over the next AA period should also include appropriate incentives to improve customer service. There are, however, practical constraints to introducing effective customer service incentives in the next AA period, including the availability of data to inform such a scheme. Our intention therefore is to continue to engage with stakeholders, including the AER, to design and implement an incentive scheme to improve customer service during the next AA period (see Chapters 12 and 16).

Another key feature of our proposed incentive arrangements relates to the introduction of an innovation allowance, which is intended to overcome the barriers to innovation expenditure that arise as a consequence of the resetting of costs (and prices) on a periodic basis. Similar innovation allowances apply for electricity network businesses in Australia and also natural gas and electricity network businesses in the UK.

AGN considers that the NGO and the Revenue and Pricing Principles will be best achieved by enhancing the incentive arrangements that are to apply over the next AA period. Our proposed incentive arrangements are explained in Chapter 12 of this AAI.

5.4 A Good Employer

Employee (and public) safety is a key focus of the business. This is why AGN has incorporated safety targets in its Vision Statement. 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 from 1.3 to less than 1.0 lost time injury per million hours worked and to keep employee restricted duties rates at less than 15 days.[35] 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 in the Vision Statement), motivated to achieve and improve on targets and consider there is appropriate support from AGN 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 have received the appropriate training for the job they are undertaking for the business.

5.5 Sustainably Cost Efficient

Being sustainably cost efficient means delivering the required outputs within the expenditure benchmarks set by the AER 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;
- continuing to investigate and support network growth; and

[35] The Lost Time Injury Frequency Rate is the number of lost-time injuries (defined as an occurrence that resulted in a fatality, permanent disability or time lost from one day shift or more) over a year relative to the total number of hours worked (usually million hours worked) in that year.

- delivering lower distribution tariffs, on average, in real terms over the next AA period compared to current (2015/16) tariffs.

5.5.1 Continuing to Deliver our Mains Replacement Program

AGN is committed to completing the replacement of its ageing CI and UPS mains. AGN remains on track to meet its objective of replacing all of these mains by 2020/21. This AA proposal provides for 862 kilometres of CI and UPS mains to be replaced over the next AA period, which would eliminate all CI and UPS on the Network. This program is necessary to ensure the ongoing safe and reliable supply of natural gas to our South Australian customers, including by:

- reducing the risks to both public and employee safety and property damage associated with natural gas leakage from the Network;
- increasing network capacity by replacing low pressure with high pressure mains (which facilitates new customer connections and the ongoing shift towards instantaneous natural gas hot water appliances); and
- improving network reliability by reducing the incidence of unplanned outages on the network.

AGN has also commenced and will continue with the replacement of parts of the HDPE network over the next AA period.

This is partly in response to the failure old HDPE mains. AGN has allocated considerable resources to understanding the behaviour of this material and to developing appropriate integrity management strategies to manage this issue going forward (this is explained in more detail in our Mains Replacement Plan, which is set out in Attachment 8.2 to this AAI).

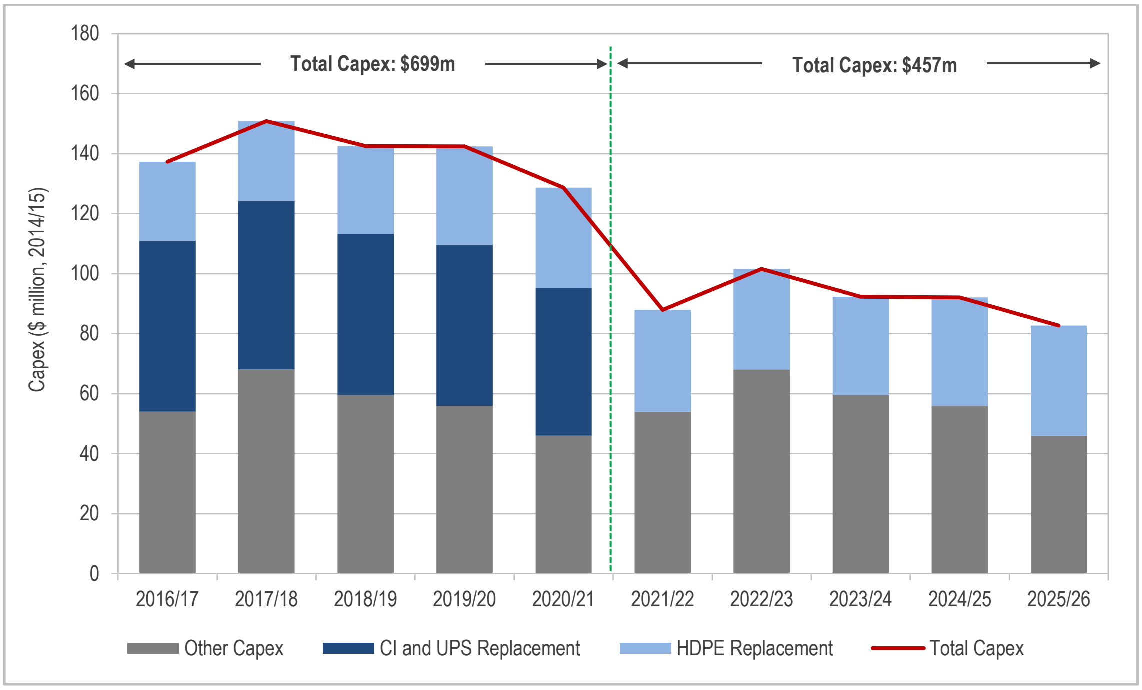
Our analysis has shown that the HDPE mains dating back to the 1970s are approaching the end of their useful life and are prone to failures under certain conditions. While the historic frequency of these types of failures is low, it is important that the risk be appropriately managed. To minimise the risk associated with the HDPE mains, the following actions are being pursued:

1. commence and complete in the current AA period 100 kilometres of HDPE mains replacement at various locations (AGN notes that this program was not anticipated at the time the benchmarks were set for the current AA period);
2. replace all medium pressure Class 250 HDPE mains within the Network by 2020/21;
3. replace high pressure Class 575 HDPE mains in a small number of locations;
4. research and development of pipe camera technology to identify defects, in order to better target replacement and repairs; and
5. develop a reliability forecast model to predict the remaining life of Class 575 HDPE, so that risk mitigation strategies, including replacement, can be optimised.

The majority (around 60%) of our proposed total capex relates to our mains replacement work program. This has the impact of maintaining our proposed capex at the levels experienced over the last two years (2014/15 and 2015/16) of the current AA period. AGN notes that the profile of its capex is, however, declining over the next AA period in line with the mains replacement program. Figure 5.3 shows that this declining capex trend can be expected to continue as the CI and UPS program is completed by the end of the next AA period.

As a consequence we would expect capex in the subsequent (2021/22 to 2025/26) period to fall compared to the two previous periods.

FIGURE 5.3: INDICATIVE CAPEX PROFILE, 2016/17 TO 2025/26



Note: The forecast capex profile from 1 July 2021 is based on a high level estimate that has been constructed by removing the CI and UPS and Class 250 mains replacement programs, which are both scheduled to be completed by 2020/21. This forecast is to be treated as indicative and is likely to change following the more detailed analysis that will occur over the next AA period.

The costs and benefits resulting from our mains replacement program will be recovered over a long period of time (these assets have a standard life of 60 years). Our mains replacement program is discussed in more detail in Chapter 8 of this AAI.

5.5.2 Investigating and Supporting Network Growth

AGN actively seeks to grow the Network, where this is in the long-term interests of consumers. As explained earlier, AGN must ensure that the revenue received from a new customer connection is greater than the costs of that connection before proceeding with any connection. Ultimately, this means that the prices charged by AGN to existing customers will decrease as the number of customers connected to the network increases.

During our stakeholder engagement program (Chapter 3), stakeholders supported expanding and improving the Network where there is a clear benefit to residents and business, but they wanted assurance that AGN would conduct an appropriate level of research prior to proceeding with any expansion. Having regard for stakeholder feedback and consistent with the NGO, AGN is committed to investigating and evaluating opportunities for reticulating gas in new areas of South Australia over the next AA period.

Our AA Proposal sets out provisions for a cost-pass-through event to ensure that should such a project be identified during the next AA period, AGN is able to apply to the AER to commence the project (see Chapter 16).

5.5.3 Lowering Distribution Tariffs

AGN is proposing to invest $699 million in capex and $353 million in opex over the next AA period. Despite our growing investment, AGN is proposing that our total revenue to be recovered will decrease by 9% (to $1,050 million) relative to the benchmark set for the current AA period. This is primarily driven by a proposed reduction in the rate of return, from 10.28% currently applying to 7.23% for the next AA period (see Chapter 10 for more information on our rate of return). This in turn reflects lower financing costs following the global financial crisis.

AGN has developed its proposed price path in order to:

- provide for revenue growth that, to the extent possible, matches the growth in the regulatory asset base (RAB) over the next AA period, which we consider is consistent with maintaining stable credit metrics (i.e. BBB+/Baa1) over the next AA period; and

- to equate revenue with our underlying costs in 2020/21 (the last year of the next AA period) to ensure that there is no one-off adjustment to tariffs (either positive or negative) required from 1 July 2021 to equate tariff revenue with costs.

This approach leads to an upfront price (i.e. tariff) cut on 1 July 2016, followed by price growth (i.e. in line with the growth in our RAB). More specifically, AGN is proposing to reduce tariffs by 11% in real (excluding inflation) terms on 1 July 2016, followed by tariff increases of 5% in real terms in each remaining year of the next AA period. Over the next AA period this results in lower distribution tariffs, on average, in real terms compared to current (2015/16) tariffs.

The 5% real price growth rate matches the growth in our RAB and therefore in our debt (at a constant debt-to-RAB ratio). This provides for stable credit metrics, such as the funds from operation (FFO) to debt ratio, which is important to maintaining a stable credit rating and therefore an efficient cost of capital. AGN engaged Incenta Economic Consulting (Incenta) to review our proposed price path against an alternative price path of having a one-off price adjustment and no real change in prices thereafter (Attachment 5.1). Incenta found:

> *"I find that AGN's proposed price path generates credit metrics that are much smoother over the period than the alternative path that was assessed, and also that AGN's proposal is expected to generate less of a price change between the next Access Arrangement period and the subsequent period (a real price reduction of 2.3 per cent compared to a price increase of 8.0 per cent). I therefore conclude that, out of the alternatives, AGN's proposed price path is superior both in terms of meeting the financeability objective and the price path objective."*[36]

The price path objective referred to in the above is concerned with minimising the difference between revenue and underlying costs while the financeability objective is concerned with ensuring the decision allows AGN to maintain the AER benchmark credit rating at BBB+/Baa1.

AGN also notes that the AER has a different view on the appropriate rate of return that should apply over the next AA period (this issue is discussed in more detail in Chapter 10). The AER in its recent Preliminary Decision for SA Power Networks set a rate of return of 5.45%, which is considerably less than that proposed by AGN. The AER rate of return, if applied to AGN, would have a material impact on our proposal given this component of cost accounts for around 50% of our proposed revenue.

More specifically, applying the AER rate of return of 5.45% would have the impact of reducing our proposed revenue to $880 million, which is $170 million (or 16%) less than that proposed by AGN for the next AA period (and around 24% less than benchmark revenue for the current AA period). This would in turn materially alter our proposed price path, resulting in a tariff reduction of 26% on 1 July 2016, followed by tariff increases of 5% thereafter (see Table 5.1).

---

36 Incenta Economic Consulting 2015, "*Using the Profile of Prices During an Access Arrangement Period and Return on Capital to Improve Financial Metrics*", 17 June 2015, pg. 3. Provided as Attachment 5.1 to this AAI.

TABLE 5.1: AGN PRICE PATH

	2016/17	2017/18	2018/19	2019/20	2020/21
AGN Proposed Price Path	-11.4%	5.0%	5.0%	5.0%	5.0%
AGN Adjusted Price Path (for AER rate of return)	-25.9%	5.0%	5.0%	5.0%	5.0%
AGN Adjusted Price Path (for AER rate of return) with financeability	-17.0%	5.0%	5.0%	5.0%	5.0%

Note: The AGN Adjusted Price Path is for illustrative purposes only. It reflects the AGN Proposal in full, but assumes the AER rate of return of 5.45% instead of the AGN rate of return (7.28%). The AGN Adjusted Price Path with financeability also assumes the AER rate of return of 5.45% but also assumes a depreciation adjustment, the need for which is discussed in further detail below.

AGN has explained in Chapter 9 that it would require a net present value-neutral adjustment to its depreciation profile over the next AA period if the AER rate of return of 5.45% (or similar) were to be applied to AGN. This depreciation adjustment is to ensure that the business has sufficient cash flow to maintain the AER benchmark BBB+/Baa1 credit rating over the next AA period and that the depreciation schedule satisfies Rule 89(1)(e).

As explained in Chapter 9, this depreciation adjustment is:

- required because the combination of the very low AER rate of return (AGN notes that 5.45% is the lowest rate of return set by the AER for any business), together with the AER approach of capitalising in the RAB the inflation component of the rate of return (which only provides for the real element of the return (i.e. 2.95%) to be paid in cash whilst the inflation element (i.e. 2.5%) is added to the RAB) does not provide enough cash flow to maintain the benchmark BBB+/Baa1 credit rating;

- consistent with the depreciation provisions set out in the NGR, specifically Rule 89(1)(e) which states that:

  "The depreciation schedule should be designed:

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

- simply altering the timing of cash flows rather than the present value of the revenue recovered by AGN over the life of its investment in the regulatory asset base.

The impact of this adjustment is also shown in Table 5.1 and would reduce the initial tariff reduction at the AER's rate of return to -17%.

This is consistent with the views of Incenta, who also found that a depreciation adjustment (or similar) was required in order to provided AGN with sufficient cash flow to maintain the AER benchmark BBB+/Baa1 credit rating. Specifically, Incenta stated:

> *"The clear conclusion from my assessment of AGN's credit metrics if a WACC [Weighted Average Cost of Capital] consistent with what was applied to SA Power Networks is applied and no other changes are made to improve financeability is that:*
>
> - *A stand-alone entity in AGN's positon would have credit metrics that are below what is required to attract and maintain a BBB+/Baa1 credit rating, and*
> - *Indeed the metrics are sufficiently poor that there is a material risk as to whether a BBB credit rating could be maintained.*
>
> *Accordingly, applying such a WACC without also applying measures to improve financeability would be inconsistent with the NGL [National Gas Law] and NGR, and most notably:*

- *Inefficiently raise the cost of finance, which is likely to be detrimental to the interests of users over the long term,*
- *Create a situation where a benchmark regulated business would not be able to earn a commercial return and recover at least its efficient cost because it would not be in a position to achieve the credit rating the AER has assumed; and*
- *Would not result in the service provider's legitimate needs for cash flow being met, and so is not consistent with rule 89(1)(c) of the NGR.*

My analysis suggests that if the provider is compensated fully for inflation in a cash sense, then this would be sufficient to generate credit metrics that are consistent with a BBB+/Baa1 rating, and which would endure over the 40 year forecast period that was analysed."[37]

In the absence of this financeability adjustment, AGN will find it difficult to access the capital required to deliver capex and opex at prudent and efficient levels, and will likely be downgraded below the AER benchmark BBB+/Baa1 credit rating (this is also consistent with our actual credit rating). Any decrease in AGN's credit rating would also lead to higher financing costs for the business, which is not in the long-term interests of consumers with respect to price.

In summary, in the event of a cut in the rate of return, AGN will require a depreciation adjustment in order to avoid these adverse outcomes, and as such, better achieve the requirements of the NGO.

---

[37] Incenta Economic Consulting 2015, "*Using the Profile of Prices During an Access Arrangement Period and Return on Capital to Improve Financial Metrics*", 17 June 2015, pg. 4-5. Provided as Attachment 5.1 to this AAI.

Page intentionally left blank

Part C
Derivation of Total Revenue

Australian Gas Networks

Page intentionally left blank

6 Pipeline Services

Australian Gas Networks

Page intentionally left blank

6 Pipeline Services

6.1 Introduction

The National Gas Rules (NGR) requires Australian Gas Networks Limited (AGN) to define in its Access Arrangement (AA) proposal the type and nature of pipeline services to be provided. Pipeline services include Reference Services and Non-Reference Services, where the former reflects those services that are likely to be sought by a significant part of the market. Reference services comprise Haulage Reference Services and Ancillary Reference Services.

This chapter describes the pipeline services to be provided by AGN over the next (2016/17 to 2020/21) AA period. The proposed pipeline services are the same as those currently applying to the South Australian natural gas distribution network (the Network).

6.2 Requirements of the National Gas Rules

Rule 48(1)(b) of the NGR provides that a full AA Proposal must describe the pipeline services that the distributor proposes to offer. Similarly, Rule 101 of the NGR states that a full AA must specify all reference services, where a reference service is a pipeline service that is likely to be sought by a significant part of the market.

These requirements of the NGR are set out in Sections 2.2 and 2.3 of the AA Document and explained in the remainder of this chapter.

6.3 Haulage Reference Services

AGN is proposing to continue to provide the following three Haulage Reference Services:

- *Domestic Haulage Service* – this service provides for the delivery of gas to Delivery Points (DPs) where natural gas is used primarily for domestic purposes;
- *Demand Haulage Service* – this service provides for the delivery of gas to DPs with an annual consumption that is equal to or greater than 10 terajoules per year; and
- *Commercial Haulage Service* – this service applies to all DPs that are not Demand DPs or Domestic DPs.

The above Haulage Reference Services include:

- receiving gas injected into the Network from an upstream pipeline at an injection point (referred to as a Receipt Point);
- odorisation of gas where required;
- haulage (or transport) of gas from a Receipt Point to a DP;
- allowing the withdrawal of gas at a DP;
- the provision and maintenance of a standard metering installation (this being the least cost technically acceptable meter and associated equipment that is able to measure and record the quantity of gas that is reasonably expected to be consumed by the customer at the DP); and
- meter reading and associated data services (every three months for Domestic and Commercial Haulage Services and daily for Demand Haulage Services).

The above Services include the provision of unaccounted for gas and all services that are necessary in order for AGN to comply with its obligations under the Access Arrangement and under the Retail Market Procedures. This includes a host of obligations that were introduced as a result of the National Energy Customer Framework in 2013.

AGN believes that the above Haulage Reference Services 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 July 2016.

6.4 Ancillary Reference Services

Ancillary Reference Services are those services that are specifically requested to be provided by a Network User (for example a retailer or some large industrial customers). Ancillary Reference Services are sufficiently common so as to be considered reference services. AGN is proposing to continue with the same Ancillary Reference Services that applied in the current (2011/12 to 2015/16) AA period, which include:

- *Disconnection* – installing locks or plugs at the Metering Installation of a Domestic DP in order to prevent the withdrawal of gas at the DP;
- *Reconnection* – restoring the ability to withdraw gas at a Domestic DP, following a previous Disconnection, which service includes the removal of any locks or plugs used to isolate supply, performance of a safety check and the lighting of appliances where necessary; and
- *Special Meter Read* – meter reading for a DP that is in addition to the scheduled meter reading that forms part of the Haulage Reference Service.

As explained in Chapter 3, AGN established a Retailer Reference Group to inform the development of its AA Proposal. AGN has accepted a request from the Retailer Reference Group to expand the Ancillary Reference Services provided to include the following three (additional) Ancillary Reference Services over the next AA period:

- *Meter and Gas Installation Test* – on-site testing to check the measurement accuracy of a Metering Installation and the soundness of the gas installation downstream of the Metering Installation;
- *Meter Removal* – removal of a meter at a Metering Installation in order to prevent the withdrawal of natural gas at the DP; and
- *Meter Reinstallation* – reinstallation of a meter at a Metering Installation, performance of a safety check and the lighting of appliances where necessary.

AGN notes that the above three Ancillary Reference Services are specified in our current Victorian AA. This change therefore provides for greater alignment of the Ancillary Reference Services provided across those networks that are owned by AGN.

6.5 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, cannot be classified as Reference Services. AGN will negotiate a price on a case-by-case basis, where the price will depend on the specific conditions attached to the provision of the service requested by the Network User.

If requested, the same Non-Reference Service would be offered to different Network Users on the same terms and conditions.

6.6 Service Standards

The requirement for AGN to provide a safe and reliable supply of natural gas underpins the regulatory framework governing the provision of gas distribution services. In addition to the services described in this chapter, AGN is required to comply with a range of safety standards that apply to the business, including but not limited to:

- odorisation of gas to prescribed levels;
- maintaining gas pressure within the Network above set levels;
- repairing gas leaks on the Network within prescribed times, which time depends on the severity or risk associated with the leak; and
- complying with the time periods for undertaking routine surveys of mains to check for leaks.

AGN will comply with all relevant safety standards over the next AA period.

AGN is required to routinely report on its compliance with the various safety requirements to various regulators, including the South Australian Office of the Technical Regulator. AGN is also required to regularly report on other aspects of its performance, including the network reliability performance and certain aspects of customer service. For example, AGN is required to report on:

- the number of unplanned interruptions on the network;
- the number of gas leaks; and
- the number and type of complaints made to AGN.

AGN supports such information requirements and notes that it is consistent with our own public reporting of key aspects of our service delivery under our Vision Statement (see Chapter 2).

Finally, AGN will provide services in a manner that is consistent with the terms and conditions that govern the supply of Reference Services to Network Users (as set out in Annexure G of our AA Document).

Page intentionally left blank

7 Operating Expenditure

Page intentionally left blank

7 Operating Expenditure

7.1 Introduction

This chapter sets out the forecast operating expenditure (opex) required by Australian Gas Networks Limited (AGN) over the next (2016/17 to 2020/21) Access Arrangement (AA) period. As required by Rule 91 of the National Gas Rules (NGR), the forecast opex is that required to be incurred by a prudent service provider, acting efficiently and in accordance with good industry practice to achieve the lowest sustainable cost of delivering Reference Services (as outlined in Chapter 6).

AGN has applied a 'base year roll-forward' approach to forecast opex over the next AA period. Under this approach, AGN has adjusted actual opex incurred in 2014/15 (the 'base year') for non-recurrent opex that is included in the base year, forecast changes in the cost of labour and materials and for costs that were not included in the base year, such as incremental costs resulting from forecast growth in customer numbers over the next AA period.

The 'base year roll-forward approach' to forecasting opex has been commonly accepted and applied by both AGN and the Australian Energy Regulator (AER). This largely 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 (see Chapter 12). This was confirmed by Economic Insights, which was engaged by AGN to compare our productivity performance against our peers.

This chapter sets out the relevant requirements of the NGR in relation to forecasting opex. This chapter then outlines the approach taken by AGN to develop its forecast opex for the next AA period, including a discussion of the base-year roll-forward approach and the approach to forecasting those costs that are not included in the base year.

7.2 Requirements of the National Gas Rules

Rule 91 of the NGR sets out the key criteria governing the recovery of opex. Rule 91 states:

> *"(1) Operating expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.*
>
> *(2) The AER's discretion under this rule is limited."*

In addition, Rule 74 of the NGR states:

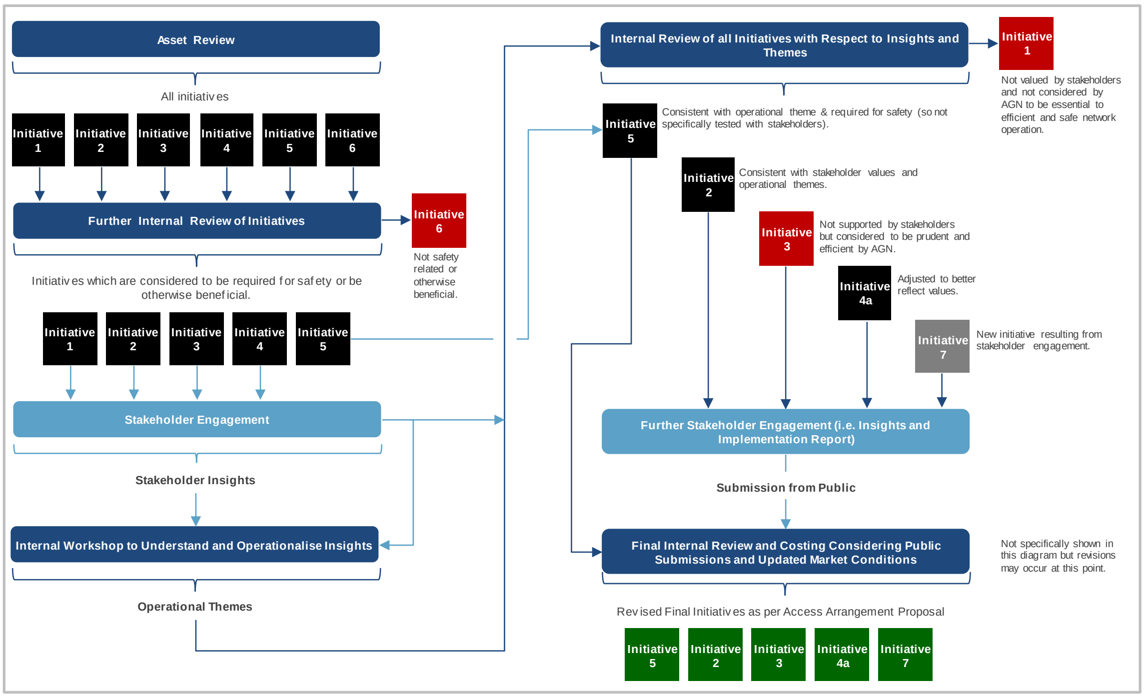
> *"(1) Information in the nature of a forecast or estimate must be supported by a statement of the basis of the forecast or estimate.*
>
> *(2) A forecast or estimate:*
>
> *(a) Must be arrived at on a reasonable basis; and*
>
> *(b) Must represent the best forecast or estimate possible in the circumstances."*

7.3 Stakeholder Engagement

AGN has developed and implemented a stakeholder engagement program to inform the initiatives that are set out in this AA Proposal. The key objective of our stakeholder engagement program, as explained in Chapter 3 of this Access Arrangement Information (AAI), is to ensure that our AA Proposal is reflective of stakeholder values and is consistent with promoting the requirements of the National Gas Objective (NGO).[38]

The results of the stakeholder engagement program were used to inform the initiatives (including Business Cases) set out in this AA Proposal, which includes the opex forecasts set out in this chapter. Importantly, all initiatives proposed by AGN have a sound asset management and/or commercial foundation (see Figure 7.1). Stakeholder engagement was used to inform the initiatives, such as the scope of a project and whether any proposed changes in service levels are consistent with stakeholder values.

FIGURE 7.1: IMPLEMENTATION OF STAKEHOLDER ENGAGEMENT RESULTS



Of particular relevance to the opex forecast, the stakeholder engagement program was used to inform the delivery of some initiatives through willingness-to-pay testing. In some cases, initiatives have been excluded from the opex forecast on the basis that they did not receive strong support from consumers. In other cases where consumer support was moderate, AGN has amended the scope and included the initiative on the basis that this is in the long-term interests of consumers.

There are also a number of initiatives proposed that were not specifically tested with consumers on the basis that the initiative is, based on prudent asset-management principles and fundamental to the ongoing safe and reliable supply of natural gas. AGN, however, considers that these initiatives are closely aligned with the operational themes developed in conjunction with our key stakeholders. The four operational themes[39], which were used to effectively integrate feedback into our AA Proposal, are:

- *include* – stakeholders want AGN to involve and include them by increasing the transparency of our operations, which will assist stakeholders to make more informed (and hence better) decisions regarding their energy supply;
- *maintain* – stakeholders value our high reliability and want us to keep providing the same (as a minimum) service levels;
- *improve* – stakeholders want AGN to explore ways that service can be improved, particularly as it relates to network safety; and

38 The National Gas Objective is further described in Chapter 1.

39 Further information on the AGN operational themes is available in the AGN Insights and Implementation Report (Attachment 3.11).

- *be efficient* – stakeholders are concerned with rising living costs and want AGN to promote efficient price outcomes for consumers of natural gas.

All Business Cases (and for the purposes of opex, all non-base year opex costs) have been informed by the four operational themes arising from our stakeholder engagement program.

7.4 Forecasting Approach

The approach taken by AGN to forecast opex is summarised in the following six steps:

1. *determine base year opex* – take opex in the most recent year for which actual information is available as a prudent and efficient base for forecasting opex over the next AA period, which in this case is opex incurred in 2014/15 (see Section 7.5);
2. *adjust base year opex* – adjust base year opex for those costs where the base year roll-forward approach does not produce best estimates that are arrived at on a reasonable basis:
    a. these costs, which are forecast separately, include certain payments made by AGN to its contractor (APA Asset Management (APA)), Ancillary Reference Services (ARS), insurance and unaccounted for gas (UAFG);
    b. the base year is also adjusted to remove one-off costs that are not anticipated to occur in every year of the next AA period (see Section 7.6);
3. *determine 2015/16 opex* – the adjusted 2014/15 base year opex is then adjusted for cost escalation to derive 2015/16 opex (see Section 7.7);
4. *identify non-base year opex* – identify those items that are not in the base year but are forecast to be incurred over the next AA period:
    a. this includes forecasts of costs removed in step two above and other non base year opex, such as changes in opex that are required to meet new regulatory obligations (see Section 7.8);
    b. further information on which is provided in the Business Cases outlined in Attachment 7.1;
5. *determine growth opex* – determine the incremental cost of supplying new customers that are forecast to be connected to the network over the next AA period (see Section 7.9); and
6. *apply cost escalation* – escalate forecast opex for expected changes in input costs (see Section 7.10).

The remainder of this chapter explains in more detail the application of the above steps to forecast opex over the next AA period.

7.5 Determine Base Year Operating Expenditure

As described above, the opex incurred by AGN in 2014/15 is used as the base year to determine the forecast opex for the next AA period. The 2014/15 base year incorporates the most recent actual information relating to the scope and cost of providing Reference Services over the next AA period (the Reference Services to be provided by AGN over the next AA period are described in Chapter 6 of this AAI).

AGN considers the significant commercial and regulatory incentives that apply to the South Australian natural gas distribution network (the Network), including through the application of the EBSS, work to ensure that 2014/15 opex reflects the prudent and efficient cost of providing Reference Services. As the AER has identified, the EBSS addresses two incentive issues that could have otherwise impacted base year opex if the EBSS was not in place:

> *"1. A NSP [Network Service Provider] has an incentive to increase opex in the expected 'base year' to increase its forecast opex allowance for the following regulatory control period; and*

2. *A NSP's incentive to make sustainable change to its practices, and reduce its recurrent opex, declines as the regulatory control period progresses. It then increases again after the base year [is] used to forecast opex for the following regulatory control period. By deferring these ongoing efficiency gains until after the base year the NSP can retain the benefits of doing so for longer because they won't be reflected in the opex forecasts for the following period."*[40]

The application of the EBSS over the current (2011/12 to 2015/16) AA period provides strong assurance that the 2014/15 base year reflects prudent and efficient opex.

This was confirmed by Economic Insights, which was engaged by AGN to compare the productivity performance of the Network relative to the performance of our peers (see Chapter 4). Of most relevance to the 2014/15 base year is the *Benchmarking Australian Gas Network' South Australian Business Operating and Capital Costs using Partial Performance Indicators* report prepared by Economic Insights (referred to as the Partial Indicator Report and provided as Attachment 4.2).

When constructing the specific Partial Performance Indicators (PPIs), Economic Insights has been guided by the following view expressed by the AER in its 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."*[41]

Taking this into consideration, in the Partial Indicator Report, Economic Insights presents the following PPIs, which are analogous to those published by the AER for electricity distribution businesses:

- opex per customer relative to customer density – where customer density is the total number of customers per kilometre of mains;
- asset cost per customer relative to customer density; and
- total cost per customer relative to customer density.

The comparative performance of the 'opex per customer relative to customer density' PPI is the most relevant when considering the efficiency of the 2014/15 base year.

Figure 7.2, which is taken from the Partial Indicator Report, shows that AGN has one of the lowest opex costs per customer relative to the other gas distribution networks that are included in the sample. Importantly, this operating expenditure performance has not come at the expense of higher capital expenditure and has been made despite less favourable operating environment conditions. In terms of the total cost per customer PPI, Economic Insights concluded that:

> *"AGN SA [South Australia] is a mid-sized GDB [Gas Distribution Business] that does not enjoy, to the same degree, the economies of scale attained by JGN [Jemena Gas Networks], the Victorian GDBs and ATCO WA [Western Australia]. For this reason, it should not be expected to outperform larger utilities. It also has an especially low energy density per customer. Nevertheless, comparisons of total cost per customer suggest that AGN SA's cost per customer is closely comparable to its peers, such as the three Victorian GDBs and JGN, which all have comparatively high customer density."*[42]

---

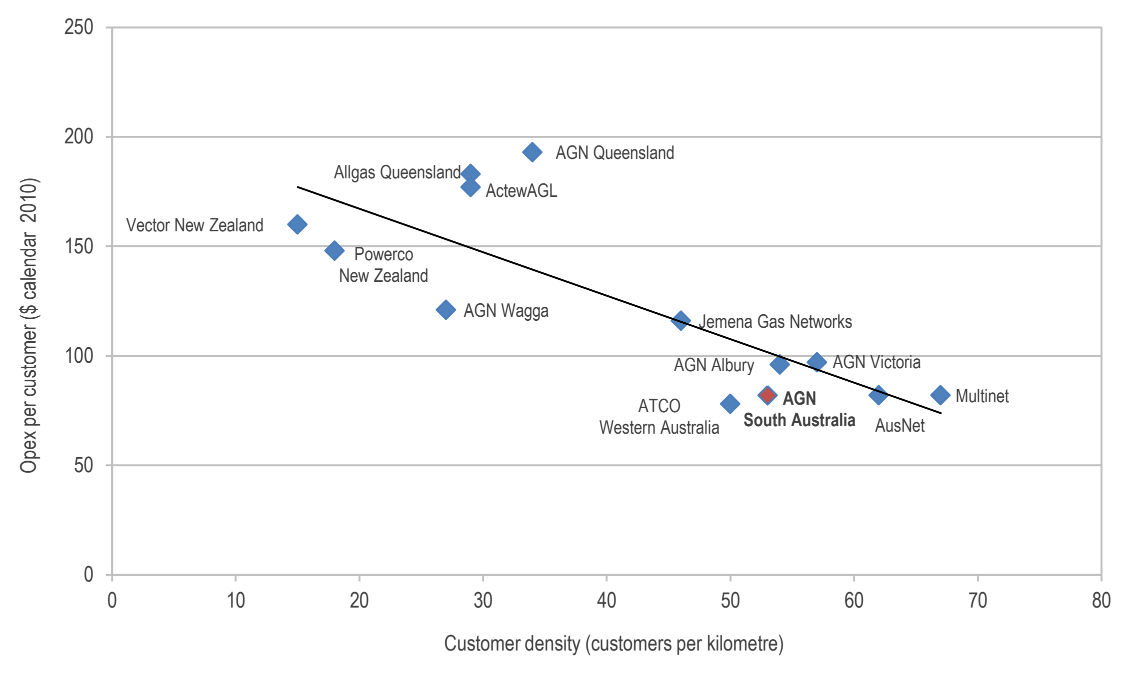
[40] AER 2013, "*Explanatory Statement Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*", November 2013, pg.5.

[41] AER 2014, "*Electricity Distribution Network Service Providers, Annual Benchmarking Report*", 2014, pg. 23.

[42] Economic Insights 2015, "Benchmarking Australian Gas Networks' South Australian Business Operating and Capital Costs Using Partial Performance Indicators", May 2015, pg. iv. Provided as Attachment 4.2 to this AAI.

Overall, our productivity performance supports the use of the 2014/15 base year to forecast opex over the next AA period.

FIGURE 7.2: OPEX PER CUSTOMER VERSUS CUSTOMER DENSITY



Note: All numbers in Figure 7.2 are averages 2007/08 to 2012/13.

Source: Economic Insights 2015, "Benchmarking Australian Gas Networks' South Australian Business Operating and Capital Costs Using Partial Performance Indicators", May 2015, pg. 9. Provided as Attachment 4.2.

The 2014/15 base year opex is estimated to be $65.9 million (expressed in 2014/15 dollar terms, also referred to as $2014/15).[43] The base year opex is necessarily an estimate as the 2014/15 year is not yet complete, with the estimate comprising nine months of actual opex and three months of estimated opex. AGN will update this information in its revised AA Proposal to incorporate 12 months of actual opex information.

The 2014/15 base year opex is broken down into various cost categories for the purpose of forecasting opex. These categories are consistent with that used by AGN and the AER for the current AA period, including for the purposes of the annual Regulatory Information Notices (RIN) submitted to the AER over the current AA period. The categories are as follows:

- *Operating and Maintenance Costs* – which includes Network operations management, Network maintenance, meter reading and billing, Network engineering and planning, Supervisory Control and Data Acquisition (SCADA), facilities management, Information Technology (IT) systems operations, the Network Management Fee (NMF) paid to APA and the licence fee;

- *Administration and General Costs* – which includes accounting and finance, human resource management and administration, regulatory functions and insurance costs;

- *Network Development Costs* – which includes costs that are incurred to maintain and grow both connection numbers and the volume of gas delivered through the Network; and

- *Unaccounted for Gas (UAFG)* – which comprises the cost of purchasing the gas that is lost across the Network.

43 From this point on, all dollar references will be in $2014/15 terms, unless otherwise specified.

7.6 Adjustment to Base Year Operating Expenditure

The 2014/15 base year opex described in Section 7.5 is adjusted to take account of:

- a one-off (or non-recurrent) expense that may not recur in every year of the next AA period; and
- where the 'base year roll forward approach' is not the best (or most reasonable) approach to forecast a particular cost.

The costs related to the above two factors are discussed in this section.

7.6.1 Non-Recurrent Operating Expenditure

In April 2015, a failure on the transmission pipeline (not owned by AGN) resulted in a loss of supply to the regional townships of Port Pirie and Whyalla. AGN has reviewed the 2014/15 base year opex and determined that the costs incurred due to this supply interruption are not likely to reoccur in every year of the next AA period. AGN incurred operating expenses estimated to be $0.7 million in relation to this interruption, which costs have been removed from the base year.

AGN does, however, have some reluctance to remove the costs associated with the recent supply interruption in Port Pirie and Whyalla given that a similar outage occurred around three years earlier in Whyalla. AGN also notes that there are no cost allowances included elsewhere in our AA Proposal should a similar outage occur over the next AA period. AGN has ultimately removed this amount from the base year on the basis that:

- such costs are unlikely to be incurred in every year of the next AA period; and
- AGN has proposed that a cost-pass-through mechanism be introduced that allows AGN to recover the costs of any initiative that improves the security of supply of the Network (see Chapter 16).

7.6.2 Specific Adjustments

AGN has also removed from the 2014/15 base year certain opex costs whereby the 'base-year roll-forward approach' does not provide a reasonable forecasting approach. This relates to the NMF ($7 million), ARS ($2 million), insurance ($0.5 million) and costs relating to UAFG ($9 million). These adjustments, net of the removal of the non-recurrent opex explained in Section 7.6.1, result in an adjusted 2014/15 base year opex of $46 million.

The approach to forecasting the NMF, ARS, insurance and UAFG, including the resultant forecasts, are explained in the following sections.

7.6.2.1 Network Management Fee

As explained in Chapter 2, AGN outsources operating, maintenance and construction services to APA. Under the terms of the 2007 Operating and Management Agreement, AGN pays APA its reasonably incurred costs of providing operating services, the NMF and certain incentive payments which, consistent with previous AER decisions, have not been included in the opex forecast.

Unlike most other costs, the NMF has been removed from base year opex as it is not linked to forecast changes in labour and materials costs. Rather, the NMF is determined as 3% of the revenue related to providing services on the Network. AGN has therefore forecast the NMF by calculating 3% of the building block revenue (prior to the inclusion of the NMF) to be recovered over the next AA period (the forecast building block revenue is discussed in Chapter 13).

The amount of the NMF forecast to be incurred over the next AA period is set out in Table 7.1. AGN notes that the NMF declines from 2015/16 to 2016/17 as a result of the forecast decline in revenue over the next AA period. This amount has been added back to forecast operating expenditure for the next AA period.

TABLE 7.1: NETWORK MANAGEMENT FEE FORECAST

$2014/15 million	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	5 Year Total
Network Management Fee	6.9	5.8	6.1	6.5	6.9	7.4	**32.8**

Note: Totals may not add due to rounding.

7.6.2.2 Ancillary Reference Services

As with the NMF, Ancillary Reference Services (ARS) costs are forecast separately as their rate of growth is more closely linked to the growth in customer numbers as opposed to changes in material and labour costs. As explained in Chapter 6, the cost of providing ARS is directly passed on to the customer requesting the service. The cost of providing ARS is forecast to remain constant in real terms and is determined by multiplying the forecast unit rate and volume of services to be provided over the next AA period. The forecast cost of providing ARS is set out in Table 7.2.

TABLE 7.2: OPEX FOR ANCILLARY REFERENCE SERVICES FORECAST

$2014/15 million	2016/17	2017/18	2018/19	2019/20	2020/21
Disconnection	0.45	0.45	0.46	0.46	0.47
Reconnection	0.34	0.34	0.34	0.35	0.35
Special Meter Reads	1.24	1.26	1.27	1.29	1.31
Meter Removal	0.10	0.10	0.10	0.10	0.10
Meter Reinstallation	0.01	0.01	0.01	0.01	0.01
Meter Gas and Installation Test	0.03	0.03	0.02	0.02	0.03
Total	**2.16**	**2.18**	**2.21**	**2.23**	**2.26**

Note: Totals may not add due to rounding.

7.6.2.3 Insurance

AGN engaged its insurance broker, Marsh & McLennan, to provide an estimate of our property and public liability insurance costs (the major insurance costs) through to 2020/21. Those estimates indicated there would be a real increase in insurance premiums consistent with the growth in the RAB, and has been reflected in the opex forecast shown in Table 7.3. The broker report is contained in Attachment 7.2.

TABLE 7.3: OPEX FOR PROPERTY AND PUBLIC LIABILITY INSURANCE FORECAST

$2014/15 million	2016/17	2017/18	2018/19	2019/20	2020/21
Property & Liability Insurance Premium	0.5	0.5	0.5	0.5	0.5
Real Increase to Premium	0.1	0.2	0.2	0.3	0.3
Total	**0.6**	**0.7**	**0.7**	**0.8**	**0.8**

Note: Totals may not add due to rounding.

7.6.2.4 Unaccounted for Gas (UAFG)

UAFG costs are determined as the product of forecast UAFG volumes and the price of gas purchased to supply UAFG.

UAFG volumes have fallen by 34% over the current AA period, largely as a result of our mains replacement program. AGN, based on expert advice from Asset Integrity Australasia (provided as Attachment 7.3), has forecast ongoing reductions in UAFG volumes over the next AA period. AGN also received expert advice on UAFG prices, which are forecast to increase, on average, by around 50% relative to the prices that prevailed in the current AA Period.[44]

Overall, the impact of increasing UAFG prices will offset any benefit that consumers would have otherwise received from the decrease in UAFG volumes. The increase in UAFG costs accounts for around half of the forecast increase in opex over the next AA period. Moreover, UAFG accounts for around 16% of total forecast opex over the next AA period. Forecast UAFG cost is set out in Table 7.4.

TABLE 7.4: UNACCOUNTED FOR GAS (UAFG) OPEX FORECAST

	2016/17	2017/18	2018/19	2019/20	2020/21
Total ($2014/15 million)	10.5	11.3	11.6	11.2	10.8

AGN is currently participating in an industry consultation process with other stakeholders, including retailers, self-contracting users and the Australian Energy Market Operator (AEMO), to amend the Retail Market Procedures to align the treatment of UAFG in South Australia (and Queensland) with the arrangements that apply in Victoria. This proposal would involve:

- transferring the responsibility for supplying UAFG in South Australia from the distributor to retailers and self-contracting users; and
- implementing an incentive regime that rewards (penalises) the distributor if actual UAFG volumes are lower (higher) than the benchmark.

In AGN's view, this proposal will result in lower price outcomes for consumers, and as such, better promote the NGO. This is because:

- retailers and self-contracting users are best placed to manage (and hence minimise) the cost of UAFG purchases; and
- distributors are best placed to manage (and hence minimise) the volume of gas losses on their networks.

AGN expects AEMO (the responsible body for this matter) to make a decision on this proposal by the time our Revised AA Proposal is submitted to the AER in early 2016. This will provide AGN sufficient time to remove from its forecast opex the UAFG forecast set out in Table 7.3 prior to the start of the next AA period.

7.7 Determine 2015/16 Operating Expenditure

The adjusted 2014/15 base year is then adjusted for the costs associated with customer growth (see Section 7.9) and forecast changes in labour and materials costs (see Section 7.10) to determine 2015/16 opex of $47 million.

7.8 Non-Base-Year Operating Expenditure

This section sets out opex that is not included in the 2014/15 base year but is forecast to be incurred over the next AA period. There are essentially four reasons why such expenditure may not be reflected in the base year, including that the opex:

1. is associated with the delivery of a particular capital project; or
2. arises from a one-off (opex) project; or

[44] See Attachment 14.1 to this AAI for further information on forecast natural gas prices.

3. represents a permanent (or step) change in opex (for example, arising from a change in a service standard or regulatory obligation).

The remainder of this section discusses each of the proposed non-base-year opex in relation to the above four categories, which are summarised in Table 7.5. The Businesses Cases provided in Attachment 7.1 provide the more detailed justification of the proposed non-base-year opex, including the detailed project background, justification against the relevant requirements of the NGR, the options considered by AGN and the prudent and efficient forecast cost of the project.

TABLE 7.5: NON-BASE-YEAR OPEX FORECAST

Category	Name	Business Case	$2014/15 million	
			5 Year Total	Annual Average
Capital expenditure-related opex	Development of AGN Digital Capabilities	SA84	$1.5	$0.3
	Information Technology – Geospatial Information System and Mobility	SA58 & SA59	$0.9	$0.2
	Remote Meter Reading	SA64	$0.5	$0.1
One-off opex projects	Gas Vents on High-Density Polyethylene Mains	SA56	$0.9	$0.2
	Monarto Front-End Engineering and Design Study	SA77	$0.3	$0.1
Step changes in opex	Ongoing Risk Management of High-Density Polyethylene	SA54	$3.2	$0.6
	Inlet Data Capture	SA44	$1.7	$0.3
	Stakeholder Education and Advocacy	SA83	$1.0	$0.2
Total			**$10.1**	**$2.0**

Note: Totals may not add due to rounding.

7.8.1 Development of Non-base-Year Operating Expenditure

As noted in Chapter 1, the forecasts and estimates used in this AA Proposal have been subject to a rigorous verification process, including that:

- forecasts are based on the considerable expertise of AGN and its contractor, APA;
- forecasts for projects have been based on robust Business Cases that have been subject to thorough review as to their compliance with the relevant requirements of the National Gas Law and NGR;
- where possible, forecasts have been based on the most recent actual information available, which information reflects revealed efficient expenditure/outcomes;
- all relevant drivers of a particular forecast have been taken into account and explained in this chapter and related Business Cases, including by providing any data used to derive a particular forecast;
- reliance has been made on independent expert advice in the preparation of forecast information, which advice has been attached to this AAI; and
- relevant industry stakeholders have been consulted, where appropriate, in deriving a forecast, plan and/or estimate.

AGN considers that the non-base-year opex outlined in this section satisfies the relevant requirements of the NGR, including that the proposed expenditure is prudent, efficient and consistent with good industry practice to achieve the lowest sustainable cost to consumers.

7.8.2 Capex-Related Opex

There are several capex projects set out in Chapter 8 of this AAI that will also give rise to additional opex. The relevant projects are summarised below and explained in more detail in Chapter 8. The associated Business Cases are referenced for each project in Table 7.5.

7.8.2.1 Development of Digital Capabilities (Business Case SA84)

AGN is proposing to develop its digital communication capability in order to provide a digital platform for the delivery of online services and communications with stakeholders. Importantly, this project will align our service delivery capabilities to be consistent with other network businesses (and businesses operating in the economy more generally). This project will allow AGN to better engage with stakeholders, including around matters such as facilitating online customer connections and the notification of network outages.

The need to develop our digital capability was a key finding from our stakeholder engagement program. For example, the Deloitte Stakeholder Insights Report found that:

> *"Customers generally prefer digital channels for greater accessibility and convenience. They also commented that digital channels are cost effective and reduce paper waste, yet the call centre and traditional written communication (letters) were also ranked in the top five preferred communication channels.*
>
> *Customers expressed a desire for more communication from AGN and provided guidance on when they prefer immediate 'real-time' channels versus more traditional communications. Specifically, customers are seeking more personalised communications regarding issues affecting their supply, property or local area such as SMS, email and website notification for unplanned outages.*
>
> *For planned works, such as outages, meter replacements and mains replacements there is a preference for email as customers like to keep a record of these notices (traditional mail was also favoured for this reason)."*[45]

Our proposed digital strategy is therefore consistent with the findings of our stakeholder engagement program.

An increase in operating costs is required in order to support the digital programs being delivered over the next AA period (as explained in Chapter 8 and Business Case SA84 in Attachment 7.1).

7.8.2.2 Information Technology – Geospatial Information System and Mobility (Business Cases SA58 and SA59)

Additional opex will be required in order to effectively implement the IT systems and projects proposed in Chapter 8. These IT projects allow for the continuation of a national program of work that has been initiated over the current AA period. This program replaces old state-based IT systems that have been in place for over ten years 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 Australian jurisdictions in which AGN operates are being implemented in order to achieve the lowest sustainable costs by maximising the economies of scale available to AGN. Considerable progress has been made towards the nationalisation of the IT systems and infrastructure over the current AA period. The additional opex relates to this program of work and largely consist of IT service personnel who will implement the new:

- Geospatial Information System (GIS) – which system effectively provides a map of the Network infrastructure; and
- Mobility program – which provides a mobile communication platform to enable field worker mobility.

---

45 Deloitte 2015, "*Australian Gas Networks Stakeholder Insights Report*", February 2015, pg. 16. Provided as Attachment 3.9 to this AAI.

The anticipated cost savings resulting from these projects have been taken into account when determining the forecast cost of these projects.

7.8.2.3 Remote Meter Reading (Business Case SA64)

AGN considers there are significant potential benefits to:

- installing remote meter reading devices across the Network where access to existing manually read meters is problematic; and
- trialling this technology in new development areas to assess the efficiency gains and service improvements that could come from a wider deployment of remote meter reading devices.

While the majority of the expenditure on this project is capex related, it also includes some opex for internal IT support and hosting data. As detailed further in Chapter 8, this project was tested with customers during our stakeholder engagement program and based on feedback received during this program, we have redesigned the project to better align with stakeholder views.

7.8.3 One-off Opex Projects

There are two one-off (or non-recurrent) opex projects that are forecast to occur over the next AA period. The change in opex relating to these projects is not permanent. The associated Business Cases are referenced for each project in Table 7.5.

7.8.3.1 Gas Vents on High-Density Polyethylene Mains (Business Case SA56)

AGN is proposing to install gas vents on high-density polyethylene (HDPE) mains in order to assist in the detection of gas leaks at the earliest possible time. This measure will allow a more direct vent to the atmosphere, increasing the likelihood that the gas leak will be detected and reported either by the public or through regular leak surveys. This initiative is part of a suite of projects that are aimed at managing the risks associated with the HDPE parts of the network.

The costs for this initiative include the installation of 7,900 gas vents covering 274 kilometres of high pressure and medium pressure ‘Class 575’ HDPE mains. The proposed costs are considerably less than the alternate option of replacing these mains over the next AA period.

7.8.3.2 Monarto Front-End Engineering and Design Study (Business Case SA77)

A front-end engineering design (FEED) study will be undertaken to assess the feasibility of extending the Network to Monarto, which has been identified as an area where a number of load growth opportunities are or will be present. This project is supported by the local Murray Bridge Council’s infrastructure investment strategies to attract new industry to the area. The study is expected to be commissioned by 2018/19 and has the potential to contribute to the long-term interests of consumers on the Network.

During our stakeholder engagement program, customers indicated they were supportive of, and willing to pay for, AGN to explore network expansion activities (see Chapter 3).

7.8.4 Step Changes in Operating Expenditure

A step change in opex is a cost that AGN will be required to incur on an ongoing basis. AGN considers that in determining whether such a change in opex complies with the requirements of the NGR outlined in Section 7.2, it is necessary to demonstrate that the increased costs are driven by:

- a change in the business environment arising from external factors (e.g. attributable to the imposition of new or changed obligations); or
- an initiative to improve service levels in a manner that is in the long-term interests of consumers; or

- an initiative to reduce long-term costs to consumers; or
- an initiative to improve the safety of network service provision.

Each of the proposed step changes are described in more detail in Sections 7.8.4.1 to 7.8.4.3.

7.8.4.1 Ongoing Risk Management of HDPE (Business Case SA54)

As noted earlier, including in Chapter 5, it is necessary to mitigate risks associated with older parts of the HDPE network. As a result of analysis into old HDPE, it is evident that further work is required to determine the properties of this material as it ages.

The costs of this step change, which is focused on improving public safety, provides for an additional three engineering resources and additional pipe sampling and testing resources. The additional resources will be used to optimise various risk management initiatives as well as develop an evidence-based integrity management strategy that is aimed at optimising the maintenance and replacement programs associated with the oldest HDPE pipe on the Network.

This project therefore seeks to ensure that any risk mitigation activities are consistent with good industry practice and achieve the lowest sustainable cost to consumers.

7.8.4.2 Inlet Data Capture (Business Case SA44)

AGN intends to capture the geographic details of inlet services to 9,800 existing Industrial and Commercial customers and 3,300 major unit development sites. This project has been timed to coincide with the implementation of the new GIS outlined in Business Case SA58. This project will aid operations staff and third parties to quickly access inlet services and, in the event of an emergency situation, will enable efficient emergency leak responses in order to minimise the potential for personal injury and/or third party damages.

7.8.4.3 Stakeholder Education and Advocacy (Business Case SA83)

AGN has designed and implemented a robust stakeholder engagement program to inform the initiatives described in this AA Proposal. This project builds upon the program of engagement already carried out and seeks to enable AGN to better respond to the changing needs of gas customers and stakeholders. The scope of this project incorporates the costs of funding our own advisory committee and to carry out new initiatives designed in response to feedback received during the stakeholder engagement program.

7.9 Growth Operating Expenditure

AGN will incur additional opex as the (net) number of customers added to the Network increases. AGN is forecasting to connect, on average, approximately 5,000 new customers to the Network each year and has included into the opex forecast an incremental cost to provide services to these new customers over the next AA period.

AGN has estimated an incremental cost per customer of $20 per connection. The approach taken to estimate the incremental cost is consistent with that approved by the AER for the current AA period and is explained in Attachment 7.4 to this AA Proposal. This cost is consistent with the incremental cost of $20 (expressed in $2014/15) published in the 2011 Victorian Gas Distribution System Code and was also accepted by the AER for our Victorian network.

AGN has applied the incremental cost of $20 per customer to forecast the costs associated with customer growth on the Network over the next AA period (see Table 7.6). Table 7.6 shows that net customer growth is forecast to be lower in 2015/16 and 2016/17 than in later years (2017/18 to 2020/21). This is driven by the assumed removal of zero consuming meters, which is described in further detail in Chapter 14.

TABLE 7.6: NET CUSTOMER GROWTH OPEX FORECAST

	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Incremental cost per new connection ($2014/15)	20.0	20.0	20.0	20.0	20.0	20.0
Forecast net customer growth (number of net new customer connections)	1,470	3,291	5,180	5,397	5,778	5,972
Total Net Customer Growth Opex ($2014/15 million)	**0.03**	**0.1**	**0.2**	**0.3**	**0.4**	**0.5**

Note: The "Total Net Customer Growth Opex" is cumulative.

7.10 Cost Escalation

Forecast operating expenditure has been split into labour and materials. The split between the two input cost categories is based on an average of the historical breakdown of actual expenditure for the 2011/12, 2012/13 and 2013/14 regulatory years (i.e. the years that actual information is available for the current AA period) and varies for each of the opex categories outlined in Section 7.5. This section describes the approach taken by AGN to forecast changes in labour and material inputs over the next AA period.

7.10.1 Labour

AGN has previously proposed that labour costs be adjusted by the annual change in the Average Weekly Ordinary Time Earnings (AWOTE) index, adjusted for labour productivity. The AER has rejected this approach and has instead applied the Wage Price Index (WPI) (formerly the Labour Price Index or LPI), unadjusted for labour productivity. AGN has accepted the AER-preferred methodology to account for changes in the price of labour for the next AA period.

AGN has engaged BIS Shrapnel to provide forecasts for the WPI in the Electricity, Gas, Water and Waste Services (EGWWS) industry in South Australia through to the end of the next AA period (i.e. 2020/21). AGN notes that using the EGWWS is likely to understate labour costs given, for example, the generally higher skills required in the gas sector relative to the waste services sector. Reliable data are, however, not available to develop more specific labour price forecasts for the South Australian gas sector.

Table 7.7 shows the BIS Shrapnel forecasts of real (or above-inflation) changes in the South Australian WPI for the EGWWS industry over the next AA period (see Attachment 7.5 for further detail). Table 7.7 also shows the same forecasts prepared by Deloitte Access Economics (DAE) as part of the AER's Preliminary Decision for SA Power Networks (SAPN). These forecasts are for the period ending 2019/20, which corresponds with the end of the next AA period for that business. An average of the two forecasts is also included in Table 7.7.

TABLE 7.7: SOUTH AUSTRALIAN ELECTRICITY, GAS, WATER AND WASTE SERVICES WAGE PRICE INDEX FORECAST

	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
BIS Shrapnel	0.90%	1.40%	1.32%	1.47%	1.67%	1.88%
Deloitte Access Economics	0.00%	0.20%	0.50%	0.60%	0.70%	†
Proposed Real Labour Cost Escalation Rate (Average)	**0.45%**	**0.80%**	**0.91%**	**1.04%**	**1.19%**	**1.88%**

†*Note: AGN does not have access to the Deloitte Access Economics forecast for 2020/21. As a result, AGN's proposed real labour cost escalation rate for 2020/21 is just BIS Shrapnel's forecast.*

AGN has applied the average of the BIS Shrapnel and DAE forecasts of changes in labour prices over the next AA period. The primary motivation for this approach is the recent AER Preliminary Decision in respect of SAPN, where the AER stated:

> *"Where a consultant is used to forecast labour prices, we consider an averaging approach that takes into account the consultant's forecasting history, if available, to be the best methodology for forecasting labour price growth."*[46]

To this end, AGN engaged Professor Jeff Borland as part of the most recent Victoria AA review process to assess the relative forecasting performance of both DAE and BIS Shrapnel and to advise on the appropriate forecast to use in our Victorian AA proposal (see Attachment 7.6). In his analysis, Professor Borland compared BIS Shrapnel and DAE forecasts of the national, all industries LPI and concluded:

> *"(a) There is a relatively large difference between forecasts made by BIS and DAE of changes to WPI in the utilities/EGWWS sector in Victoria for the 2013 to 2017. Hence which measure is chosen can have a substantial impact on the size of real labour cost escalation over the access arrangement period…;*
>
> *(b) Comparison of past forecasts of changes to LPI made by DAE and BIS against data on actual changes to LPI shows that: (i) There is no basis for concluding that forecasts made by DAE have had lower forecast error than those made by BIS; and (ii) A forecast that is an average of the DAE and BIS forecasts is associated with lower forecast error than using either the DAE or BIS forecasts …; and*
>
> *(c) Statistical theory supports that an average of the DAE and BIS forecasts is likely to be a superior approach to forecasting changes to WPI compared to using either the DAE or BIS [BIS Shrapnel] forecasts…."*[47]

Based on the AER's most recent Preliminary Decision for SAPN and the analysis and advice from Professor Borland, AGN has applied an average of the BIS Shrapnel and DAE forecast of changes in labour prices for the first four years of the next AA period. DAE has not, however, released its forecasts for 2020/21, and consequently, AGN has simply applied the BIS Shrapnel forecast. AGN anticipates that the AER will release DAE forecasts for 2020/21 in its Draft Decision for AGN, at which time the real labour cost escalation rate will be updated to reflect this value.

7.10.2 Materials

The AER has not in the past allowed for changes in material prices over and above the annual rate of change in inflation. AGN has also adopted this approach to forecast opex over the next AA period.

7.11 Summary

As set out in this chapter, forecast operating expenditure for the next AA period has been arrived at by:

1. determining base year opex by taking opex in the most recent year for which actual information is available, which in this case is 2014/15;
2. adjusting the 2014/15 base year opex for those costs where the 2014/15 base year roll-forward approach does not produce best estimates arrived at on a reasonable basis, which in this case relates to the NMF, ARS, insurance and UAFG;
    - AGN has also removed opex associated with the supply interruption to Port Pirie and Whyalla that occurred in April 2015 as this is unlikely to occur in every year of the next AA period;
    - the adjusted 2014/15 base year opex is $46 million;

[46] AER 2015, "*Attachment 7 – Operating expenditure" SA Power Networks*' Preliminary Decision 2015-20", April 2015, pg. 7-55.

[47] Borland 2012, "*Recommendations for Methodology for Forecasting WPI*", October 2012, pg. 3. Provided as Attachment 7.6 to this AAI.

3. escalating the adjusted 2014/15 base year opex for the costs associated with customer growth and for forecast changes in labour and material costs to derive 2015/16 opex of $47 million;

4. adding to this amount non-base year costs, the cost of meeting customer growth and cost escalation over the next AA period; and

5. adding forecast NMF, ARS, insurance and UAFG costs.

The resulting build-up of our forecast operating expenditure is shown in Table 7.8. Further information regarding the derivation of our opex forecast is provided in the opex forecast model, which has been provided as Attachment 7.7 to this AAI. The composition of our opex forecast is shown in Figure 7.3, which shows that the majority of our opex forecast is comprised of base year costs (66%), UAFG costs (16%), the NMF (9%) and non-base year costs (3%).

TABLE 7.8: BUILD-UP OF OPEX FORECAST

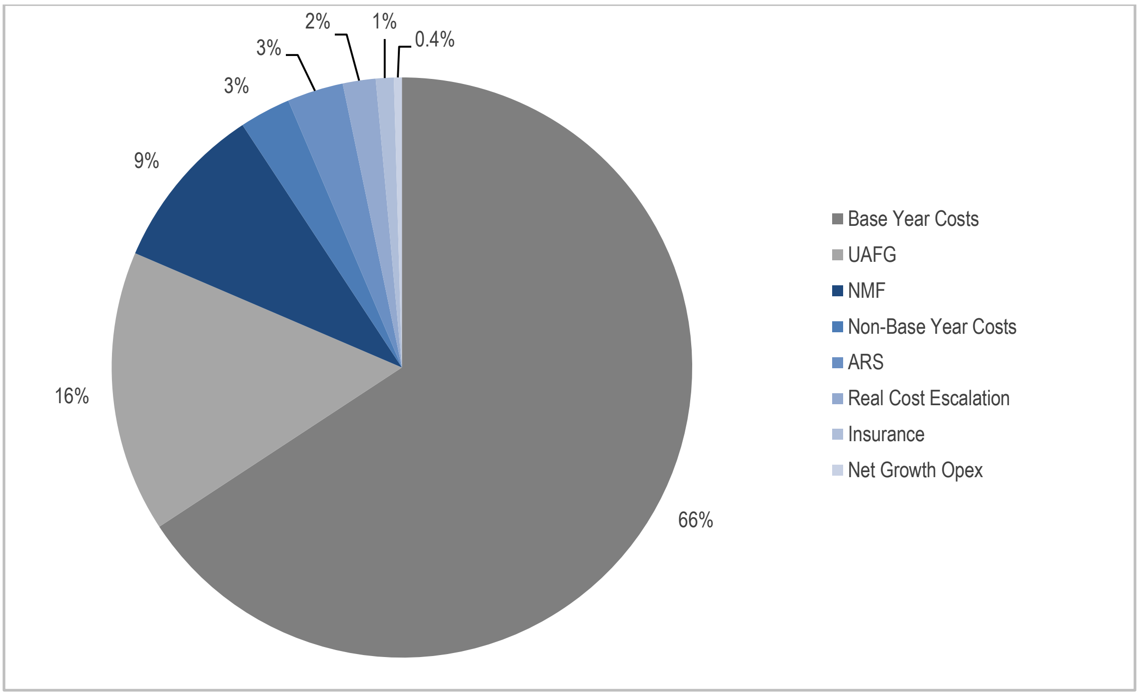
Opex Summary ($2014/15 million)	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Adjusted Base Year Opex	46.4	46.4	46.4	46.4	46.4	**231.9**
Non-Base Year Costs	1.5	2.0	2.5	2.1	1.9	**10.1**
Real Cost Escalation	0.5	0.8	1.2	1.6	2.4	**6.5**
Unaccounted for Gas	10.5	11.3	11.6	11.2	10.8	**55.4**
Ancillary Reference Services	2.2	2.2	2.2	2.3	2.3	**11.1**
Insurance	0.6	0.7	0.7	0.8	0.8	**3.5**
Net Growth Opex	0.1	0.2	0.3	0.4	0.5	**1.6**
Network Management Fee	5.8	6.1	6.5	6.9	7.4	**32.8**
Total	**67.5**	**69.7**	**71.5**	**71.7**	**72.4**	**352.7**

Note: Totals may not add due to rounding.

TABLE 7.9: OPEX FORECAST (REAL AND NOMINAL)

$ million	2016/17	2017/18	2018/19	2019/20	2020/21	Total
$2014/15	67.5	69.7	71.5	71.7	72.4	**352.7**
Nominal	70.1	74.2	78.0	80.2	83.0	**385.5**

FIGURE 7.3: COMPOSITION OF OPEX FORECAST



Note: Totals may not add due to rounding.

8 Capital Expenditure

Australian Gas Networks

Page intentionally left blank

8 Capital Expenditure

8.1 Introduction

Australian Gas Networks Limited (AGN) has determined the prudent and efficient capital expenditure (capex) that is required over the next (2016/17 to 2020/21) Access Arrangement (AA) period to comply with the requirements of the National Gas Rules (NGR). This includes the capex required to satisfy the forecast growth in demand for services, to maintain and improve safety, to maintain system integrity and to comply with all regulatory obligations that govern the safe and reliable supply of natural gas.

The capex program for the next AA period has been developed pursuant to our Asset Management Plan. The majority (around 60%) of our proposed capex relates to the delivery of our mains replacement program, which is one of the key drivers ensuring the ongoing safe and reliable supply of natural gas to the community. The mains replacement program has the additional benefit of allowing AGN to satisfy the forecast demand for natural gas over the next AA period.

Other key elements of our proposed capex relate to the connection of new customers to the South Australian natural gas distribution network (the Network) and the ongoing implementation of our national information technology (IT) strategy, which programs account for 16% and 10% of capex respectively. The remaining capex relates to projects such as our meter replacement program, augmentation and for the installation of equipment such as regulators and valves across the Network.

This chapter provides an overview of the relevant requirements of the NGR, the approach taken by AGN to develop its forecast capex and the key elements of the proposed capex program. This chapter should be read in conjunction with the Asset Management Plan, the Mains Replacement Plan, the Capacity Management Plan, the IT Plan and the underlying Business Cases that have been attached to the Access Arrangement Information (AAI).

8.2 Requirements of the National Gas Rules

Rule 78 of the NGR provides for the projected regulatory capital base to include forecast conforming capex for the period. Rule 79 states that:

> *"(1) Conforming capital expenditure is capital expenditure that conforms with the following criteria:*
>
> > *(a) the capital expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services;*
> >
> > *(b) the capital expenditure must be justifiable on a ground stated in subrule (2).*
>
> *(2) Capital expenditure is justifiable if:*
>
> > *(a) The overall economic value of the expenditure is positive; or*
> >
> > *(b) The present value of the expected incremental revenue to be generated as a result of the expenditure exceeds the present value of the capital expenditure; or*
> >
> > *(c) The capital expenditure is necessary:*
> >
> > > *(i) To maintain and improve the safety of services; or*
> > >
> > > *(ii) To maintain the integrity of services; or*
> > >
> > > *(iii) To comply with a regulatory obligation or requirement; or*
> > >
> > > *(iv) To maintain the service provider's capacity to meet levels of demand for services existing at the time the capital expenditure is incurred (as distinct from projected demand that is dependent on an expansion of pipeline capacity)."*

Rule 79 provides that the Australian Energy Regulator (AER) has limited discretion in assessing whether expenditure complies with Rule 79.

In addition, Rule 74 states that in relation to forecasts and estimates:

> *"(1) Information in the nature of a forecast or estimate must be supported by a statement of the basis of the forecast or estimate.*
>
> *(2) A forecast or estimate:*
>
> *(a) Must be arrived at on a reasonable basis; and*
>
> *(b) Must represent the best forecast or estimate possible in the circumstances."*

8.3 Stakeholder Engagement

AGN has developed and implemented a stakeholder engagement program to inform the initiatives that are set out in this AA Proposal. The key objective of our stakeholder engagement program, as explained in Chapter 3 of this AAI, is to ensure that our AA Proposal is reflective of stakeholder values and is consistent with promoting the requirements of the National Gas Objective (NGO).[48]

As explained in Chapters 3 and 7, all initiatives proposed by AGN have a sound asset management and/or commercial foundation (see Figure 7.1). The results of the stakeholder engagement program were used to:

- inform the initiatives (including Business Cases) set out in this AA Proposal, including the capex forecasts set out in this chapter;
- inform the scope of the initiatives, including whether any proposed changes in service levels are consistent with stakeholder values; and
- inform the delivery of some initiatives through willingness-to-pay testing, including whether to exclude or amend a proposed initiative where this would be in the long-term interested of consumers.

There were also a number of initiatives that were not specifically tested with consumers on the basis that the initiative is based on prudent asset management principles and/or fundamental to the ongoing safe and reliable supply of natural gas. AGN, however, considers that these initiatives are very closely aligned with the operational themes developed in conjunction with our key stakeholders. The four operational themes[49], which were used to effectively integrate feedback into our AA Proposal are:

- *include* – stakeholders want AGN to involve and include them by increasing the transparency of our operations, which will assist stakeholders to make more informed (and hence better) decisions regarding their energy supply;
- *maintain* – stakeholders value our high reliability and want us to keep providing the same (as a minimum) service levels;
- *improve* – stakeholders want AGN to explore ways that service can be improved, particularly as it relates to network safety; and
- *be efficient* – stakeholders are concerned with rising living costs and want AGN to promote efficient price outcomes for consumers of natural gas.

---

[48] The National Gas Objective is further described in Chapter 1.

[49] Further information on the AGN operational themes is available in the AGN Insights and Implementation Report (Attachment 3.11).

All Business Cases have been informed by the four operational themes arising from our stakeholder engagement program.

8.4 Development of the Capital Expenditure Program

The capex forecast has been developed using a 'bottom-up' approach, which has involved a detailed review of all aspects of the business to ensure that the proposed capex program complies with the requirements of the NGR. Interestingly, the stakeholder feedback aligns with the requirements of the NGR, particularly as it relates to maintaining current levels of supply reliability and customer service and investing in initiatives to improve public safety.

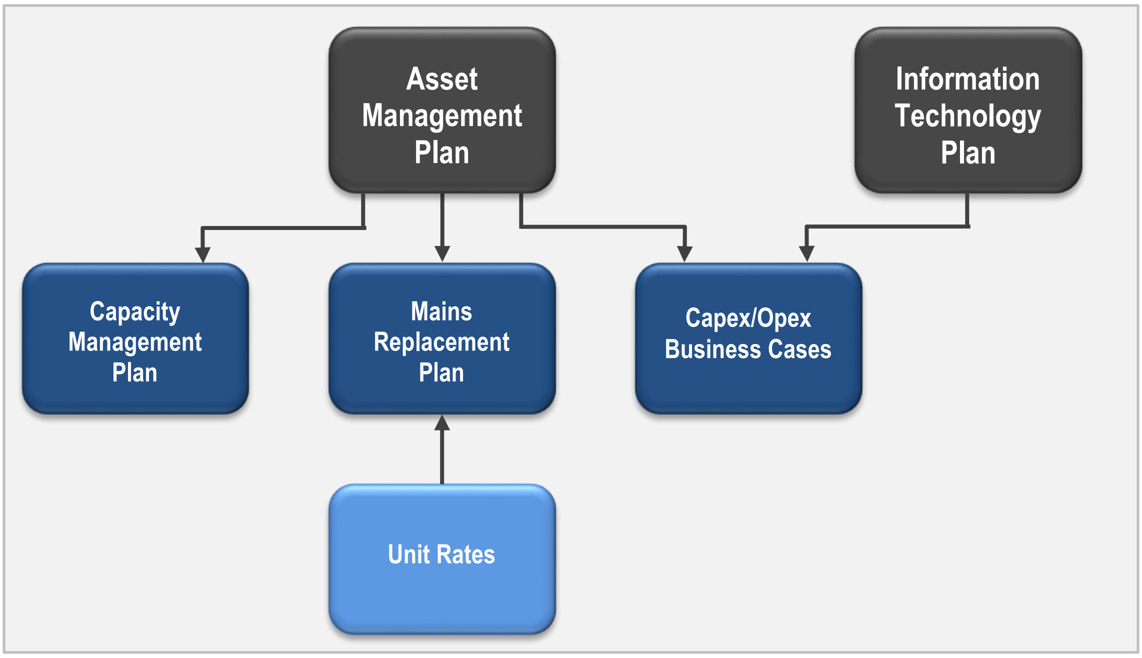
This section outlines the key business plans guiding the development of the capex program, the process followed by AGN to develop the scope of its capex program and the methods adopted to determine the cost of the capex program.

8.4.1 Overarching Business Plans

The capex program for the next AA period has been developed pursuant to our Asset Management Plan (AMP), which has been provided as Attachment 8.1 to this AAI.

The AMP provides a consolidated view of a number of technical and operational plans and describes how these plans are used to drive asset management strategies that are consistent with good industry practice (see Figure 8.1). Specifically, these strategies are designed to ensure the safe and reliable supply of natural gas in line with our regulatory obligations, effective risk management and in a manner that is consistent with achieving the lowest sustainable cost to consumers over the long term.

FIGURE 8.1: OVERARCHING BUSINESS PLANS



The following two key plans are subordinate to the AMP:

- *Mains Replacement Plan (MRP)* – which provides the basis and justification for the replacement of mains that have reached the end of their useful life and/or pose an unacceptable risk to public safety (see Attachment 8.2); and the
- *Capacity Management Plan (CMP)* – which describes the processes underpinning network design and analysis for ensuring that the Network has the capacity to deliver gas at sufficient pressure and quality to meet the forecast demand for services (see Attachment 8.3).

In addition to these documents, there is the Information Technology Plan (provided as Attachment 8.4), which provides the framework for the development and implementation of key business systems (such as applications, infrastructure and information) across AGN.

These plans govern the timing and approach to undertaking, among other things, investment/upgrade of critical business information systems, asset replacement and augmentation works that are necessary to ensure AGN's regulatory obligations are met. The plans aim to achieve an optimal balance between the key elements of asset management – service levels, reliability, cost and risk.

In addition to the above, AGN has prepared detailed Business Cases relating to specific capex requirements for the next AA period, which have been provided as Attachment 7.1 to this AAI.

8.4.2 Planning and Approval Process

AGN has robust planning and approval processes to ensure that its capex is prudent, efficient and consistent with good industry practice. As explained in Chapters 1 and 7, the forecasts and estimates used in this AA Proposal have been subject to a rigorous verification process, including that:

- forecasts are based on the considerable expertise of AGN and its contractor, APA Asset Management (APA);
- forecasts for projects have been based on robust Business Cases that have been subject to thorough review as to their compliance with the relevant requirements of the National Gas Law and NGR;
- where possible, forecasts have been based on the most recent actual information available, which information reflects revealed efficient expenditure/outcomes;
- all different options and relevant drivers of a particular forecast have been taken into account and explained in the Business Cases, including by providing any data used to derive a particular forecast;
- independent expert advice has been used in the preparation of forecast information, which advice has been attached to this AAI; and
- relevant industry stakeholders have been consulted, where appropriate, in deriving a forecast, plan and/or estimate.

Of particular relevance to the development of the capex forecasts, AGN also notes that:

- all capex, from design through to implementation, is required to pass through a series of internal delegations, including through the AGN Board depending on the materiality of the project;
- network modelling is undertaken to ensure there is sufficient capacity to meet demand and maintain minimum supply pressures in all parts of the Network;
- capital works are timed, wherever possible, to coincide with works undertaken by road authorities and other utilities in order to minimise the cost and disruption to the public;[50] and
- financial modelling is undertaken to ensure that network extensions and connections pass the economic test under Rule 79(2)(b) (a capital contribution is sought where the economic test is not met).

---

[50] The coordination of capital works was identified during the AGN stakeholder engagement program as a valued service that requires continued improvement by the business. As explained in Chapter 3, although customers indicated they would be willing to pay for the business to improve coordination of capital works, AGN has determined that this service can be delivered and improvements made wherever possible within existing resources.

AGN considers that the above governance arrangements ensure that actual and forecast capex satisfies the relevant requirements of the NGR, including that capex is prudent, efficient and consistent with good industry practice to achieve the lowest sustainable cost to consumers.

8.4.3 Cost Monitoring and Control Process

There are strict cost management processes between AGN and our contractor, APA, including in relation to the annual budgeting process and the ongoing monitoring of performance. Mr Ferguson, APA's General Manager – Networks, has described in his affidavit that the budget setting process involves significant debate over the appropriate unit rates and that there is continuous pressure to drive unit rates and costs down:

> *"At the first and subsequent meetings between APA and Envestra [AGN] referred to above, there is vigorous debate about the activities to be undertaken during the budget year, the volume of gas to be delivered, and the unit rates such as the cost per repair, the cost per metre for construction, the cost per correction of a leak etc. Envestra always heavily challenges any upward shift in rates and continuously presses for a reduction in rates. The Envestra representatives challenge how the rates are calculated or set and routinely require evidence for and justification of the opex [operating expenditure] and capex comprised in the budget. There is a constant tension in these meetings between APA's obligations under the OMA [Operating and Management Agreement] and making sure APA can deliver the required service on the one hand and Envestra's budgeting requirements and constant pressure to drive down costs on the other hand."* [51]

Once the budget is set, APA reports at the end of each month on all of the budgeted activities, with a focus on comparing actual performance against budget performance. The monthly reports are very detailed and require extensive explanation of reasons for any variation to budget. Mr Ferguson, in his affidavit, describes the cost monitoring and control process as a "*rigorous and often abrasive process with Envestra [AGN] relentlessly pursuing the driving down of costs and increased efficiencies.*"

This cost monitoring and control process, together with the planning and approval processes described in Section 8.4.2, ensures that capex incurred over the current AA period and forecast for the next AA period is prudent and efficient and consistent with good industry practice and the achievement of lowest sustainable costs.

8.4.4 Forecasting Lowest Sustainable Cost

As noted above, capex forecasts have been based on actual cost information wherever possible, which reflects revealed efficient expenditure incurred over the current AA period. This is appropriate given the regulatory and commercial incentives faced by AGN to reduce costs over time. The actual cost information could reflect internal costs incurred by the business or contractor costs derived through a competitive tender process.

In terms of the latter, in some cases our cost forecast has been informed through tender arrangements that apply on a prospective basis. For example, our mains replacement expenditure has been based on the outcomes of tendered or awarded contracts for areas where mains replacement will be taking place over the next AA period. This detailed tender information provides strong assurance that our capex forecast is consistent with the lowest sustainable costs (our tender process is described in Attachment 8.5).

Attachment 8.6 sets out the unit rates that have been used to derive the capex forecast set out in this chapter and related attachments. This includes their historical level, derivation and consideration of factors that impact on unit rates over the next AA period. Factors that may affect/alter unit rates over time include:

---

51 See affidavit of John Ferguson, which has been provided as confidential Attachment 2.3 to this AAI.

- *changes in the price of labour and materials* – AGN has applied a series of cost escalators prepared by industry experts to determine the extent that labour and materials costs are forecast to change over the next AA period (see Section 8.7); and

- *changes in work scope* – the scope of work undertaken under a contract may vary over time; for example, the type or mix of work to be undertaken over the next AA period might differ from that undertaken in the current AA period (such as laying mains or services in new estates versus established suburbs).[52]

The above process, including the reliance on actual cost information wherever possible, ensures that costs reflect a 'best forecast or estimate' that has been 'arrived at on a reasonable basis'. The approach taken to derive all cost forecasts has been explained in this AA Proposal.

8.4.5 Key Drivers of Forecast Capital Expenditure

AGN has also considered the key drivers of forecast capital expenditure, which include asset condition, demand growth and network reliability.

8.4.5.1 Asset Condition

The asset condition is determined from an engineering assessment of the physical and functional characteristics of an asset (or class of assets) to determine its suitability for continued service. Past reliability, likelihood of asset failure and consequence of asset failure are all considered as part of this assessment. Investment is required when the asset condition is such that the ability to maintain the reliability, safety and security of the Network is compromised.

AGN balances the risks and on going cost of maintenance against the cost of replacing assets, and where asset failure risks are high and reliability or public safety issues are present or likely, assets are replaced if other mitigation measures are not feasible or economic. A key component of capex over the current AA period and next AA period relates to mains replacement, which is not only fundamental to maintain and improve safety, but also to deliver improved capacity and reliability in respect of the services provided (see Section 8.5.1).

8.4.5.2 Demand Growth

AGN is required to ensure that the Network has the capacity to meet increasing demand (see Chapter 14 for forecast demand over the next AA period). Gas distribution networks are designed to accommodate peak-hourly demand. Unlike gas transmission pipelines, gas distribution networks contain relatively little gas storage capacity and therefore must be able to respond almost instantaneously to increases in demand.

A key driver of increases in peak demand is the increasing use of high-flow instantaneous gas hot water heaters, which are replacing the more traditional storage water heaters. Instantaneous heaters have higher peak demand requirements (despite using less gas overall). This means that parts of the Network that were previously reliable are increasingly at risk of being unable to provide gas at the appropriate pressure during peak periods, thereby requiring network augmentation.

8.4.5.3 Reliability

Section 38 of the South Australian Gas Regulations prescribes a minimum pressure requirement at the outlet of a gas meter.[53] AGN is also required by Section 2.2.1 of the Gas Distribution Code to use best

---

[52] This is an important consideration in the context of new connections. If, for example, relatively more connections are taking place in existing areas, the average cost per connection would increase. This is because connections associated with urban consolidation (i.e. in brownfield conditions) are more costly than those taking place in new estates (i.e. in greenfield conditions).

[53] The minimum pressure requirement is set at 1.0 kilopascal. A kilopascal is a unit of pressure (one kilopascal equals 1,000 pascals).

endeavours to maintain the capability of the distribution system, which means that AGN must ensure sufficient gas pressure is maintained throughout the Network. Maintaining sufficient gas pressure is a key part of ensuring the safe and reliable supply of natural gas.

Where it is forecast that the gas pressure in a part of the Network will fall below minimum design levels, augmentation works have been identified and scheduled.

8.4.5.4 Summary

The three factors identified above are factored into AGN's AMP for the Network (Attachment 8.1). As noted earlier, the AMP documents the interrelationship of a number of technical and operational plans and how these plans are used to drive asset management strategies and actions to ensure the safe and reliable supply of gas in line with the:

- *regulatory obligations* – particularly the requirements of Rule 79 of the NGR;
- *effective risk management* – as per the policy and procedures set out in the AMP and its subordinate plans;
- *lowest sustainable lifecycle costs* – such that costs over the useful life of the asset are minimised; and
- *good industry practice* – as the procedures and processes adopted by AGN conform with industry best practice.

8.5 Forecast Capital Expenditure

This section sets out AGN's forecast capex over the next AA period. This includes a discussion of the scope of the proposed works, key cost drivers and forecast expenditure (expressed in 2014/15 dollar terms and before the application of escalators and overheads). The more detailed reasoning for the forecast capex is set out in the various overarching plans described in Section 8.4.1 and the related Business Cases provided in Attachment 7.1.

8.5.1 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 MRP, which sets out the strategy for the replacement of ageing/deteriorating mains on the Network. Not surprisingly, the delivery of our MRP is one of the key elements of our AA Proposal, accounting for 60% of the total forecast capex. The three components of our MRP are the replacement of:

1. all remaining low pressure cast iron (CI) and unprotected steel (UPS) mains;
2. the remaining medium pressure 'Class 250' high-density polyethylene (HDPE) mains, and
3. the high pressure 'Class 575' HDPE mains identified as having the highest risk.

The latter two components are jointly referred to as our HDPE mains replacement program.

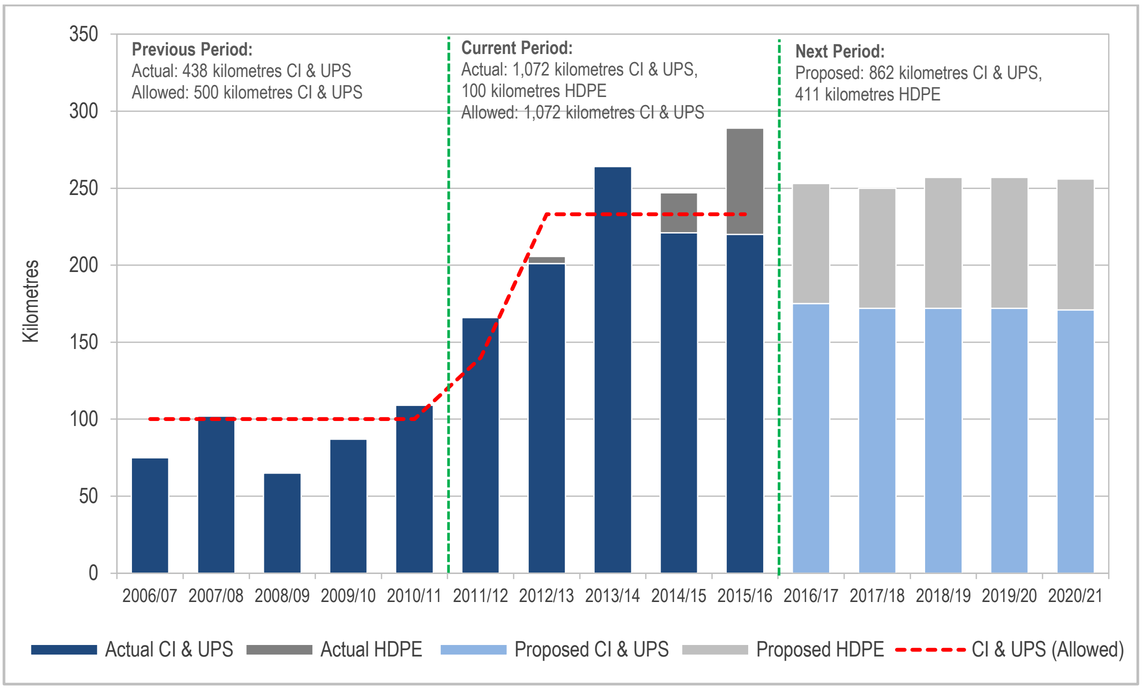
This section provides an overview of our performance against the mains replacement program in the current AA period before describing in more detail the above three elements of our MRP. The MRP provided as Attachment 8.2 provides a detailed discussion of our mains replacement program.

8.5.1.1 Delivery of our Mains Replacement Plan

AGN has demonstrated a strong commitment to its MRP. In the current AA period, AGN is expecting to replace 1,172 kilometres of mains, which is 100 kilometres above the benchmarks set for the current AA period (see Figure 8.2). The additional 100 kilometres reflects the commencement of the HDPE mains replacement program, which was not included in the capex benchmarks set by the AER for the current AA period.

Figure 8.2 also shows the changing composition of our mains replacement driven by the commencement of the HDPE replacement program (reflected by the grey shading in the figure). The proportion of HDPE replacement (in terms of volume) is forecast to increase from 9% of total mains replacement over the current AA period to 32% over the next AA period. The HDPE replacement program will account for 100% of our mains replacement once the CI and UPS replacement program has been completed in 2020/21.

FIGURE 8.2: MAINS REPLACEMENT 2006/07 TO 2020/21



The key benefits derived from the mains replacement program over the current AA period include a:

- 50% reduction in CI and UPS mains and service leaks;
- 36% reduction in CI mains breaks;
- 60% reduction in customer reported supply complaints related to water in mains; and
- 34% reduction (or 730 terajoules) in unaccounted for gas (UAFG).

With regard to the latter, AGN estimates that actual UAFG volumes will further reduce by the end of the current AA period.

8.5.1.2 Cast Iron and Unprotected Steel Mains Replacement Program

AGN remains committed to completing the CI and UPS mains replacement program that was endorsed by the AER in its Final Decision for the current AA period. In its 2011 Draft Decision for the Network, which decision was carried through to the Final Decision, the AER stated that:

> *"…Envestra [AGN] has established a requirement for the replacement of its cast iron and unprotected steel mains to maintain and improve safety of services and to maintain the integrity of services in accordance with the NGR. The AER has reached this conclusion for a*

> *number of reasons. Most importantly, the AER has concerns about the safety risk posed through the leakage of gas from Envestra's distribution network."*[54]

In making this decision, the AER had regard to the endorsement of our mains replacement program by its technical expert as well as submissions from the Office of the Technical Regulator of South Australia (OTR), the Essential Services Commission of South Australia and the Government of South Australia. The AER at the time did express concern that approving the mains replacement plan, which provided for an acceleration of replacement rates, presented a risk to consumers that AGN would not meet the targets.

As already noted, AGN has, however, delivered the volume of CI and UPS mains replacement volumes approved by the AER for the current AA period (this is also the case in our other regulated networks such as in Victoria). AGN is committed to completing this program and remains on track to meet its objective of replacing all of these mains by 2020/21. This AA proposal provides for 862 kilometres of CI and UPS mains to be replaced over the next AA period, which would eliminate all CI and UPS on the Network.

This program is necessary to ensure the ongoing safe and reliable supply of natural gas to our South Australian consumers, including by:

- reducing the risks to both public and employee safety and property damage associated with natural gas leakage from the Network;
- increasing network capacity by replacing low pressure with high pressure mains (which facilitates new customer connections and the ongoing shift towards instantaneous natural gas hot water appliances); and
- improving network reliability by reducing the incidence of unplanned outages on the Network.

As noted above, the CI and UPS mains replacement program has delivered key safety and reliability benefits to consumers over the current AA period. The completion of this program will ensure this performance is maintained over the next AA period.

TABLE 8.1: CI AND UPS MAINS REPLACEMENT CAPEX FORECAST

$2014/15 million	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Total	48.3	47.3	44.7	44.1	39.6	**224.0**

Note: Totals may not add due to rounding.

8.5.1.3 HDPE Mains Replacement Program

AGN has also commenced and will continue with the replacement of parts of the HDPE network over the next AA period.

This is partly in response to failures relating to old HDPE mains. AGN has allocated considerable resources to understanding the behaviour of this material and to developing appropriate integrity management strategies to manage this issue going forward (this is explained in more detail in our Mains Replacement Plan, which is set out in Attachment 8.2 to this AAI).

Our analysis has shown that the early generation HDPE mains originally used for natural gas reticulation are approaching the end of their useful life and are prone to failure under certain conditions. While the historic frequency of these types of failures is low, prudent asset management dictates that a number of measures need to be undertaken, and consequently the following actions are being pursued:

---

54 AER 2011, "*Envestra Ltd: Access Arrangement Proposal for the SA Gas Network, 1 July 2011 – 30 June 2016*", Draft Decision, February 2011, pg. 28.

1. replace all medium pressure Class 250 HDPE mains, which is the oldest HDPE in the Network, by 2020/21;
2. replace high pressure Class 575 HDPE mains in a number of locations;
3. research and develop pipe camera technology to identify defects, in order to better target replacement and repairs; and
4. develop a reliability forecast model to predict the remaining life of Class 575 HDPE, so that risk mitigation strategies, including replacement, can be optimised.

The first three actions relate to capex while the last action relates to operating expenditure (opex). All four actions, particularly the replacement of the HDPE mains, are a key component in maintaining the safety and reliability of the Network. Importantly, AGN has already commenced the above actions to manage the risks associated with the HDPE mains over the current AA period. The Class 250 and Class 575 mains replacement programs proposed for the next AA period are set out in Table 8.2.

TABLE 8.2: HDPE MAINS REPLACEMENT CAPEX FORECAST

$2014/15 million	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Total	23.8	23.8	26.0	28.8	28.8	**131.2**

Note: Totals may not add due to rounding.

8.5.1.4 Consistency with the National Gas Rules

The forecast expenditure on the mains replacement program is necessary in order to:

- *maintain or improve the safety of services (Rule 79(2)(c)(i))* – the capex is the key driver for maintaining public safely:
  - the MRP has and will continue to reduce the incidence of gas leaks on the Network, which in turn improves public and employee safety (including lowering the potential for property damage);
  - as noted, throughout this AAI, maintaining the safe and reliable supply of natural gas is the key driver of business performance;
- *maintain the integrity of services (Rule 79(2)(c)(ii))* – the capex is necessary to maintain the integrity of services, as it will result in the avoidance of:
  - outages due to water ingress;
  - supply loss arising from leak repair works; and
  - poor pressure (or loss of supply) at a consumer site due to peak loading on low pressure mains.
- *comply with a regulatory obligation (Rule 79(2)(c)(iii))* – the capex is necessary to comply with all relevant regulatory obligations relating the supply of natural gas on the Network, particularly Part 1 of the *South Australian Gas Act 1997*, which requires AGN to:

  "… promote the establishment and maintenance of a safe and efficient system of gas distribution and supply…"

- *maintain AGN's capacity to meet levels of demand for services (Rule79(2)(c)(iv))* – the CI and UPS program results in the replacement of low pressure with high pressure mains, which facilitates new customer connections and the ongoing shift towards instantaneous gas hot water appliances (which appliances require greater network capacity relative to the traditional storage hot water systems).

The key elements of the above, however, relate to the requirements for AGN to maintain and improve the safety of services (Rule 79(2)(c)(i)) and comply with a regulatory obligation (Rule 79(2)(c)(iii)).

8.5.2 Information Technology

A gas distributor deals with substantial amounts of information on a daily basis, which includes information relating to customer connections and disconnections, laying and repairing mains, managing gas repairs as well as meter reading and billing information. The volume of activity requires ongoing investment in systems that link together to allow the high volumes of activities to flow from one system to the other and ensure full functionality to manage critical business process and satisfy retail market rules.

AGN has initiated a national program of work to replace old state-based IT systems that have been in place for over ten years, and as such, are no longer supported by the appropriate vendor nor able to be updated to prevent system security vulnerabilities. New enterprise equivalents servicing all five Australian jurisdictions in which AGN operates are being implemented in order to achieve the lowest sustainable costs by maximising the economies of scale available to AGN. Considerable progress has been made towards the nationalisation of the IT systems and infrastructure over the current AA period.

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 core business systems;
- enable the effective and efficient delivery of Reference Services (as defined in Chapter 6); 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, increase the risk of non-compliance with relevant regulatory obligations (and legislation more generally), lead to customer and business interruptions, potential public safety issues and the corresponding adverse financial and reputational consequences. Investment in IT accounts for around 10% of total forecast capex over the next AA period.

This section outlines the key components of the IT Plan for the next AA period. The IT Plan (Attachment 8.4) and related Business Cases (Attachment 7.1) provides a more detailed discussion of our proposed IT investments.

8.5.2.1 Applications Renewal (Business Case SA57)

AGN is proposing to implement an application upgrade roadmap in order to ensure that application systems for the Metering and Billing System, Telemetry System, Geospatial Information System (GIS) and Enterprise Asset Management System are updated. This project is required to perform upgrades on existing IT assets and does not involve their replacement. This upgrade program will:

- ensure upgraded applications continue to provide required integrated functionality to support business processes;
- manage alignment with other co-existing applications;
- ensure validity of support requirements with technology vendors;
- introduce appropriate new functionality across the business; and
- improve software performance and efficiency.

8.5.2.2 Geospatial Information System (Business Case SA58)

AGN intends to upgrade its current GIS, which manages all geographic data associated with the Network (that is, the GIS maps the location of network infrastructure). The key objectives from this project are to:

- reduce business risk resulting from an unsupported version of a critical business management application;
- improve the functionality and upgrade path of the GIS application by removing historical customised functionality;
- leverage benefits from integrating the GIS into an enterprise IT system architecture; and
- implement prudent and efficient end-to-end business processes to ensure ongoing accuracy of GIS data.

This project will mitigate a significant business risk associated with an unsupported GIS application and integrate the GIS into the broader Enterprise Asset Management suite of IT applications.

8.5.2.3 Mobility IT (Business Case SA59)

The purpose of this project is to provide for the mobile integration of resources across the Network. The objectives are to:

- enhance the mobile communications platform to enable field mobility within the workforce (i.e. to send real time information to field workers);
- integrate the enhanced mobile communications into the Enterprise Asset Management System (Maximo) and GIS; and
- implement prudent and efficient end-to-end business processes that automate enterprise asset management and GIS functionality through mobility.

This project intends to improve service delivery to customers through the integration and application of enterprise-wide asset management and geospatial information, to automate current paper-based and manual processes and enable the field work force to deliver high quality and timely services through the use of mobile devices and integrated processes, consistent with the expectations of consumers and stakeholders more generally.

8.5.2.4 Business Intelligence (Business Case SA60)

This project involves the implementation of a 'Business Intelligence' toolset, which will provide improved information and reporting across AGN by utilising the data from the disparate IT applications that are used within the business. The objectives of this project are to:

- implement a business intelligence toolset that allows consolidated views of disparate sets of data from multiple IT applications;
- drive improved decision making through additional access to information;
- streamline reporting through standardised reporting tools;
- provide integration into other enterprise business applications to provide ease of publishing/reporting information; and
- implement prudent and efficient end-to-end business processes to maintain and improve data quality.

This project will provide a toolset that will improve data quality, streamline reporting effort and allow greater access to information for optimised decision making.

8.5.2.5 SCADA IT (Business Case SA62)

The Supervisory Control and Data Acquisition (SCADA)[55] and Historian[56] system in South Australia has limited remaining capacity, necessitating its modification and/or upgrade prior to 2017. The key objectives of this project include the:

- upgrade of the ClearSCADA system to the national ClearSCADA standard; and
- replacement of the South Australian Historian system with a new South Australian-specific module on the Networks Interval Metering Data System application that runs on the existing National Enterprise Historian platform.

8.5.2.6 Development of Digital Capabilities (Business Case SA84)

The purpose of this project is to develop of a range of digital capabilities aimed at delivering an improved customer service experience that is in line with the delivery of services by other distributors (and businesses more generally). AGN, based on expert advice, is proposing this project be completed in three key phases:

1. year 1 – develop key project objectives/requirements in order to develop the project scope;
2. years 1 to 2 – develop the digital platform that is consistent with stakeholder values and complying with our regulatory obligations; and
3. year 3 onwards – implementation of the digital platform, including providing for the digitisation of key customer transactions across the business (such as automating the customer connection process).

During our stakeholder engagement program (see Chapter 3), stakeholders indicated that they want more communication from AGN, including through digital channels (see Attachment 3.9). Deloitte, which was engaged by AGN to report on the feedback received during our stakeholder engagement program, noted in its report that:

> *"Customers generally prefer digital channels for greater accessibility and convenience. They also commented that digital channels are cost effective and reduce paper waste, yet the call centre and traditional written communication (letters) were also ranked in the top five preferred communication channels.*
>
> *Customers expressed a desire for more communication from AGN and provided guidance on when they prefer immediate 'real-time' channels versus more traditional communications. Specifically, customers are seeking more personalised communications regarding issues affecting their supply, property or local area such as SMS, email and website notification for unplanned outages.*
>
> *For planned works, such as outages, meter replacements and mains replacements there is*

55 The SCADA system is a communication channel that enables the remote control of the network and remote data collection.

56 The Historian system collects and stores the metering data from the SCADA system, which is used to make operational decisions.

a preference for email as customers like to keep a record of these notices (traditional mail was also favoured for this reason)."[57]

This project is consistent with stakeholder values through the development of enhanced digital capabilities across the business.

8.5.2.7 Remote Meter Reading (Business Case SA64)

AGN plans to trial an Automated Meter Reading (AMR) capability on a small number of gas meters that cannot be accessed (for example, because the meter is behind a locked gate). To assess the feasibility of this technology, AGN plans to undertake the trial in both new and existing areas. This trial is expected to provide sufficient information for AGN to assess the feasibility of network wide implementation of AMR, which if successful would result in cost savings and further efficiencies over time.

During our stakeholder engagement program (Chapter 3) we tested with customers if they would be willing to pay for the roll-out of remote meter reading devices to all new and replacement meters. Only 44% of those tested indicated they would be willing to pay for this initiative, although customers did indicate they were supportive of AGN investigating ways to improve service and increase efficiency.

In light of the stakeholder feedback, AGN redesigned the Remote Meter Reading Business Case to consist of a trial roll-out to inaccessible meters, as opposed to a roll-out on all new and replacement meters. This will allow AGN to increase meter-read efficiency (to those meters in the trial) whilst also collecting valuable information on the feasibility of a wider roll-out program, which can then be used to inform more detailed stakeholder engagement on the program.

8.5.2.8 Industry Change Projects (Business Case SA65)

This project accounts for industry initiated change projects that will arise over the next AA period and will impact on the AGN asset management and metering and billing systems. These projects are initiated by market participants, including the Australian Energy Market Operator, retailers and distributors, to address issues that arise in the retail gas market. For example, AGN was required to install a 'retailer of last resort' system in the current AA period, the cost of which was not incorporated in AGN's regulatory allowance.

At the time of preparing this AA Proposal, there are 21 industry issues in progress and a further 30 issues pending review. The costs for such activities are not allowed for anywhere else and are required to be spent by AGN to meet its regulatory obligations on an ongoing basis.

8.5.2.9 Infrastructure Upgrades (Business Case SA82)

This infrastructure renewal project relates to the upgrade of two key pieces of AGN infrastructure: desktop infrastructure and telephony infrastructure. The objective is to provide for:

- a modern, supported and resilient communication and collaboration platform;
- integrated and enhanced communication channels across the business; and
- capability to leverage future business and communication integrations.

8.5.2.10 Consistency with the National Gas Rules

Forecast expenditure on the IT program is necessary in order to:

[57] Deloitte 2015, "*Australian Gas Networks Stakeholder Insights Report*", February 2015, pg. 16. Provided as Attachment 3.9 to this AAI.

- *maintain or improve the safety of services (Rule 79(2)(c)(i))* – for example, the current GIS system is in critical need of an upgrade and without this upgrade, there is a significant risk that our GIS system may cease being operational, leaving AGN without the capability of locating assets and/or providing information to third parties about the location of our assets;

- *maintain the integrity of services (Rule 79(2)(c)(ii))* – AGN would not be able to deliver Reference Services without the investment in IT infrastructure; consequently, the continual upgrade and renewal of critical IT applications and infrastructure, as well as investment in new IT technologies, is vital in order to maintain the ongoing integrity of services.

- *comply with regulatory obligations (Rule 79(2)(c)(iii)* – for example, compliance with the Retail Market Procedures would not be possible without appropriate IT systems and these procedures change over time as the market evolves, so continual investment in IT systems and technologies is necessary to maintain compliance with these regulatory obligations on an ongoing basis.

8.5.2.11 Information Technology Expenditure Summary

The following table sets out the forecast capex for all IT related capex over the next AA period. Further details of these IT projects, including forecast costs, are set out in the Business Cases that were referenced in this section.

TABLE 8.3 INFORMATION TECHNOLOGY CAPEX FORECAST

$2014/15 million	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Applications Renewal (SA57)	3.8	2.6	3.8	2.6	4.8	**17.7**
Geospatial Information System (SA58)	2.6	8.6	3.8	0.0	0.0	**15.0**
Mobility IT (SA59)	0.0	1.9	2.1	2.8	2.2	**9.0**
Business Intelligence (SA60)	0.0	2.0	3.9	2.6	0.1	**8.6**
SCADA IT (SA62)	2.2	1.2	0.0	0.0	0.0	**3.3**
Development of Digital Capabilities (SA84)	0.0	0.4	0.4	0.0	0.0	**0.9**
Remote Meter Reading (SA64)	1.5	0.6	0.1	0.1	0.1	**2.5**
Industry Change Projects (SA65)	0.4	0.4	0.4	0.4	0.4	**1.8**
Infrastructure Upgrades (SA82)	0.5	0.5	0.0	0.0	0.0	**1.0**
Total	**11.0**	**18.1**	**14.5**	**8.5**	**7.6**	**59.7**

Note: Totals may not add due to rounding.

8.5.3 Growth Assets

The key driver of growth capex is new connections to the Network. This category of expenditure includes:

- *general mains* – which includes the extension of mains for the provision of gas to new customers, which range from large projects required to provide gas to new housing estates to small mains extensions in existing gas areas required to connect a single residential customer:
  - the forecast cost is based on an average length of main (based on an historical average) required to extend the Network on a 'per customer' basis, taking into account both new housing estate (greenfield) sites and established suburb (brownfields) sites;

- *inlet services* – which includes the pipework that runs from the gas main to the gas meter, which can vary in length and size depending on the gas demand of the customer:

   - the cost per service is affected by the terrain and environmental characteristics of the site being connected (for example, it is easier and cheaper to connect gas to a new home than to an existing home or to an existing building in the central business district); and

- *meters* – which includes the cost of installing the meter and gas regulator and the subsequent commissioning process to ensure that natural gas is supplied in a safe manner in accordance with our legislative obligations.

The growth category also includes any forecast capex relating to large new developments or extensions to the Network.

AGN has included forecast capex for a proposed extension in Two Wells in the next AA period. AGN has been working with developers and the District Council of Mallala regarding this extension and expects that an additional 3,200 customers will connect to the Network as a result of this extension. This extension will lower costs to existing customers by spreading the largely fixed costs of operating the Network across a larger customer base, thereby lowering the costs per customer.

Capex for growth assets has been forecast by applying forecast unit rates to the number of new connections forecast by Core Energy to occur over the next AA period (except for the Two Wells project, where AGN has developed a bottom-up cost estimate). The derivation of the unit rates are set out in Attachment 8.6 and forecast cost relating to the Two Wells project are provided in Business Case SA24 (contained in Attachment 7.1). Table 8.4 sets out the forecast total growth capex over the next AA period.

TABLE 8.4: GROWTH CAPEX FORECAST

$2014/15 million	2016/17	2017/18	2018/19	2019/20	2020/21	Total
General Growth	18.8	18.8	19.4	19.9	19.2	**96.1**
Two Wells (Business Case SA24)	0.0	0.0	0.0	5.0	0.0	**5.0**
Total	**18.8**	**18.8**	**19.4**	**24.9**	**19.2**	**101.1**

Note: Totals may not add due to rounding.

8.5.3.1 Consistency with the National Gas Rules

The revenue recovered from new customers connected to the network is greater than the costs associated with that new customer connection (as required by Rule 79(2)(b)). AGN undertakes economic modelling to ensure that the economic test is met, with customer contributions requested where the economic test is not met. AGN notes that stakeholders indicated support for expanding the Network where there is a clear benefit to existing customers.

8.5.4 Meter Replacement

AGN is required to periodically change gas meters in order to test them for accuracy. These periodical meter changes (PMCs) take place at intervals of around 10 to 15 years, as authorised by the South Australian Office of the Technical Regulator (OTR). This continuous changeover and testing program ensures that each gas meter continues to operate within prescribed tolerances. These obligations are set out in the Gas Measurement Management Plan, which is submitted annually to the OTR for approval (see Attachment 8.7).

The number of meters requiring changeover is reflective of the age and type of meters in service. As these factors are well documented and tracked by our works management system, the forecast quantity has a high degree of certainty. The cost of this activity is also well established, with this cost dependent upon the following three factors:

- the cost of new and refurbished meters;

- the mix of new and refurbished meters (AGN refurbishes and recycles meters wherever possible in order to achieve lowest sustainable costs); and

- the number of required meter changes – there is a fixed cost base for this activity that is spread across the number of meters changed.

The OTR undertakes audits of AGN's meter replacement activities, including meter testing and refurbishment activities and processes. AGN also reports to the OTR our compliance with the Gas Measurement Management Plan. This oversight provides an additional level of assurance regarding the prudent and efficient delivery of our meter replacement activities. Table 8.5 summarises the forecast meter replacement costs.

TABLE 8.5 METER REPLACEMENT CAPEX FORECAST

$2014/15 million	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Domestic Meters	3.9	3.6	3.2	2.5	1.7	**14.9**
Industrial and Commercial Meters	0.4	0.4	0.5	0.4	0.6	**2.2**
Total	**4.2**	**4.0**	**3.7**	**2.9**	**2.3**	**17.1**

Note: Totals may not add due to rounding.

8.5.4.1 Consistency with the National Gas Rules

Forecast expenditure on the meter replacement program is necessary to meet AGN's regulatory obligations under the Gas Measurement Management Plan (as approved by the OTR) and the Gas Metering Code (Rule 79(2)(c)(iii)).

8.5.5 Augmentation

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

- reinforcement of those sections of the Network where gas pressure is forecast to fall to an unacceptable level and each reinforcement is designed to maintain reliability and ensure the pressure delivered complies with our regulatory obligations;

- augmentation to ensure that the Network is capable of continuing to meet the demand for services, particularly in areas of high growth;

- augmentation to ensure the availability of high pressure gas to support the systematic and planned replacement of low pressure mains; and

- protection of the Network from over-pressurisation, which can occur if key pressure regulator facilities fail to operate as designed.

AGN's CMP (Attachment 8.3) and related Business Cases provide detailed information of the following proposed augmentation projects:

- *Southern Transmission Pipeline (Business Case SA21)* – this project involves the replacement of over five kilometres of transmission pressure pipeline within the southern part of the Network, where integrity issues with this section of pipeline mean that gas supply to over 20,000 customers could be affected if any one of a number of corrosion defects were to cause a sudden failure;

- *Pitting Issues Under Sleeves (Business Case SA21a)* – this project rectifies the issue of corrosion on field-welded joints due to the dis-bonding of heat-shrink sleeves. The project incorporates undertaking 52 exploratory excavations per year to investigate and rectify corrosion on transmission pipelines and is required to ensure the ongoing safety of the Network;

- *Murray Bridge Augmentation (Business Case SA71)* – this project involves the construction of a two-kilometre steel transmission main in Murray Bridge and connecting the existing Murray Bridge regulator station to this new transmission main;

- *Overpressure Protection (Business Case SA19*) – this project involves the installation of an over-pressure shut-off system at 45 transmission pressure regulator stations within the distribution network and to replace obsolete pressure regulating valves at 29 of these stations;

- *Southern Networks Augmentation (Business Case SA15)* – this project is to augment the high pressure network in response to forecast customer growth in Noarlunga, Aldinga and McLaren Vale;

- *Virginia High Pressure Augmentation (Business Case SA17)* – this project is required to ensure adequate supply pressure in the locality of Virginia, and involves installing 1.4 kilometres of mains; and

- *Reactive Augmentation (Business Case SA14)* – this project reduces the number of network capacity issues that occur unexpectedly from time to time by augmenting sections of the Network in response to ad-hoc low pressure problems.

TABLE 8.6: AUGMENTATION CAPEX FORECAST

$2014/15 million	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Southern Transmission Pipeline (SA21)	0.4	7.1	0.0	0.0	0.0	**7.5**
Pitting Issues Under Sleeves (SA21a)	0.7	0.7	0.7	0.7	0.7	**3.3**
Murray Bridge Augmentation (SA71)	0.0	0.5	2.5	0.0	0.0	**3.0**
Overpressure Protection (SA19)	0.4	0.4	0.3	0.3	0.2	**1.6**
Southern Networks Augmentation (SA15)	0.0	0.0	0.0	1.3	0.0	**1.3**
Virginia High Pressure Augmentation (SA17)	0.0	0.0	0.8	0.0	0.0	**0.8**
Reactive Augmentation (SA14)	0.2	0.1	0.1	0.1	0.0	**0.4**
Total	**1.6**	**8.8**	**4.3**	**2.3**	**0.8**	**17.9**

Note: Totals may not add due to rounding.

AGN notes that the forecast augmentation capex is less than half of that incurred in the current AA period. This is because, as mains replacement takes place, the proportion of the Network served by high pressure mains increases, thereby increasing the resilience of the Network. Given this, the forecast cost of augmentation work decreases over the next AA period as a result of the mains replacement program.

8.5.5.1 Consistency with the National Gas Rules

Forecast augmentation capex is necessary in order to:

- *maintain or improve the safety of services (Rule 79(2)(c)(i))* – if the above augmentation projects are not undertaken, gas pressure to consumers will be comprised:
  - where insufficient gas pressure is available to fuel appliances, there is a risk of malfunction or flame failure, the consequences of which could be an explosion, or asphyxiation of persons in the vicinity of the appliance;

- *maintain the integrity of services (Rule 79(2)(c)(ii))* – the augmentation projects are required to maintain sufficient pressure to supply existing customers and to supply new customers;

- *comply with a regulatory obligation (Gas Regulation 11(1)(c)(i))* – the augmentation projects are required to maintain the required minimum pressure at the consumer's meter as per Gas Regulation 11(1)(c)(i)) and to operate the Network in accordance with good industry practice (Gas Distribution Licence clause 5.1); and

- *maintain the service provider's capacity to meet levels of demand (Rule 79(2)(c)(iv))* – the augmentation projects are required in order to ensure that the Network has sufficient capacity to meet the forecast demand.

8.5.6 Other Forecast Capital Expenditures

Mains replacement, IT, growth, meter replacement and augmentation accounts for over 90% of the total forecast capex for the next AA period. This section outlines all remaining capex and references the appropriate Business Case where further information is provided.

8.5.6.1 Regulators and Valves

Regulator stations and valves are located throughout the Network and play a critical role in the regulation of gas pressures and flows. AGN has forecast the following capex to address the various operational needs relating to these assets:

- *Below Ground Regulators (Business Case SA22)* – this project is a continuation of the current program of work to replace 66 below-ground brick chamber regulators that have reached the end of their useful lives; AGN intends to replace an additional 15 regulators in the next AA period;
- *Relocation of Meters (Business Case SA75)* – which involves the relocation of vulnerable meter installations:
  - over time, changes in circumstances have resulted in some meter installations being located in unsafe locations (for example, vulnerable to impact by vehicles);
  - relocation of these assets is therefore required to maintain the safety and integrity of these assets.
- *Industrial and Commercial (I&C) Meter Sets (Business Case SA33)* – which involves the upgrade of a number of I&C meter sets to current standards, in particular, the requirement for minimum separation distances from building openings and electrical equipment to reduce the possibility of gas explosions;
- *Industrial and Commercial (I&C) Meter Set Refurbishment (Business Case SA08)* – this involves grit blasting and painting of elevated pressure (I&C) meter sets to prevent the continued spread of corrosion on these assets, thereby ensuring the ongoing safe operation of the Network;
- *Non-compliant Domestic Regulators (Business Case SA45)* – which is a continuation of a current program that has seen around 3,000 regulators replaced at domestic meter installations in the current AA period, around 9,600 regulators are expected to be replaced in the next AA period;
- *Transmission Valves (Business Case SA70)* – which involves the replacement of six inoperable valves in the transmission pressure parts of the Network that, due to their age and location, are scheduled for replacement and relocation in order to maintain Network security and safety;
- *Unserviceable Transmission Pressure Regulator Components (Business Case SA34)* – which involves the replacement of unserviceable over-pressure shut-off valves and transmission pressure (TP) regulators that are over 40 years old (as spare parts no longer available); and
- *Valve Corrosion Protection (Business Case SA09)* – which involves the in-situ grit blasting and coating of 80 critical isolation valves located in underground valve pits that, if left unchecked, could cause a significant risk to the safe and reliable supply of natural gas on the Network.

Table 8.7 sets out the forecast capex arising from each of the above projects.

TABLE 8.7: REGULATORS AND VALVES CAPEX FORECAST

$2014/15 million	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Below Ground Regulators (SA22)	1.0	1.0	1.0	1.0	1.0	**5.0**
Relocation of Meters (SA75)	0.5	0.5	0.5	0.5	0.5	**2.3**
I&C Meter Sets (SA33)	0.4	0.4	0.4	0.4	0.3	**2.0**
I&C Meter Set Refurbishment (SA08)	0.4	0.4	0.4	0.4	0.4	**1.8**
Non-compliant Domestic Regulators (SA45)	0.2	0.2	0.2	0.2	0.2	**0.9**
Transmission Valves (SA70)	0.0	0.1	0.3	0.3	0.3	**0.9**
Unserviceable Transmission Pressure Regulator Components (SA34)	0.1	0.1	0.1	0.1	0.0	**0.4**
Valve Corrosion Protection (SA09)	0.1	0.1	0.1	0.1	0.1	**0.3**
Total	**2.6**	**2.6**	**2.8**	**2.8**	**2.7**	**13.6**

Note: Totals may not add due to rounding.

Consistency with the National Gas Rules

The forecast expenditure on regulators and valves is necessary to:

- *maintain and improve the safety of services (Rule 79(2)(c)(i))* – for example, if the below-ground regulators that have been identified as being at the end of their useful lives are not replaced, then they will pose an occupational health and safety hazard for maintenance personnel; and
- *maintain the integrity of services (Rule 79(2)(c)(ii))* – for example, if a regulator fails (or a valve becomes inoperable) it can result in a loss of supply of services.

8.5.6.2 Telemetry

AGN relies on telemetry or SCADA systems 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. AGN is proposing to:

- install new telemeters in order to better monitor pressure at transmission pressure regulator locations and at network extremity points; and
- upgrade and replace modem equipment and flow correctors at demand customer sites.

Table 8.8 sets out the forecast capex relating to this project for the next AA period (further detail on this project is provided in Business Case SA01).

TABLE 8.8: TELEMETRY CAPEX FORECAST

$2014/15 million	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Total	0.3	0.2	0.2	0.2	0.1	**1.1**

Note: Totals may not add due to rounding.

Consistency with the National Gas Rules

These works will reduce the risk of major supply interruption (Rule 79(2)(c)(i)) and provide more accurate, reliable and timely pressure data to better inform network capacity models (Rule 79(2)(c)(ii)).

8.5.6.3 Other Distribution System Capex

There are numerous other items of distribution system capex that do not fall into the aforementioned categories, but are required to support the delivery of Reference Services. These costs are captured within the 'Other Distribution System Capex' category. The project justification, including an assessment against the NGR and our stakeholder engagement program[58], is provided in the relevant Business Cases that are provided in Attachment 7.1 to the AAI. These projects are summarised as follows:

- *HDPE Live Camera Inspection and Repairs (Business Case SA52)* – this project allows for camera field crews to use cameras to inspect the HDPE network using a cable camera inserted into live gas mains to locate and rectify points of likely failure; this is a unique and cost-effective solution AGN is currently developing in order to defer the costly replacement of the HDPE network and is necessary to ensure the continued safe operation of the Network;

- *Fire Safety Valves (Business Case SA31)* – this project includes the continuation of a project to install fire safety valves at consumer premises located within high bushfire risk areas, on gas meters located near brush fences, all new domestic consumer sites and to retrofit all existing consumers' gas meters when the meters are due for renewal as part of the PMC process; this project received the strongest support from our stakeholder engagement program;

- *Replacement of Exposed Plastic Service Pipe (Business Case SA28)* – this is a continuation of an existing project, which involves the replacement of parts of residential polyethylene service pipes that are located above ground; this project received strong support from our stakeholder engagement program;

- *Sleeved Railway Crossings (Business Case SA10)* – this project provides for the excavation, inspection and repair of 55 transmission pressure sleeved crossings within the Network, repair is necessary due to the compromised cathodic protection on these crossings, which are located within road and rail corridors;

- *Replacement Associated with Non-Compliant Meter Installations (Business Case SA32)* – this project rectifies the non-compliant location of gas meters in line with Australian Standard AS4645:
  - as a legacy of past practices and/or building modifications by property owners, there are meters with non-vented regulators located inside buildings;
  - these meters pose the risk of gas escape from a venting regulator, resulting in gas accumulation in an enclosed space, potentially leading to a gas explosion and/or major damage to property;
  - this project received moderate support from our stakeholder engagement program;

- *Distribution Trunk Mains Direct Current Voltage Gradient (DCVG) Survey and Dig-Ups (Business Case SA49)* – this project includes the DCVG survey of a steel distribution trunk main that has not been previously surveyed:
  - it is proposed to survey this main due to findings of significant corrosion on similar trunk mains;
  - the project provides for 85 defect excavations and coating repairs;
  - if left unchecked, this corrosion could result in major gas escapes posing a significant risk to personal injury and third party damage;

[58] During the stakeholder engagement program, consumers indicated that they valued and were willing to pay for a number of initiatives. For a full discussion on the outcomes of the stakeholder engagement program and how they relate to each of the projects, please refer to the individual Business Cases.

- *Transmission Pipelines Dig-Up (Business Case SA36)* – this is a project to excavate transmission pipelines that have been found to be subject to significant corrosion; the level of corrosion present on these pipes could result in a major gas escape if not identified and effectively remediated;

- *Replacement of Insulation Flanges on Transmission Mains (Business Case SA37)* – this project involves the removal and replacement of a number of insulating flanged joints on the TP mains that are at the end of their useful life and are at risk of leaking;

- *Corrosion Transmission Pipeline Mains M36 (Business Case SA53)* – this project incorporates the excavation and repair of coating defects and pipeline corrosion on the 'M36' pipeline, which is 47 years old, to ensure the ongoing safety of the Network; and

- *Installation of Corrosion Protection Units (Business Case SA06)* – this project is a continuation of a current program of work to replace a system of sacrificial anodes with telemetered impressed current corrosion protection units in the coated steel sections of the Network.

Forecast capex costs relating to each of the above programs are provided in Table 8.9 below.

TABLE 8.9: OTHER DISTRIBUTION SYSTEM CAPEX FORECAST

$2014/15 million	2016/17	2017/18	2018/19	2019/20	2020/21	Total
HDPE Live Camera Inspection and Repairs (SA52)	2.3	2.3	2.3	2.3	2.3	**11.6**
Fire Safety Valves (SA31)	3.4	2.2	2.0	1.6	1.3	**10.5**
Replacement of Exposed PE Service Pipe (SA28)	1.4	1.4	1.4	1.4	1.4	**7.1**
Sleeved Railway Crossings (SA10)	0.4	0.4	0.4	0.4	0.4	**2.2**
Non Compliant Meter Installations (SA32)	0.3	0.3	0.3	0.3	0.3	**1.4**
Distribution Trunk Mains DCVG Survey and Dig-Ups (SA49)	0.4	0.2	0.2	0.2	0.2	**1.2**
Transmission Pipelines Dig-Up (SA36)	0.2	0.2	0.2	0.2	0.2	**1.0**
Insulation Flanges on Transmission Mains (SA37)	0.2	0.2	0.2	0.2	0.2	**0.8**
Corrosion Transmission Pipeline Mains M36 (SA53)	0.1	0.1	0.1	0.1	0.1	**0.7**
Installation of Corrosion Protection Units (SA06)	0.1	0.1	0.1	0.0	0.0	**0.4**
Total	**8.9**	**7.5**	**7.3**	**6.8**	**6.4**	**37.0**

Note: Totals may not add due to rounding.

8.5.6.4 Other Non-Distribution System Capex

This category covers miscellaneous capex that does not relate directly to the distribution system infrastructure. Full details relating to each of the projects listed are contained within the relevant Business Cases in Attachment 7.1. These projects include:

- *Plant and Equipment (Business Case SA30)* – this project relates to the continuation of routine expenditure to provide the appropriate tools, equipment and small capital items to install, repair and maintain the Network;

- *Fencing of Critical Infrastructure (Business Case SA69)* – this project involves improving the security of critical infrastructure sites within the Network; and

- *Gas Vents on HDPE Mains (Business Case SA56)* – this is the capex component of an opex project which relates to the installation of gas vents on HDPE mains in order to assist the detection of gas leaks.

Table 8.10 summarises the total costs of this category of capex.

TABLE 8.10: OTHER NON-DISTRIBUTION SYSTEM CAPEX FORECAST

$2014/15 million	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Plant and Equipment (SA30)	0.9	0.9	0.9	0.9	0.9	**4.4**
Fencing of Critical Infrastructure (SA69)	0.3	0.2	0.0	0.0	0.0	**0.4**
Gas Vents on HDPE Mains (SA56)	0.2	0.0	0.0	0.0	0.0	**0.2**
Total	**1.3**	**1.0**	**0.9**	**0.9**	**0.9**	**5.0**

Note: Totals may not add due to rounding.

8.6 Overheads

Overhead costs are applied to forecast capex in order to recover general business overheads that are not accounted for in the direct capex forecasts. These overhead costs generally 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 analysed actual overhead costs for the 2011/12, 2012/13 and 2013/14 regulatory years (i.e. the years where actual information is available for the current AA period) and has calculated the proportion of actual overhead costs incurred (see Table 8.11). The resultant average overhead rate is relatively consistent with the overhead rate of 10.7% approved by the AER for the current AA period.

TABLE 8.11: ACTUAL OVERHEADS AND CAPEX

$ million (nominal)	2011/12	2012/13	2013/14	Average
Actual Overheads	5.5	7.1	8.0	Not applicable
Actual Capex (excluding Overheads)	50.3	74.7	93.6	Not applicable
% Overheads to Capex	10.9%	9.6%	8.5%	9.6%

Note: Table 8.11 excludes the 2014/15 regulatory year because AGN does not currently have actual information for the whole year. The average is based on the latest actual information available to AGN.

AGN has applied the average overhead rate of 9.6% to the total forecast (direct) capex over the next AA period. The forecast overheads for the next AA period are shown in Table 8.12 below.

TABLE 8.12: OVERHEADS FORECAST

$2014/15 million	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Total	12.0	13.2	12.5	12.5	11.3	**61.5**

Note: Totals may not add due to rounding.

8.7 Escalators

Forecast capex has been split into three input cost categories: labour, construction labour and materials. The split between these input cost categories is based on an average of the historical breakdown of actual expenditure for each cost category for the 2011/12, 2012/13 and 2013/14 regulatory years (as per the discussion on overheads).

As noted in Chapter 7, AGN engaged BIS Shrapnel to develop forecasts of labour and construction labour cost escalation over the next AA period. Specifically, BIS Shrapnel has been engaged to forecast the rate of change in these input components above inflation, which is referred to as real cost escalation. Consistent with previous AER decisions, AGN has not applied real cost escalation to material costs. This section describes the labour cost escalators applied to forecast capex.

8.7.1 Labour

For the reasons explained in Chapter 7, AGN has applied an average of the BIS Shrapnel and Deloitte Access Economics (DAE) forecasts of real labour and construction labour price changes over the next AA period (see Section 7.10 of this AAI for a more detailed explanation on the approach used to calculate the real labour cost escalation rates). Table 8.13 sets out the resultant real labour and construction labour escalation rates.

TABLE 8.13: COST ESCALATION RATE FORECAST

	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Real Labour Cost Escalation Rate	0.45%	0.80%	0.91%	1.04%	1.19%	1.88%
Real Construction Labour Rate	0.14%	0.57%	1.00%	1.16%	1.39%	1.99%

Note: For the 2020/21 year AGN has applied BIS Shrapnel's forecast.

8.7.2 Total Escalators

Table 8.14 shows the combined impact of the forecast escalation rates on forecast capex over the next AA period.

TABLE 8.14: REAL COST ESCALATION FORECAST

$2014/15 million	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Total	0.7	1.8	2.9	4.2	5.6	**15.2**

Note: Totals may not add due to rounding.

8.8 Summary

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 MRP, which sets out the strategy for the replacement of ageing/deteriorating mains on the Network. Not surprisingly, the delivery of our MRP is one of the key issues of our AA Proposal, accounting for 60% of the total forecast capex. Other key drivers of our forecast capex include:

- *Growth capex* – which accounts for 16% of total capex and relates to connecting new consumers to the Network; and
- *IT* – which accounts for 10% of total forecast capex and relates to the continuation of the national program of work that was initiated in the current AA period.

AGN has provided the key asset management plans and Business Cases in support of the forecast capex. This provides the detailed information in relation to the capex forecasts outlined in this chapter, including a description, project justification and assessment against the relevant requirements of the NGR and the outcomes from our stakeholder engagement program. The resultant capex forecast is provided in Table 8.15 (excluding cost escalation and overheads) and Table 8.16 (including cost escalation and overheads). Table 8.17 details total forecast capex in nominal and in $2014/15 terms.

The capex forecast model, which shows the derivation of the capex forecasts, is provided as Attachment 8.8 to this AAI.

TABLE 8.15: BREAKDOWN OF CAPEX FORECAST (EXCLUDING COST ESCALATION AND OVERHEADS)

$2014/15 million	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Mains Replacement	75.2	74.1	73.6	75.8	71.3	**369.9**
Meter Replacement	4.2	4.0	3.7	2.9	2.3	**17.1**
Augmentation	1.6	8.8	4.3	2.3	0.8	**17.9**
Telemetry	0.3	0.2	0.2	0.2	0.1	**1.1**
Regulators	2.6	2.6	2.8	2.9	2.7	**13.6**
Information Technology	11.0	18.1	14.5	8.5	7.6	**59.7**
Growth Assets	18.8	18.8	19.4	24.9	19.2	**101.1**
Other Distribution System	8.9	7.5	7.3	6.8	6.5	**37.0**
Other Non-Distribution System	1.4	1.1	0.9	0.9	0.9	**5.0**
Total Capex	**124.0**	**135.2**	**126.7**	**125.2**	**111.4**	**622.5**

Note: Totals may not add due to rounding.

TABLE 8.16: BREAKDOWN OF CAPEX FORECAST (INCLUDING COST ESCALATION AND OVERHEADS)

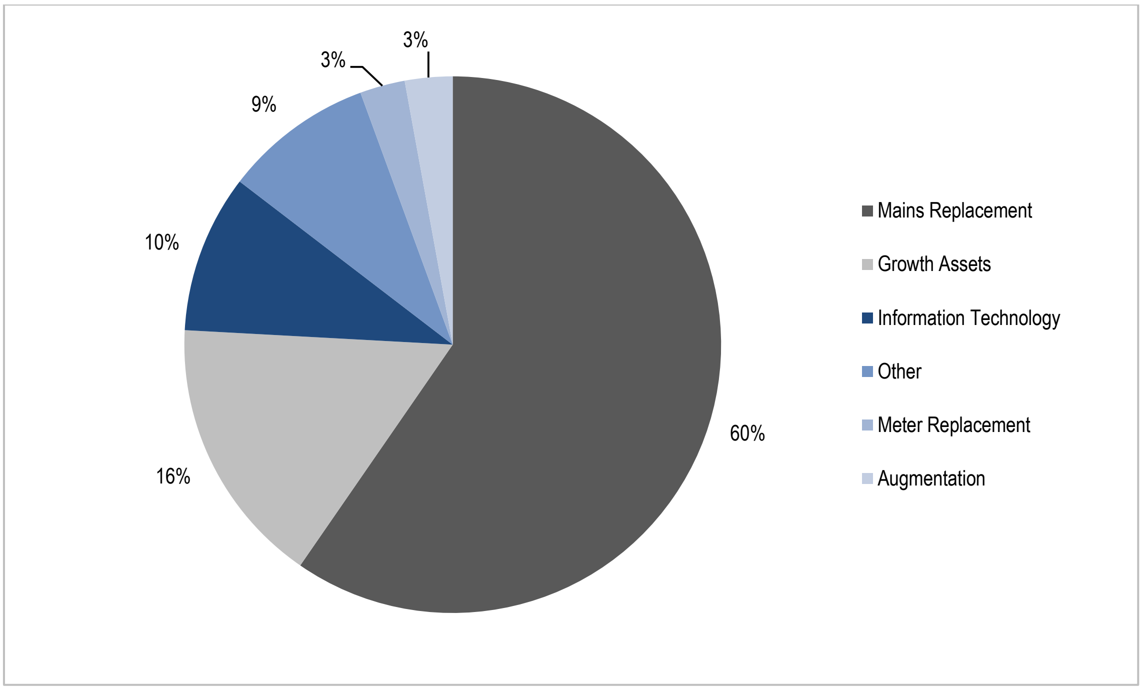
$2014/15 million	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Mains Replacement	83.0	82.4	82.7	86.2	82.4	**416.7**
Meter Replacement	4.6	4.4	4.1	3.3	2.6	**19.0**
Augmentation	1.8	9.8	4.9	2.7	1.0	**20.1**
Telemetry	0.3	0.3	0.2	0.2	0.2	**1.2**
Regulators	2.9	2.9	3.1	3.2	3.0	**15.1**
Information Technology	12.1	20.1	16.2	9.6	8.7	**66.7**
Growth Assets	20.7	20.9	21.7	28.2	22.1	**113.7**
Other Distribution System	9.8	8.3	8.1	7.6	7.3	**41.1**
Other Non-Distribution System	1.5	1.2	1.0	1.0	1.0	**5.5**
Total Capex	**136.7**	**150.3**	**142.0**	**141.9**	**128.2**	**699.1**

Note: Totals may not add due to rounding.

TABLE 8.17: CAPEX FORECAST INCLUDING COST ESCALATION AND OVERHEADS (REAL AND NOMINAL)

$ million	2016/17	2017/18	2018/19	2019/20	2020/21	Total
$2014/15	136.7	150.3	142.0	141.9	128.2	**699.1**
Nominal	142.1	160.0	155.0	158.7	146.9	**762.7**

FIGURE 8.3: FORECAST CAPITAL EXPENDITURE (INCLUDING COST ESCALATION AND OVERHEADS)



Note: Totals may not add due to rounding.

9 Regulatory Asset Base

Australian Gas Networks

Page intentionally left blank

9 Regulatory Asset Base

9.1 Introduction

This chapter explains how the value of the Regulatory Asset Base (RAB) has been adjusted for actual information over the current (2011/12 to 2015/16) Access Arrangement (AA) period. This chapter then adjusts the RAB for forecast information over the next (2016/17 to 2020/21) AA period.

9.2 Requirements of the National Gas Rules

Rule 77(2) of the National Gas Rules (NGR) provides that:

> *"If an access arrangement period follows immediately on the conclusion of a preceding access arrangement period, the opening capital base for the later access arrangement period is to be:*
>
> *(a) the opening capital base as at the commencement of the earlier access arrangement period adjusted for any difference between estimated and actual capital expenditure included in that opening capital base. This adjustment must also remove any benefit or penalty associated with any difference between the estimated and actual capital expenditure;*
>
> *plus:*
>
> *(b) conforming capital expenditure made, or to be made, during the earlier access arrangement period;*
>
> *plus:*
>
> *(c) any amounts to be added to the capital base under rule 82, 84 or 86;*
>
> *less:*
>
> *(d) depreciation over the earlier access arrangement period (to be calculated in accordance with any relevant provisions of the access arrangement governing the calculation of depreciation for the purpose of establishing the opening capital base); and*
>
> ***Note:***
>
> *See rule 90.*
>
> *(e) redundant assets identified during the course of the earlier access arrangement period; and*
>
> *(f) the value of pipeline assets disposed of during the earlier access arrangement period."*

Rules 82, 84 and 86 relate to capital contributions, speculative capital expenditure (capex) and the reuse of redundant assets respectively. Australian Gas Networks Limited (AGN) has not in the past, nor does it propose in the next AA period, to include any such amounts in the RAB. These parts of the NGRs have therefore not been considered further.

The requirements regarding conforming capex have been considered in Chapter 8 of this Access Arrangement Information (AAI).

Rule 90 states that in calculating depreciation for rolling forward the capital base from one access period to the next, any provisions governing the calculation of depreciation must resolve whether depreciation of the RAB is to be based on forecast or actual depreciation. The Australian Energy Regulator (AER) in its Final Decision for the current AA period determined that forecast depreciation is to be used in adjusting the RAB.

The requirements for establishing the projected (or forecast) RAB are set out in Rule 78 of the NGR. Rule 78 of the NGR states:

> *"The projected capital base for a particular period is:*
>
> *(a) the opening capital base;*
>
> *plus:*
>
> *(b) forecast conforming capital expenditure for the period;*
>
> *less:*
>
> *(c) forecast depreciation for the period; and*
>
> *(d) the forecast value of pipeline assets to be disposed of in the course of the period."*

Rule 89 of the NGR sets out the depreciation criteria. This Rule requires that:

> *"(1) The depreciation schedule should be designed:*
>
> *(a) so that reference tariffs will vary, over time, in a way that promotes efficient growth in the market for reference services; and*
>
> *(b) so that each asset or group of assets is depreciated over the economic life of that asset or group of assets; and*
>
> *(c) so as to allow, as far as reasonably practicable, for adjustment reflecting changes in the expected economic life of a particular asset, or a particular group of assets; and*
>
> *(d) so that (subject to the rules about capital redundancy), an asset is depreciated only once (ie that the amount by which the asset is depreciated over its economic life does not exceed the value of the asset at the time of its inclusion in the capital base (adjusted, if the accounting method approved by the AER permits, for inflation)); and*
>
> *(e) so as to allow for the service provider's reasonable needs for cash flow to meet financing, non-capital and other costs.*
>
> *(2) Compliance with subrule (1)(a) may involve deferral of a substantial proportion of the depreciation, particularly where:*
>
> *(a) the present market for pipeline services is relatively immature; and*
>
> *(b) the reference tariffs have been calculated on the assumption of significant market growth; and*
>
> *(c) the pipeline has been designed and constructed so as to accommodate future growth in demand.*
>
> *(3) The AER's discretion under this rule is limited.*
>
> ***Note:***
>
> *See rule 40(2)."*

Pursuant to Rule 40(2), the AER may not withhold its approval of an approach/forecast of depreciation if the AER is satisfied that the proposal complies with the applicable requirements and criteria set out in the NGL and NGR.

9.3 Regulatory Asset Base as at 1 July 2016

This section explains how AGN has adjusted the RAB over the current AA period to reflect actual information over that period.

9.3.1 Opening Regulatory Asset Base as at 1 July 2011

The opening RAB as at 1 July 2011 is $1,020 million ($ nominal), which has been derived:

- by taking from the AER Further Final Decision the opening capital base as at 1 July 2010 of $975 million ($ nominal), which reflects the latest actual information used by the model;[59]
- by adding the actual capex in 2010/11 of $41 million, adjusted as per the AER approach to rolling forward the RAB;
- by subtracting the forecast depreciation set by the AER of -$4 million (as per Rule 90, the AER decided that it would use forecast depreciation when adjusting the RAB for actual information over the current AA period);
- to result in a closing capital base as at 30 June 2011 of $1,020 million (in $ nominal).

The actual closing RAB of $1,020 million as at 30 June 2011 is slightly less than the forecast closing capital base of $1,024 million ($ nominal) set by the AER. This difference is largely explained by the difference between the forecast of net capex used for the current AA period for 2010/11 of $45 million (in $ nominal) and actual capex of $41 million.

9.3.2 Closing Regulatory Asset Base for the Current Access Arrangement Period

AGN has adjusted (or rolled forward) the RAB as at 1 July 2011 to derive a closing RAB as at 30 June 2016 (i.e. the end of the current AA period). AGN has adjusted the opening RAB by adding actual net capex less forecast depreciation plus inflation in each year of the current AA period. The inputs used by AGN to roll forward the RAB are described below.

9.3.2.1 Capital Expenditure

The conforming capex used to roll forward the RAB over the current AA period was determined by deducting capital contributions from gross capex (see Table 9.1). AGN considers that its actual capex in the current AA period is prudent, efficient and in accordance with good industry practice to achieve the lowest sustainable costs. As discussed in Chapter 8, AGN has strict governance and cost management protocols in place to ensure that actual capex is prudent and efficient. This includes:

- preparation of robust business plans and procedures governing asset management strategies and expenditure, particularly AGN's Asset Management Plan and all subordinate plans;
- application of rigorous analysis, including an assessment of various options, to ensure that the capex incurred by AGN provides the most prudent and cost effective long-term option for consumers;
- the significant experience and scale of our contractor, the APA Asset Management (APA), who's parent company (the APA Group) is the largest owner/operator of natural gas infrastructure in Australia;
- strict cost management protocols under the 2007 Operating and Management Agreement between AGN and the APA, including the processes around setting of annual budgets, the ongoing monitoring of actual performance against the budget and regular audits of incurred expenditure; and
- the existence of commercial and regulatory incentives to achieve lowest sustainable costs.

---

[59] AER 2011, "*Envestra Ltd: Access Arrangement Proposal for the SA gas network, 1 July 2011 – 30 June 2016*", Final Decision, June 2011, pg. 29.

TABLE 9.1: CONFORMING CAPEX FOR THE CURRENT AA PERIOD

$ million (nominal)	2011/12 actual	2012/13 actual	2013/14 actual	2014/15 forecast	2015/16 forecast
Gross Capex	55.8	81.5	98.4	104.6	128.5
Capital Contributions	0.3	1.6	0.6	0.9	0.2
Conforming Capex	55.5	79.9	97.8	103.7	128.3

Note: Totals may not add due to rounding.

9.3.2.2 Regulatory Depreciation over the Current Access Arrangement Period

AGN has used forecast depreciation to roll forward the RAB over the current AA period (see Table 9.2). This is consistent with the AER Final Decision, where the AER stated:

> *"…that forecast depreciation should be used to roll forward the capital base to 30 June 2016."*[60]

TABLE 9.2: REGULATORY DEPRECIATION FOR THE CURRENT AA PERIOD

$ million (nominal)	2011/12	2012/13	2013/14	2014/15	2015/16
Straight-line Depreciation	27.2	40.0	42.9	47.7	52.2
Less Inflation	33.4	17.7	28.8	36.3	17.8
Regulatory Depreciation	-6.1	22.2	14.1	11.4	34.4

9.3.2.3 Redundant Assets

Rule 85 of the NGR states that an AA may include a mechanism to ensure that assets that cease to contribute in any way to the delivery of pipeline services (redundant assets) are removed from the capital base. The AER in its Draft Decision for the current AA period stated that:

> *"… there is no evidence of any significant number or value of redundant assets in Envestra's [AGN's] network and the cost of identifying any that may exist is unlikely to be justified."*[61]

On this basis, and as set out in the following, the AER decided not to require any redundant assets to be removed from RAB in determining the opening RAB for the next AA period:

> *"The AER accepts that no adjustments for redundant assets are required to be made by Envestra [AGN] to its opening capital base."*[62]

This decision was maintained in the AER Final Decision. AGN notes that it has not in any event identified any redundant assets over the current AA period.

[60] AER 2011, "*Envestra Ltd: Access Arrangement Proposal for the SA gas network, 1 July 2011 – 30 June 2016*", Final Decision, June 2011, pg. 27.

[61] AER 2011, "*Envestra Ltd: Access Arrangement Proposal for the SA gas network, 1 July 2011 – 30 June 2016*", Draft Decision, February 2011, pg. 24.

[62] AER 2011, "*Envestra Ltd: Access Arrangement Proposal for the SA gas network, 1 July 2011 – 30 June 2016*", Draft Decision, February 2011, pg. 25.

9.3.2.4 Disposals

There have been no disposals of assets that are included in the RAB over the current AA period.

9.3.2.5 Inflation

AGN has applied inflation in a manner that is consistent with Section 4 of the South Australian AA Document, which requires use of the change in the March quarter Consumer Price Index (CPI) (All Groups Weighted Average for the Eight Capital Cities), as published by the Australian Bureau of Statistics. The actual inflation rate applied to the RAB is set out in Table 9.3.

TABLE 9.3: INFLATION ASSUMPTIONS

Change in the March Quarter CPI	
2011 Actual	3.26%
2012 Actual	1.63%
2013 Actual	2.50%
2014 Actual	2.93%
2015 Actual	1.33%

9.3.2.6 Financing Benefit

Rule 77(2)(a) of the NGR requires the opening RAB for the next AA period to be adjusted for any financing benefit or loss arising from the difference in forecast and actual capex in the final year of the previous AA period (i.e. 2010/11). As advised in Section 9.3.1 above, actual capex of $41 million was less than the forecast capex of $45 million. The $4 million difference in capex yielded a financing benefit to AGN of $3 million over the current AA period, which benefit has been deducted when setting the opening RAB for 1 July 2016.

9.3.2.7 Opening Asset Values as at 1 July 2016

Using the inputs outlined above, the RAB has been rolled forward over the current AA period. Table 9.4 shows that this results in an opening RAB as at 1 July 2016 (i.e. the start of the next AA period) of $1,429 million (in $ nominal).

TABLE 9.4: ROLL-FORWARD OF THE REGULATORY ASSET BASE 2011/12 TO 2015/16

$ million (nominal)	2011/12 actual	2012/13 actual	2013/14 actual	2014/15 forecast	2015/16 forecast
Opening Capital Base	1,019.9	1,084.6	1,145.9	1,234.4	1,332.2
Less Depreciation	27.2	40.0	42.9	47.7	52.2
Plus Conforming Capital Expenditure*	58.5	83.5	102.7	109.1	133.9
Plus Indexation	33.4	17.7	28.8	36.3	17.8
Less Funding Benefit	n/a	n/a	n/a	n/a	2.8
Closing Value	**1,084.6**	**1,145.9**	**1,234.4**	**1,332.2**	**1,428.8**

Note: The adjustment for the funding benefit accrued over the current AA period is made in the final year 2015/16.

Note: Totals may not add due to rounding.

** Conforming capex in Table 9.4 includes half a year of the weighted average cost of capital.*

9.4 Forecast Regulatory Asset Base

The forecast RAB for the next AA period has been determined by adjusting the closing value at 30 June 2016 (as set out in Table 9.4) for forecast capital expenditure, depreciation and inflation. Each of these matters is addressed in this section.

9.4.1 Capital Expenditure

The forecast capex for the next AA period is summarised in Table 9.5. The forecast capex has been allocated to the categories that are required to roll forward the RAB.[63] Capex is also expressed in end of year terms as required by the AER post-tax revenue model (and for this reason differs from that set out in Chapter 8).

TABLE 9.5: FORECAST CAPEX FOR THE NEXT AA PERIOD

$ million (nominal)	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Mains	94.6	105.2	103.0	113.7	103.3	**519.9**
Inlets	13.5	13.8	14.5	15.2	15.5	**72.5**
Meters	8.8	9.0	9.1	8.7	7.8	**43.5**
Telemetry	0.4	0.3	0.3	0.3	0.2	**1.4**
Information Technology Systems	12.8	21.9	18.1	11.0	10.2	**74.0**
Other Distribution System	13.5	12.2	12.5	12.4	12.0	**62.6**
Other	1.6	1.3	1.1	1.1	1.1	**6.2**
Equity Raising Costs	0.1	-	-	-	-	**0.1**
Total Capital Expenditure	**145.3**	**163.6**	**158.5**	**162.3**	**150.3**	**780.1**

Note: Totals may not add due to rounding.

9.4.2 Forecast Depreciation

The AER determines regulatory depreciation as straight-line depreciation less the inflation indexation that is applied to the RAB. This section discusses the determination of straight line depreciation and the proposed indexation adjustment to apply in determining regulatory depreciation for the next AA period.

9.4.2.1 Straight-line Depreciation

The straight-line approach to depreciation is the most common method used to depreciate the RAB. The straight line approach has the advantage of being easily understood, transparent and capable of being replicated on an ongoing basis. The straight line approach has been applied on the basis that the economic benefits from the assets that comprise the RAB will be realised equally over the useful/remaining life of those assets (i.e. the period where it is efficient to keep assets in service).

The assumption regarding the economic benefits of the RAB being realised equally over the life of an asset is no longer certain. As explained in Chapter 14, there has been an ongoing decline in the average usage of gas consumers and a slowing in connection rates. This reflects a range of factors, including warming weather trends, continuous improvements in energy efficiency (appliance efficiency and building thermal efficiency), customer appliance preferences (electric reverse-cycle air-conditioning instead of gas space heating) and the significant installation of solar equipment in recent years.

In addition to this, there are a range of other current and emerging pressures on the demand for natural gas over the next AA period, including:

---

63 AGN notes that there is an additional category called "Equity Raising Costs", which amount has been determined and treated in a manner that is consistent with that set out in the AER Post Tax Revenue Model Handbook – Amendment, December 2010, pg. 19-21.

- forecast (and substantial) increases in wholesale gas prices as a result of the commencement of the liquefied natural gas export industry in eastern Australia;
- further increases in renewable generation – a high penetration of 'green' electricity reduces the environmental driver for customers to adopt natural gas;
- emergence of new technologies – including continual technological improvements in distributed generation, battery storage and electric vehicles, which places further pressure on the willingness of consumers to choose to connect to natural gas (as they become more electricity focused);
- further increases in the penetration rates of reverse-cycle air-conditioners – which reduces the up-front cost of switching from gas to electricity; and
- a move to cost reflective electricity network prices – in areas with a peak summer load, such as South Australia, electricity tariffs would increase during peak times in summer and decrease in off-peak times in winter (i.e. during periods of peak (winter) gas demand).

The implication of the above factors is that the straight-line approach to depreciation may not be sustainable into the future. Depending on the impact of these factors, the ongoing (and likely higher rates of) decline in gas usage puts at risk the ability for AGN to efficiently recover the value of the RAB through the continual application of straight-line depreciation. This would be contrary to:

- Section 24(2) of the National Gas Law (NGL) – that service providers be provided with a reasonable opportunity to recover their efficient costs of supply; and
- Rule 89(1)(a) of the NGR – that depreciation be set in a way that promotes efficient growth in the (reference) services provided by the South Australian gas distribution network (the Network).

With regard to the latter, the NGR requires that the profile of depreciation be set, to the extent possible, to reflect the utilisation of assets. This means that more depreciation is recovered when network usage (or utilisation) is high relative to periods where network usage is low. The impact being that there is a strong argument to increase the depreciation on the RAB now in light of the known/expected ongoing decline in usage of the Network.

This matter was considered by the Office of the Regulator General (ORG) in Victoria (now the Essential Services Commission of Victoria). The ORG suggested that the depreciation method should be continually reviewed as more information becomes available and that the depreciation method should be conservative. Specifically, the ORG stated:

> *"The potential complexity of determining economic depreciation, combined with the likely imprecision, suggest that a relatively simple method for calculating regulatory depreciation would be appropriate. However, as information on the factors that influence economic depreciation will be revealed over time, there should also be a preparedness to review the method at future price reviews. In addition, this level of uncertainty, coupled with the advantages of reducing the level of risk faced by the distribution licensees, suggests that the method should err on the side of exceeding, rather than lagging, expected economic depreciation."*[64]

While concerned over the ability to recover efficient costs, AGN is proposing to continue to apply the straight-line depreciation method over the next AA period. AGN reiterates that this approach has considerable risk, particularly regarding the ability for AGN to recover the value of the RAB in an environment of declining network usage. For this reason, AGN notes that continuing to apply straight-line depreciation may not be consistent with the above NGL and NGR requirements relating to depreciation.

[64] ORG 1999, "*Consultation Paper no.4 2001 Electricity Distribution Price Review, Cost of Capital Financing*", May 1999, pg.15.

AGN is proposing to apply the same standard useful life assumptions as those approved by the AER to apply over the current AA period. AGN has also used the same approach to determining the remaining life of the RAB at the start of the next AA period, as required by the AER post-tax revenue model (PTRM).[65] The standard useful life and remaining life assumptions to apply over the next AA period are set out in Table 9.6.

TABLE 9.6: SUMMARY OF LIVES USED TO CALCULATE DEPRECIATION

Asset Category	Standard Useful Life (years)	Remaining Life
Mains	60.0	49.1
Inlets	60.0	51.1
Meters	15.0	7.4
Telemetry	20.0	12.7
Information Technology Systems	5.0	3.7
Other Distribution Equipment	40.0	23.7
Other	10.0	7.2

Based on the above, the forecast straight-line depreciation over the next AA period is set out in Table 9.7.

TABLE 9.7: STRAIGHT-LINE DEPRECIATION FOR THE NEXT AA PERIOD

$ million (nominal)	2016/17	2017/18	2018/19	2019/20	2020/21
Straight-line Depreciation	47.1	53.9	62.9	69.7	72.9

9.4.2.2 Indexation

The AER reduces the amount of straight-line depreciation by the amount of inflation (or indexation) that is applied to the RAB. That is, compensation for changes in inflation are capitalised into the RAB by decreasing the amount of depreciation provided to the business. This approach provides only the real element of the return in cash, and as such, has the impact of slowing the rate of return of capital to the business. This reduces cash flows in the short term relative to an approach where this indexation adjustment was not made.

As noted in Section 9.2, Rule 89(1)(e) of the NGR requires that the depreciation schedule should be designed:

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

The AER, in setting the rate of return, assumes that the benchmark efficient business has a 'BBB+' credit rating from Standard & Poor's (S&P) and a 'Baa1' credit rating from Moody's. S&P consider both the business risk profile and the financial risk profile when setting the credit rating of a business. In terms of the latter, S&P consider the following two key financial ratios:

- *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 principal); 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).

[65] The PTRM requires that the remaining life of assets in service at the start of the regulatory period be determined. This is to determine the extent of depreciation, on average, that is required to be applied to the opening capital base over the current AA period. AGN has applied an approach to determining remaining asset lives that is consistent with that used by the AER.

FFO is calculated as total revenue less interest, operating expenditure (opex) and tax. Assuming the highest business risk profile of ‘excellent’, S&P require a sustained FFO-to-debt ratio of at least 9% and a FFO to interest ratio above 2.5. The key focus of the credit rating agencies is most likely to be on the FFO to debt ratio given the prevailing very low interest rate environment.

AGN has considered whether the required credit metrics are maintained under the following two scenarios, which each assume a capital structure in line with the AER’s target 60% debt-to-RAB ratio:

- *Scenario 1:* the cash flow derived from our AA proposal; and
- *Scenario 2:* the cash flow derived from our AA proposal adjusted for the most recent AER decision on the regulatory rate of return of 5.45% set out in its Preliminary Decision for SA Power Networks (SAPN).

The two scenarios are set out in Table 9.8. This shows that the required credit metrics for a BBB+ rated business are (just) met for our revised AA proposal. The required BBB+ credit metrics are, however, not met if the AER were to substitute a lower rate of return such as that used most recently for SAPN. AGN engaged Mr. Jeff Balchin of Incenta Economic Consulting to undertake an independent review of the above two scenarios (see Attachment 5.1). Incenta reached the same conclusion as AGN, stating that:

> *“The clear conclusion from my assessment of AGN’s credit metrics if a WACC [Weighted Average Cost of Capital] consistent with what was applied to SA Power Networks is applied and no other changes are made to improve financeability is that:*
>
> - *A stand-alone entity in AGN’s positon would have credit metrics that are below what is required to attract and maintain a BBB+/Baa1 credit rating, and*
> - *Indeed the metrics are sufficiently poor that there is a material risk as to whether a BBB credit rating could be maintained.*
>
> *Accordingly, applying such a WACC without also applying measures to improve financeability would be inconsistent with the NGL and NGR, and most notably:*
>
> - *Inefficiently raise the cost of finance, which is likely to be detrimental to the interests of users over the long term,*
> - *Create a situation where a benchmark regulated business would not be able to earn a commercial return and recover at least its efficient cost because it would not be in a position to achieve the credit rating the AER has assumed, and*
> - *Would not result in the service provider’s legitimate needs for cash flow being met, and so is not consistent with rule 89(1)(c) of the NGR.*
>
> *My analysis suggests that if the provider is compensated fully for inflation in a cash sense, then this would be sufficient to generate credit metrics that are consistent with a BBB+/Baa1 rating, and which would endure over the 40 year forecast period that was analysed.”*[66]

[66] Incenta Economic Consulting 2015, “*Using the Profile of Prices During an Access Arrangement Period and Return of Capital to Improve Financial Metrics*”, June 2015, pg. 4-5. Provided as Attachment 5.1 to this AAI.

TABLE 9.8: CREDIT METRICS INDEXATION FOR THE NEXT AA PERIOD

		2016/17	2017/18	2018/19	2019/20	2020/21	S&P BBB+	Moody's Baa1
Proposal Case (rate of return of 7.3%)	FFO/debt	8.5%	8.5%	8.0%	8.0%	8.4%	≥9.0%	≥9.0%
	FFO Interest Cover	2.6	2.6	2.5	2.5	2.5	Not applicable	>2.5x
Proposal Case (rate of return of 5.45%)	FFO/debt	6.6%	6.7%	6.4%	6.4%	6.8%	≥9.0%	≥9.0%
	FFO Interest Cover	2.5	2.5	2.5	2.5	2.6	Not applicable	>2.5x

There are several ways that the AER could increase the cash flow to the business without altering the levels of compensation provided, including:

- to vary the level of indexation that is applied to the RAB, which would have the effect of changing the depreciation profile (and hence cash flow) to the business; or
- to shift the classification of capex to opex, which again increases the cash flow available to the business.

The requirements of Rule 89(1)(e) of the NGR facilitate the option of varying the level of indexation that is applied to the RAB. AGN believes that the indexation only needs to be varied to the extent required to provide sufficient cash flow to maintain the benchmark BBB+ credit rating that is assumed by the AER in setting the regulatory rate of return.[67] AGN considers that the AER is required to undertake this financeability test in order to determine the appropriate level of indexation to provide to the business.

AGN notes that a number of regulators in Australia and overseas apply financeability tests to ensure that their decisions provide sufficient revenues/cash flows to maintain a pre-determined credit rating. For example, the Office of Gas and Electricity Markets (Ofgem) in the United Kingdom considers a number of credit metrics to ensure its decisions are consistent with a BBB-to-A credit rating. This has led Ofgem to accelerate depreciation in a number of its decisions. This was noted by Incenta, who stated:

> *"The other reasonably straightforward mechanism for adjusting the rate of depreciation to improve financeability is to alter the lives of assets. It is notable that in the United Kingdom adjustments have been made to the asset lives, in addition to adjustments to the profile of depreciation, for the same purpose. In one case Ofgem sought to shorten the average asset age so that capital is returned sooner to investors and, as such, minimising the potential for cash flow and financeability issues. Further, it accelerated the depreciation associated with expenditure already incurred."*[68]

Ofgem also consider financeability in deciding on the split between opex (which Ofgem refer to as 'fast' money) and capex (which Ofgem refer to as 'slow' money). For example, Incenta notes that:

> *"Financeablity is also an important consideration for Ofgem in deciding on its allocation between its 'fast pot' (i.e. recovery in the year, akin to operating expenditure) and its 'slow*

---

67 Importantly, varying the levels of indexation will not provide a windfall gain to AGN. Rather, it will merely alter the timing at which the capital costs are returned to the business. That is, the Net Present Value of the two different cash flows from increasing indexation and not increasing indexation is identical, and in fact in undiscounted terms total revenues are lower with an indexation adjustment.

68 Incenta Economic Consulting 2015, "*Using the Profile of Prices During an Access Arrangement Period and Return of Capital to Improve Financial Metrics*", June 2015, pg. 10. Provided as Attachment 5.1 to this AAI.

> *pot' (i.e. the spread over an extended period, akin to capital expenditure) under its TOTEX [Total Expenditure] approach. In this case, the businesses are able to propose the ratio between the 'fast pot' and the 'slow pot' having regard to the impact this has for financeability. For instance, in its recent decisions on electricity distribution businesses Ofgem allowed a distributor to reduce its capitalisation rate (i.e. slow pot money) from 72 per cent to 68 per cent, thereby increasing is proportion of 'fast pot' money. Ofgem justified this approach on the basis of improved financeability…"*[69]

AGN has not, however, varied the level of the indexation adjustment to depreciation on the basis that this AA proposal allows the business to maintain a BBB+ credit rating over the next AA period (as per Table 9.9). The level of indexation to apply over the next AA period is shown in Table 9.9.

TABLE 9.9: INDEXATION FOR THE NEXT AA PERIOD

$ million (nominal)	2016/17	2017/18	2018/19	2019/20	2020/21
Indexation	35.7	39.1	42.8	46.2	49.7

9.4.2.3 Regulatory Depreciation

The straight-line depreciation, indexation adjustment and resultant regulatory depreciation for the next AA period is set out in Table 9.10 AGN again notes that the AER will need to consider the amount of indexation to apply to the RAB should it materially alter this revised AA proposal.

TABLE 9.10: REGULATORY DEPRECIATION FOR THE NEXT AA PERIOD

$ million (nominal)	2016/17	2017/18	2018/19	2019/20	2020/21
Straight-line Depreciation	47.1	53.9	62.9	69.7	72.9
Less Indexation	35.7	39.1	42.8	46.2	49.7
Regulatory Depreciation	11.4	14.9	20.1	23.4	23.2

9.4.3 Capital Redundancy Policy

As noted earlier, the AER did not require AGN to identify and remove any redundant assets from the RAB over the current AA period. The AER's decision was made on the basis that:

- there was not any evidence of any significant number or value of redundant assets in AGN's network; and
- the cost of identifying any redundant assets that may exist is unlikely to be justified.

AGN is not aware of any assets that will be made redundant over the next AA period. Given this, AGN is proposing to maintain the policy that no redundant assets be removed from the RAB over the next AA period.

9.4.4 Disposals

AGN is not aware of any assets that will be disposed of over the next AA period.

---

69 Incenta Economic Consulting 2015, "*Using the Profile of Prices During an Access Arrangement Period and Return of Capital to Improve Financial Metrics*", June 2015, pg. 11. Provided as Attachment 5.1 to this AAI.

9.4.5 Inflation

AGN has applied a forecast inflation rate of 2.5% to the RAB over the next AA period. This assumption reflects the mid-point of the inflation target set by the Reserve Bank of Australia (RBA). AGN is however concerned that this forecast will overstate inflation over the next AA period, particularly given the most recent actual inflation rate of 1.33% (see Table 9.3). This point was made by Dr Tom Hird of CEG, who noted that:

> *"The AER's inflation estimation methodology assumes that expected inflation is equal to:*
>
> - *the RBA's most recent forecast of short term inflation published in the quarterly Statement of Monetary Policy. This provides a forecast of up to two years inflation; plus*
> - *an assumption that investors expect inflation to be 2.5% in every year thereafter, which corresponds to the mid-point of the RBA's inflation target band.*
>
> *I consider this approach to be broadly reasonable in most market circumstances where investors expect that monetary policy can be relied on to return inflation to, and maintain inflation at, the midpoint of the RBA's target range.*
>
> *However, I do not consider this to be reflective of the current market circumstances, considering the fact that:*
>
> - *global inflation rates have been persistently below target, with instances of deflation in the US, Japan, the UK and the Eurozone;*
> - *the ability of monetary policy to provide economic stimulus is limited, given the proximity of official interest rates to the 'zero lower bound', coupled with the fact that, at current low interest rates, further rate reductions are of uncertain value in terms of providing economic stimulus; and*
> - *the IMF's April 2015 World Economic Outlook publication specifically mentions Australia as being at risk of falling into a low inflation trap."*[70]

Dr Hird develops a specific inflation forecast for use in the AER PTRM based on the difference in yields on nominal and inflation indexed Commonwealth Government Securities. This results in a forecast of inflation of 2.06% over the South Australian Power Networks' (SAPN) averaging period of 9 February to 6 March 2015, which is far closer to actual inflation in the past year (the SAPN averaging period is largely consistent with that used by AGN in this AA Proposal).

AGN intends to adopt a market based estimate by applying the same methodology used by Dr Hird (and explained in Attachment 9.1) if the June 2015 quarter inflation outcome does not materially increase from the March 2015 quarter inflation outcome. AGN considers this approach has the benefit of being based on actual market information rather than broad market expectations, and as such, is more consistent with the type of information relied upon by the AER and AGN to estimate the rate of return (see Chapter 10).

9.4.6 Forecast Regulatory Asset Base Roll Forward

The forecast RAB over the next AA period, taking into account forecast regulatory depreciation, capex and inflation, is set out in Table 9.11. This shows a closing RAB of $2,116.0 million as at 30 June 2021 in nominal dollar terms.

[70] CEG 2015, *"Measuring Expected Inflation for the PTRM",* June 2015, pg. 3. Provided as Attachment 9.1 to this AAI.

TABLE 9.11: ROLL-FORWARD OF THE REGULATORY ASSET BASE IN THE NEXT AA PERIOD

$ million nominal	2016/17	2017/18	2018/19	2019/20	2020/21
Opening Capital Base	1,428.8	1,562.7	1,711.5	1,849.9	1,988.8
Plus Conforming Capital Expenditure	145.3	163.6	158.5	162.3	150.3
Less Straight-line Depreciation	-47.1	-53.9	-62.9	-69.7	-72.9
Indexation Adjustment	35.7	39.1	42.8	46.2	49.7
Closing Value	**1,562.7**	**1,711.5**	**1,849.9**	**1,988.8**	**2,116.0**

Note: Totals may not add due to rounding.

9.4.7 Opening Regulatory Asset Base as at 1 July 2021

Pursuant to Rule 90(2) of the NGR, AGN proposed that actual depreciation be used for the current AA period. The AER, however, did not accept this proposal, instead favouring the use of forecast depreciation to establish the opening RAB as at 1 July 2016. The AER stated in its Final Decision that it:

> *"…considers that a forecast depreciation approach should be used to establish Envestra's [AGN's] opening capital base for the access arrangement period commencing 1 July 2016. While a forecast depreciation approach may not create as great an efficiency incentive as an actual depreciation approach, the AER considers this appropriate given the nature of the gas distribution industry. A forecast depreciation approach is neutral in terms of its impact on a business's spending on capex. It does not encourage deferral of spending nor discourage the maintenance of service quality. If capex forecasts prove to be well off target, above or below, it reduces the risk to the service provider and customers by removing from the capital base only the depreciation that had actually been allowed for by the regulator.*
>
> *…With regard to Envestra's argument for consistency between incentives for opex and capex efficiency, the AER considers that an actual depreciation approach is not an efficiency incentive mechanism. Even if it has incentive properties – to reduce expenditure – it does not have the mechanics of other incentive mechanisms such as the EBSS [Efficiency Benefit Sharing Scheme]. There are also broader concerns (including the issue of Envestra's ability to deliver its projected mains replacement program at the rate it proposes) that must be weighed up by the AER in making its decision."*[71]

AGN noted that, as explained in Chapters 2 and 8, AGN delivered the full mains replacement program approved by the AER over the current AA period. AGN also notes that it has proposed a more formal capital incentive scheme apply to the business over the next AA period (see Chapter 12). On this basis, AGN accepts the preference of the AER to use forecast depreciation to determine the opening RAB as at 1 July 2021.

AGN will, however, reconsider this position in the event that the AER does not accept our proposed capital incentive scheme to apply over the next AA period.

9.5 Summary

AGN has determined an opening RAB as at 1 July 2016 of $1,428.8 million ($ nominal) and a forecast closing RAB as at 30 June 2021 of $2,116.0 million ($ nominal).

---

[71] AER 2011, "*Envestra Ltd: Access Arrangement Proposal for the SA gas network, 1 July 2011 – 30 June 2016*", Draft Decision, February 2011, pg. 48.

TABLE 9.12: CLOSING VALUE OF REGULATORY ASSET BASE AS AT 30 JUNE 2021

Closing Value of Capital Base	$ million
Nominal	2,116.0
Real ($2015/16)	1,870.2

10 Rate of Return

Page intentionally left blank

10 Rate of Return

10.1 Introduction

The single largest cost faced by Australian Gas Networks Limited (AGN) relates to financing the $1.5 billion investment already made in the South Australian natural gas distribution network (the Network). The rate of return on our investment accounts for around half of the total revenue recovered by AGN over the next (2016/17 to 2020/21) Access Arrangement (AA) period (see Chapter 13).

Achieving a fair and reasonable rate of return is therefore a key factor in promoting the long-term interests of consumers. For example, achieving a reasonable rate of return is essential in order for AGN to attract the funding from shareholders (through equity) and debt providers to continue to undertake the necessary investment in the Network over the next AA period.

AGN is proposing a significant reduction in the rate of return, from 10.28% (nominal, post-tax) applying in the current (2011/12 to 2015/16) AA period to 7.23% proposed for the next AA period. This reduction reflects the fall in interest rates that has occurred following the passing of the global financial crisis. The benefit of these lower interest rates will be passed through to consumers through relatively lower prices over the next AA period.

The proposed rate of return reflects all available and relevant data, estimation methods, financial models and evidence. AGN has also relied upon the advice of independent experts. AGN has carefully considered previous decisions made by the Australian Energy Regulator (AER), including that set out in its Rate of Return Guideline and in recent regulatory decisions (referred to as the AER 2015 decisions).[72]

This chapter explains the reasons for our proposed 7.23% rate of return. This includes a discussion of the relevant requirements of the National Gas Law (NGL) and National Gas Rule (NGR), recent changes to the NGR made in 2012 as they relate to the rate of return and the derivation of the cost of equity and cost of debt (which are combined to determine the overall rate of return).

More detailed reasoning on our approach to estimating the rate of return is provided in Attachment 10.1 and related attachments to this Access Arrangement Information (AAI).

10.2 Requirements of the National Gas Rules

Rules 87(1) to 87(12) of the NGR establish the framework for estimating the rate of return. Rule 87(2) requires the rate of return to be determined such that it achieves the allowed rate of return objective (ARORO), which is set out in Rule 87(3) and states:

> *"…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..."*

Other relevant parts of the NGR regarding the rate of return include:

- Rule 87(4) – which provides that the rate of return is to be a weighted average of the return on equity and return on debt that is determined on a nominal vanilla basis and is consistent with the estimate of the value of imputation credits (see Chapter 11);
- Rule 87(5) – which states that regard must be had to relevant estimation methods, financial models, market data and other evidence;

72 The AER has recently published Final Decisions in respect of TransGrid, Ausgrid, Endeavour Energy and Essential Energy, ActewAGL, TasNetworks, Directlink and Jemena Gas Networks (JGN) and Preliminary decisions for Energex, Ergon Energy and SA Power Networks.

- Rules 87(6) and 87(7) – that the return on equity is to be estimated such that it contributes to the achievement of the ARORO and has regard to prevailing conditions in the market for equity funds;
- Rules 87(8) to 87(12) – which includes that the return on debt is to be estimated to contribute to the achievement of the ARORO, may be estimated based on a methodology that results in the return on debt being the same or different for each year of an AA period, may reflect either prevailing or historical returns required by debt investors (or some combination of both) considers the interrelationship with the return on equity, has regard to the incentives on capital expenditure and considers any impacts in changing the methodology to estimate the return on debt from one AA period to the next.

As noted in Chapter 1, the rate of return is required to be estimated such that it best achieves the National Gas Objective (NGO). The NGO requires the rate of return to promote efficient investment in natural gas services for the long-term interests of consumers of natural gas. The rate of return must also take into account the Revenue and Pricing Principles (RPP), which include providing a reasonable opportunity to recover efficient costs, promote economic efficiency and to have regard to the potential for under or over investment.

10.3 Changes to the National Gas Rules in 2012

In 2012 the Australian Energy Market Commission (AEMC) made changes to the rate of return framework set out in Rule 87 of the NGR. The key focus of the change was to put a greater emphasis on achieving an overall rate of return objective (being the ARORO outlined in Section 10.2) and to explicitly allow for the consideration of more information to inform the rate-of-return estimate.

The AEMC formed the view that the flexibility to consider a broad set of information under the previous Rule 87 had not been taken advantage of in practice. The AEMC was particularly concerned about the formulaic approach to rate of return estimates that had developed in regulatory practice. The AEMC noted:

> *"Moreover, recent decisions of the [Australian Competition] Tribunal have interpreted the NGR rate of return framework to apply in such a way as to reduce the range of information that can be used in estimating the rate of return. Such application could lead to the adoption of relatively formulaic approaches to determining the rate of return rather than focusing on the overall estimate."*[73]

Likewise, the AEMC noted the application and interpretation of the previous Rule 87, including the use of the Sharpe-Lintner (SL) Capital Asset Pricing Model (CAPM) alone to determine the cost of equity:

> *"…presupposes the ability of a single model, by itself, to achieve all that is required by the objective. The Commission is of the view that any relevant evidence on estimation methods, including that from a range of financial models, should be considered to determine whether the overall rate of return objective is satisfied."*[74]

The AEMC considered that "*no one method can be relied upon in isolation to estimate an allowed return on capital that best reflects benchmark efficient financing costs*".[75] The AEMC formed the view that, without amendment, the rate of return rules would not likely deliver outcomes that best meet the NGO and the RPP, and as such, that a new rate of return framework was needed. Accordingly, the amended Rule 87 reflects a significant shift in the approach to setting the required rate of return.

---

73 AEMC 2012, "*AEMC Rule Determination, National Gas Amendment (Price and Revenue Regulation of Gas Services)*", Rule 2012, November 2012, pg. 41.

74 AEMC 2012, "*AEMC Rule Determination, National Gas Amendment (Price and Revenue Regulation of Gas Services)*", Rule 2012, November 2012, pg. 48.

75 AEMC 2012, "*AEMC Rule Determination, National Gas Amendment (Price and Revenue Regulation of Gas Services)*", Rule 2012, November 2012, pg. 49.

AGN considers that the changes to the NGR are a substantial improvement to the framework for estimating rate of return.

10.4 AER Rate-of-Return Guideline

Rule 87(13) requires the AER to publish, every three years, a non-binding rate-of-return guideline setting out its intended approach to estimating the rate of return. The AER published the first guideline on 17 December 2013 (referred to as the Guideline). While it is not mandatory to follow the Guideline, the AER must state its reasons for making a decision that is not in accordance with the Guideline (Rule 87(18)).

AGN agrees with many key factors for estimating the rate of return set out in the Guideline and applied in the AER 2015 decisions. This includes the use of a 10-year trailing average for estimating the return on debt (although there are differing views on the method of transition to this approach) and the relevant financial models for estimating the return on equity (although there are differing views on how these models should be used). AGN also agrees with the 60% gearing assumption used to determine the rate of return.

The remainder of this chapter explains AGN's proposed approach to determine the return on equity and the return on debt and identifies where this approach departs from the AER Guideline.

10.5 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. This means that AGN must use financial models and other market evidence to inform the estimate of the return on equity.

There is no one universally accepted model that is (or should be) used to estimate the return on equity. AGN therefore relies on four relevant and well accepted financial models, giving each model a weighting to arrive at a single return on equity of 9.91% (see Table 10.1).[76] This is commonly referred to as the 'multi-model' approach to setting the return on equity, and is based on substantial expert advice (see Attachment 10.1)

TABLE 10.1: ESTIMATES OF THE REQUIRED RETURN ON EQUITY FOR A BENCHMARK EFFICIENT ENTITY

Method	Required Return on Equity	Weighting
Sharpe-Lintner Capital Asset Pricing Model	9.28%	12.50%
Black Capital Asset Pricing Model	9.89%	25.00%
Fama-French Model	9.88%	37.50%
Dividend Discount Model	10.29%	25.00%
Weighted Average	**9.91%**	**100.00%**

The use of the multi-model approach represents a departure from the AER Guideline and AER 2015 decisions. The AER instead places sole reliance on the SL CAPM, with certain other financial models and information used to inform the parameters required by this model. These parameters are also required to implement the multi-model approach. AGN has departed from the AER Guideline in respect of the following parameters:

- *Equity beta estimate* – AGN considers both domestic and foreign data to produce a reliable and best estimate of the equity beta of 0.82 (the AER relies primarily on domestic data to arrive at its estimate of 0.70); and

[76] Frontier Economics 2015, "*An Updated Estimate of the Required Return on Equity, A report for Australian Gas Networks*", June 2015.

- *Market risk premium* – AGN considers the best estimate is 8.23%, taking into account all relevant evidence on the market risk premium and applying a weighting based on the strengths and weaknesses of this evidence (the AER relies primarily on historical excess returns to arrive at its estimate of 6.5%).

Table 10.2 sets out the parameters used by AGN in its multi-model approach, which parameters have been informed by the independent expert advice detailed in Attachment 10.1.

TABLE 10.2: PARAMETERS USED BY AGN IN ITS MULTI-MODEL APPROACH

Parameters	AGN Proposal
Risk Free Rate (Average of 10-year Commonwealth Government Securities yields over agreed averaging period)	2.55% (Using a place-marker 20 day averaging period ending on 6 March 2015)
Equity Beta	0.82
Market Risk Premium	8.23%

The multi-model approach has regard to all relevant financial models for the purposes of estimating the return on equity. The weightings applied to each model are based on the relative strengths and weaknesses of each model. The multi-model approach gives rise to stable returns over time that better reflect prevailing market conditions for equity funds when compared to a return on equity estimated solely on the basis of the SL CAPM.

AGN considers that the multi-model approach best achieves the ARORO, the NGO and the RPP.

10.6 Return on Debt

The return on debt reflects the return required by debt holders on issued debt. The return on debt can be observed by reference to the price and promised payments on traded bonds for firms with a similar degree of risk as the benchmark efficient entity.

AGN agrees with the AER that the return on debt should be estimated based on a 10-year trailing average of the cost of debt incurred by a benchmark efficient business. The key area of difference is how to transition to this new approach from the previous 'on-the-day' approach, which estimated the cost of debt based on a short-term averaging period just prior to the start of an AA period. While there are a number of options, the most common are:

- *the AER transition approach* – which implements a 10-year transition to implementing the 10-year trailing average approach;
- *no transition approach* – which implements the 10-year trailing average approach at the start of the regulatory period; and
- *a hybrid transition approach* – which implements a 10-year transition to the base rate component but not to the debt risk premium (DRP) component of the cost of debt.

AGN is proposing the hybrid transition approach on the basis that this is most consistent with the debt financing practices of a benchmark efficient business, facing the risks of AGN in providing the Reference Services, in moving to a trailing average approach.[77] Indeed, better replicating the financing practices of a benchmark efficient business was the key driver in moving to a 10-year trailing average cost of debt.

[77] AGN accepts that a hedging strategy may not have been efficient for every business and that an alternative financing strategy may have been to simply issue fixed rate debt on a staggered basis. AGN believes that there is likely to have been multiple benchmark efficient approaches under the 'on the day approach' and the AEMC recognised there could be more than one efficient benchmark. If there is only one single benchmark efficient debt management strategy, then the correct single benchmark would reflect a trailing average approach without transition, being the efficient approach that is in fact replicable by all firms, rather than the hybrid methodology replicable by only some firms. This is addressed in Attachment 10.1.

Consistent with the hybrid approach (which the AER accepts was an efficient approach under the 'on the day' methodology), no transition is required for the debt risk premium component of the cost of debt given businesses such as AGN already have a trailing average DRP (reflecting that it is not possible to 'hedge' the DRP).

The hybrid transition approach is consistent with the actual transactions that a benchmark efficient entity facing the risks of AGN would need to enter into to transition to the 10-year trailing average approach.[78] This approach therefore best reflects the efficient financing costs of the benchmark efficient entity as required by the ARORO. A detailed explanation of the mechanics of the hybrid transition method is set out in Attachment 10.22.

The hybrid transition approach gives rise to a cost of debt of 5.44% (annualised) over the placeholder averaging period, which is comprised of:

- *base interest rate of 2.52%* – measured as the average of one-to-10-year swap rates over the AGN placeholder period of 9 February 2015 to 6 March 2015; plus
- *debt risk premium of 2.35%* – measured as the 10-year trailing average spread to the 10-year swap rate measured over the period 1 July 2005 to 30 June 2014 plus the placeholder period of 9 February 2015 to 6 March 2015; plus
- *swap transaction costs of 23 basis points* – which reflect the transaction costs of implementing a swap portfolio; plus
- *new issue premium of 27 basis points* – which reflects the difference between the cost of debt faced by an issuer in the primary market (where service providers issue debt) and the estimate of yields or bonds observed in the secondary market (where the AER's cost of debt estimates are observed).

Our approach to setting the cost of debt and for updating the cost of debt for each regulatory year of the next AA period is set out in Attachment 10.1.

10.7 Key Departures from the Rate of Return Guidelines

AGN has proposed to depart from the AER Rate of Return Guideline and 2015 decisions to estimate the cost of equity and the cost of debt in the following ways:

- AGN has adopted the multi model-approach to estimating the return on equity instead of placing sole reliance on the SL CAPM (the SL CAPM is referred to by the AER as its 'foundation model');
- AGN has adopted an equity beta of 0.82 and a market risk premium of 8.23%, which differs from the parameter estimates used by the AER of 0.70 and 6.5% respectively; and
- AGN has adopted the hybrid transition approach to the 10-year trailing average cost of debt rather than the AER transition.

10.8 Summary

AGN has accepted many elements of the AER Guideline and 2015 decisions in estimating the rate of return. Our proposal departs from the AER where necessary in order to ensure that the allowed rate of return meets the requirements of the ARORO, the RPP and contributes to the NGO to the greatest extent. Setting a rate of return as proposed by AGN is essential to ensure that AGN continues to attract the necessary equity and debt funding required to invest in the Network.

---

[78] However, for the reasons set out in the CEG report *Efficient use of interest rate swaps to manage interest rate* risk, June 2015 and Attachment 10.1, hedging 100% of the base rate of interest was not necessarily the best way to minimise interest rate risk under the 'on the day approach'.

AGN has sought the opinion of Dr Greg Houston of HoustonKemp Economists on whether our approach to estimating the rate of return is materially preferable in making a contribution to the NGO relative to the AER Guideline and 2015 decisions (see Attachment 1.6). Dr Houston has considered the various expert reports on which AGN relies in respect of its rate of return proposal. The key conclusion of Dr Houston is as follows:

> *"In my opinion, a decision that corrects the errors identified in each of the expert reports – either separately or in combination – would result in a materially preferable designated NGO decision, because it is more likely to promote the long term interests of consumers to a materially greater degree without compromising the short term interests of consumers, as compared with the decision made by the AER in its Guideline and recent decisions.."*[79]

AGN is confident that its proposed rate of return of 7.23% per annum best promotes the ARORO, NGO and the achievement of the RPP. Our proposed rate of return is set out in Table 10.3. AGN will update these estimates prior to the commencement of the next AA period using the actual averaging period set out in (confidential) Attachment 10.24. The return on debt will also be updated in each year of the next AA period.

TABLE 10.3: PROPOSED RATE OF RETURN

Parameters	AGN Proposal
Return on Equity	9.91%
Return on Debt	5.44%
Leverage	60%
Nominal Vanilla Rate of Return	7.23%

79 Houston Kemp 2015, "*Australian Gas Networks - AER Gas Price Review*", June 2015, pg.45. Provided as Attachment 1.6 to this AAI.

11 Cost of Tax

Page intentionally left blank

11 Cost of Tax

11.1 Introduction

The benchmark total revenue set by the Australian Energy Regulator (AER) must include an allowance for the tax liability (or cost of tax) of the distributor over an Access Arrangement (AA) period. There are two approaches that can be used to determine the benchmark cost of tax for the distributor. The first is by applying a pre-tax regulatory framework to determine total revenue while the second is to adopt a post-tax framework.

The pre-tax approach incorporates the cost of tax directly into the rate of return (or weighted average cost of capital, WACC) used to determine the return on assets component (or building block) of total revenue (all of the building blocks used to determine total revenue are set out in Chapter 13). The post-tax approach involves including as a separate building block a specific forecast of the tax liability of the distributor (and excluding tax from the determination of the WACC).

The AER has expressed a strong preference towards a post-tax approach on the basis that it "*is superior in that it facilitates an accurate allowance for tax in setting regulatory revenues*".[80] Consistent with both the AER preference and the approach applied for the current (2010/11 to 2015/16) AA period, Australian Gas Networks Limited (AGN) has again applied the post-tax approach to determine the cost of tax component of total revenue.

This chapter describes how AGN has determined the benchmark cost of tax to apply over the next (2016/17 to 2020/21) AA period. This includes a discussion on the appropriate value of imputation credits (or gamma) that has been used in calculating the benchmark cost of tax for the next AA period.

11.2 Requirements of the National Gas Rules

The National Gas Rules (NGR) provides the overarching framework for determining the benchmark cost of tax component of total revenue. Rule 72(1)(h) requires that:

> *"The access arrangement information for a full access arrangement proposal (other than an access arrangement variation proposal) must include.... the estimated cost of corporate income tax calculated in accordance with Rule 87A, including the proposed value of imputation credits referred to in that rule…"*

Rule 76(c) provides that:

> *"Total revenue is to be determined for each regulatory year of the access arrangement period using the building block approach in which the building blocks are:*
>
> *…*
>
> *the estimated cost of corporate income tax for the year (see Division 5A)."*

Rule 87A(1) of Division 5A specifies the following manner by which the cost of tax is to be estimated:

> *"The estimated cost of corporate income tax of a service provider for each regulatory year of an access arrangement period (ETC_t) is to be estimated in accordance with the following formula:*
>
> $ETC_t = (ETI_t \times r_t)(1 - \gamma)$

80 AER 2007, "*Electricity Distribution Network Service Providers Transition of Energy Businesses from Pre-tax to Post-tax Regulation, Issues Paper*", June 2007, pg. 51.

Where:

ETI_t is an estimate of the taxable income for that regulatory year that would be earned by a benchmark efficient entity as a result of the provision of reference services if such an entity, rather than the service provider, operated the business of the service provider;

r_t is the expected statutory income tax rate for that regulatory year as determined by the AER; and

γ is the value of imputation credits."

Rule 87(4)(b) also requires the allowed rate of return to be determined on a nominal vanilla basis that is consistent with the estimate of the value of imputation credits referred to in Rule 87A.

Also relevant is Rule 74(2), which states that:

"A forecast or estimate:

(a) Must be arrived at on a reasonable basis; and

(b) Must represent the best forecast or estimate possible in the circumstances."

11.3 Calculating the Cost of Tax

AGN has determined the estimated (or benchmark) cost of corporate income tax (ETC) for each year of the next AA period in accordance with the formula set out in Rule 87A(1) of the NGR.

ETI in the above formula is calculated as total revenue (excluding the cost of tax) less operating expenditure, tax depreciation and interest expense; where:

- total revenue is the sum of all building blocks aside from the cost of tax (see Chapter 13);
- operating expenditure is a specific building block that is used to determine total revenue (see Chapters 7 and 13);
- tax depreciation is based on the calculation of the tax asset base in any particular year (see Section 11.4); and
- interest expense is determined by multiplying the benchmark cost of debt (of 5.44%) by 60% of the regulatory asset base (RAB) in each year (i.e. the debt funded proportion of the total RAB). The cost of debt and the RAB are set out in Chapters 9 and 10 respectively.

The r_t is set at 30% consistent with the prevailing corporate tax rate applying in Australia. The value of imputation credits (γ 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 used by AGN to determine the cost of tax is explained in Section 11.5.

11.4 Adjusting the Tax Asset Base

Determining the amount of tax depreciation to include in calculating the ETI requires AGN to determine the tax asset base (TAB) in each year of the next AA period. This requires the forecast TAB set by the AER for the current AA period to be adjusted for actual/estimated information (see Section 11.4.1). This results in an opening TAB as at 1 July 2016, which is then adjusted for forecast capital expenditure (capex), disposals and tax depreciation over the next AA period (see Section 11.4.2).

11.4.1 Adjusting the TAB over the Current Access Arrangement Period

AGN was required to set the opening TAB for the start of the current AA period as part of the process for transitioning to the post-tax regulatory framework preferred by the AER. AGN relied on both statutory and regulatory information for the purpose of determining the capex and disposals for inclusion in the TAB. As part of this process, the AER approved an opening TAB as at 1 July 2010 of $244 million.[81] This was then adjusted by the AER for forecast information over the current AA period.

AGN has now adjusted the opening TAB as at 1 July 2010 for actual/estimated capex incurred through to 30 June 2016 using the same information as that used to adjust the RAB over the current AA period (as explained in Section 4.3 of this AAI). The opening TAB has also been adjusted for actual tax depreciation over the current AA period (there were no disposals). The adjustments made to the TAB are set out in Table 11.1.

TABLE 11.1: TAX ASSET BASE ROLL FORWARD, 2010/11 TO 2015/16

$ million nominal	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16
Opening Tax Asset Base	243.8	269.2	309.5	372.8	448.1	523.7
Add Gross Capital Expenditure	39.1	55.8	81.5	98.4	104.6	128.5
Less Tax Depreciation	13.7	15.4	18.3	23.0	29.0	36.6
Closing Tax Asset Base	**269.2**	**309.5**	**372.8**	**448.1**	**523.7**	**615.6**

Note: Totals may not add due to rounding.

11.4.2 Forecasting the TAB over the Next Access Arrangement Period

The opening TAB of $616 million ($ nominal) as at 1 July 2016 has been adjusted for forecast information over the next AA period. Again, the forecast information is consistent with that used to adjust the RAB over the next AA period (see Chapter 9).[82] The depreciation methods and lives used to determine tax depreciation from 1 July 2016 are set out in Table 11.2.

TABLE 11.2: TAX DEPRECIATION METHODS AND LIVES

Asset Category	Tax Depreciation Life	Method
Mains	20	Straight line
Inlets	20	Straight line
Meters	15	Straight line
Telemetry	10	Straight line
Information Technology System	4	Straight line
Other Distribution System Equipment	20	Straight line
Other	10	Straight line

The tax depreciation methods and lives applied to capital expenditure are the same as that approved by the AER and applied by AGN for the current AA period. At this time AGN had its methodology reviewed by PricewaterhouseCoopers (PwC) who found that:

> *"the method that has been applied by Envestra is consistent with the decisions that are available to a business under Federal tax law and that the simplifications that Envestra has made are consistent with how the AER has undertaken similar calculations for other*

[81] AER 2011, "*Envestra Ltd: Access Arrangement Proposal for the SA gas network, 1 July 2011 – 30 June 2016*", Final Decision, June 2011, pg. 60.

[82] AGN notes that gross capital expenditure is included in the TAB and net expenditure is included in the RAB. The difference in the capital expenditure used to adjust the TAB and the RAB therefore reflects customer contributions.

> *regulated businesses. We therefore conclude that Envestra's approach is consistent with the AER's requirements."*[83]

In accepting this approach, the AER in its Draft Decision for South Australia stated:

> *"The AER has reviewed the tax asset lives and finds no issue with the tax asset lives as proposed by Envestra [AGN]. The standard tax lives proposed by Envestra are consistent with the requirements of the Income Tax Assessment Act 1997. From 1 July 2002, the effective lives of gas distribution assets became subject to a statutory cap of 20 years. Envestra's proposed standard tax asset lives are consistent with these caps. Therefore, the AER accepts the standard tax asset lives proposed by Envestra."*[84]

This decision was carried through to the AER's Final Decision for Envestra's [AGN's] South Australian network. AGN is not aware of any changes to relevant tax law since PwC gave its advice to AGN in September 2010, nor since the AER made the previous South Australian Final Decision, which was released in July 2011. The proposed approach to calculating tax depreciation is therefore consistent with the relevant tax law and previous decisions made by the AER.

The resultant roll-forward of the TAB over the next AA period is shown in Table 11.3.

TABLE 11.3: TAX ASSET BASE ROLL FORWARD, 2016/17 TO 2020/21

$ million nominal	2016/17	2017/18	2018/19	2019/20	2020/21
Opening Tax Asset Base	615.6	714.8	822.2	916.7	1,005.5
Add Gross Capital Expenditure	142.1	160.0	155.0	158.7	146.9
Less Tax Depreciation	42.8	52.6	60.4	70.0	80.3
Closing Tax Asset Base	**714.8**	**822.2**	**916.7**	**1,005.5**	**1,072.1**

Note: Totals may not add due to rounding.

11.5 Value of Imputation Credits (γ or Gamma)

Under Australia's dividend imputation tax system, dividends that are paid out of company profits that have been taxed in Australia have imputation credits attached to them. A proportion of those credits will be redeemed against the domestic personal tax obligations of shareholders who receive them. However, credits distributed to non-resident shareholders cannot be redeemed. Further, not all credits distributed to resident shareholders are in fact redeemed.[85]

The NGR provide for the value of imputation credits to be taken into account in estimating the cost of corporate income tax building block. As noted in Section 11.2, gamma (γ) is the factor used to adjust the estimate of the taxable income of the benchmark efficient entity (ETI) for the value attributed to imputation credits. The effect of Rule 87A is to reduce the cost of tax building block to take account of the value equity holders place on imputation credits, reducing the required return to those equity holders.

AGN proposes a value of imputation credits (or gamma) of 0.25 for the next AA period. This section summarises our approach to estimating the value of imputation credits (a more detailed explanation is set out in Attachment 11.2).

---

83 PwC 2010, "*Post Tax Revenue Model Methodology – Review of Initial Taxation Asset Base*", September 2010, pg. 2. Provided as Attachment 11.1 to this AAI.

84 AER 2011, "*Envestra Ltd: Access Arrangement Proposal for the SA gas network, 1 July 2011 – 30 June 2016*", Draft Decision, February 2011, pg. 105-106.

85 SFG 2015, "*Estimating Gamma for Regulatory Purposes*", February 2015, paragraph 23.

11.5.1 Changes to the National Gas Rules in 2012

Rule 87A was inserted into the NGR as part of the suite of changes made by the Australian Energy Market Commission (AEMC) to the NGR in 2012 (referred to as the 2012 rule changes). As noted in Chapter 1, the AER is required to make a decision on gamma that reflects the best estimate and that best promotes the National Gas Objective (NGO) and, in exercising discretion, takes into account the Revenue and Pricing Principles (RPP).

Prior to the 2012 rule changes and the related insertion of Rule 87A, the NGR did not include a definition of gamma. The National Electricity Rules, however, included a definition of gamma in the formula for the estimated cost of corporate income tax, being "*the assumed utilisation of imputation credits*."[86] The AER historically took the same approach to estimating gamma for both electricity and gas businesses, which determined the value of imputation credits by calculating the product of:

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

Following a decision made by the Australian Competition Tribunal (the Tribunal),[87] this approach resulted in an estimate of the utilisation rate of 0.35 (based on the SFG 2011 "*state of the art*" dividend-drop-off study that was initiated by the Tribunal) and a distribution rate of 0.70, which gave rise to a value for imputation credits of 0.25. This value for imputation credits of 0.25 was applied by the AER in all subsequent decisions up until the development of its Rate of Return Guideline.[88]

AGN considers that Rule 87A was included in the NGR to clarify and embody the (then) existing regulatory approach to the estimation of gamma by defining gamma as the "value" as in “worth” of imputation credits to equity holders. In contrast to its decision on the rate of return, this reflects that the AEMC made no comment in its decision that it was concerned with the regulatory approach that had developed to estimate gamma or the Tribunal decisions in respect of it.

11.5.2 AER Rate of Return Guidelines

The AER’s Rate of Return Guideline proposed an estimate of gamma of 0.5. The AER departed from this estimate in its 2015 decisions and now proposes an estimate of 0.4, from within a range of 0.3 to 0.5.

This section explains AGN’s approach to estimating gamma and identifies where the proposal departs from the AER Rate of Return Guideline and 2015 decisions.[89]

11.5.3 Distribution Rate

The distribution rate is a measure of the proportion of a firm’s earnings that it returns to shareholders versus the earnings it retains. It is accepted that the distribution rate is a firm-specific parameter. Different firms will have different capital requirements and patterns for earnings.

AGN proposes a distribution rate of 0.7 derived from a market-wide sample (listed and unlisted equity) of Australian firms using data from the Australian Tax Office (ATO). This distribution rate reflects the methodology and estimate of the distribution rate endorsed by the Tribunal. AGN considers that this estimate, based on a market-wide distribution rate, remains the best estimate for the following key reasons:

---

86 Previous NER 6.5.3.

87 Application by Energex Limited ((Gamma) No 5) [2011] ACompT9.

88 The AER was required under the 2012 rule changes to develop a (non-binding) Rate of Return Guideline outlining the approach it intends to take in setting the rate of return.

89 The AER has recently published Final Decisions in respect of TransGrid, Ausgrid, Endeavour Energy and Essential Energy, ActewAGL, TasNetworks, Directlink and Jemena Gas Networks (JGN) and Preliminary decisions for Energex, Ergon Energy and SA Power Networks.

- this estimate is consistent with the definition set out in the AER Guideline of a benchmark efficient firm being "*a pure play, regulated energy network business operating within Australia*". That is, the AER's benchmark is not restricted to listed entities;
- a distribution rate derived from listed equity only is skewed by the top 20, predominantly multinational, listed entities, which are inappropriate comparators;
- when the top 20 firms are ‘backed out’ of the listed equity data, the distribution rate is in any event consistent with 70%;
- as the distribution rate is a firm-specific parameter, the best estimate will be derived from a market-wide sample; and
- there are sufficient data available for both listed and unlisted entities, and in those circumstances, a better estimate of the distribution rate will be derived from the use of a market wide estimate.

11.5.4 Utilisation Rate (or Theta)

The utilisation rate represents the value to investors of distributed imputation credits. Unlike the distribution rate, this is not a firm-specific parameter. AGN considers that the only approach that provides an estimate of the ‘value’, as in worth, of distributed imputation credits to equity investors is to estimate theta using market value studies. These studies provide direct evidence of the market value of distributed credits.

The Tribunal has previously accepted SFG's March 2011 dividend drop-off study as "*The best dividend drop-off study currently available for the purpose of estimating gamma in terms of the Rules*".[90] That study has been updated by SFG Consulting and, in the opinion of SFG, the best estimate of the utilisation rate remains 0.35.

Estimating the utilisation rate on the basis of market value studies recognises that equity investors do not value imputation credits at their full face value. There are various reason for this, including the 45 day tax rule that reduces eligibility of investors to redeem imputation credits and transaction costs associated with the redemption of imputation credits. It follows that estimates derived from other sources, such as redemption rates, can only reflect an upper bound estimate of theta.[91]

SFG’s 2011 dividend-drop-off study (updated) remains the best available market value study from which to estimate the value of distributed credits. In AGN’s submission, there is no basis to depart from the estimate of the utilisation rate endorsed by the Tribunal and confirmed as the current best estimate by SFG Consulting.

11.5.5 Departure from the Rate of Return Guidelines

AGN’s proposed approach to gamma departs from the Guidelines and the AER 2015 decisions in that AGN’s proposed estimate of gamma is 0.25, compared to the AER’s estimate of 0.4 in its 2015 decisions (0.5 in its earlier Guideline). The difference is driven by:

- AGNs proposed distribution rate of 0.7 based on a market-wide estimate derived from Australian Tax Office data, instead of the AER’s estimate based on the range of 0.70 to 0.77 (derived by separating estimates for all equity and listed equity only); and

---

90 Application by Energex Limited (Gamma) (No 5) [2011] A CompT 9, paragraph 29.

91 This is because redemption rates only identify the proportion of Australian equity owned by resident investors. To say anything about the value of the utilisation rate, it would need to be assumed that domestic investors would all be eligible to redeem imputation credits and that those investors value those imputation credits at their full face value. In AGN’s submissions, these assumptions are incorrect.

- AGN's proposed utilisation rate of 0.35 based on the SFG 2011 dividend-drop-off study (updated), instead of the AER's utilisation rate derived primarily from the equity ownership approach (giving rise to a redemption rate estimate, resulting in an (implied) estimate of 0.6).

The detailed reasons for AGN's departure from the Rate of Return Guidelines and 2015 decisions is set out in Attachment 11.2.

11.5.6 Summary

The estimate of the value of imputation credits must be consistent with the value placed on imputation credits by equity holders. If not, the resulting estimate of corporate income tax will not allow AGN to recover at least its efficient costs (required to be taken into account by the RPP), which includes a return to equity holders (thereby leading to investment that is not consistent with the NGO).

AGN's proposal is based on the advice of independent experts that the value of imputation credits should be estimated using the product of:

- a distribution rate of 0.7; and
- a utilisation rate of 0.35 on the basis of the SFG dividend-drop-off study endorsed by the Tribunal (updated);
- giving rise to an estimate of gamma of 0.25.

These estimates of the utilisation rate and the distribution rate are the best estimates available.[92] These estimates are also consistent with an estimate of the worth of imputation credits to equity holders, which AGN considers is consistent with the correct interpretation of Rule 87A.

AGN has also sought independent expert advice from Dr Greg Houston of HoustonKemp Economists in relation to our proposed approach to the value of imputation credits, including whether it is materially preferable in making a contribution to the NGO, having regard to the AER's approach set out in its Guideline and 2015 decisions.

Dr Houston has considered the various expert reports on which AGN relies in respect of its gamma proposal and concludes that a decision that corrects the errors identified in those reports would result in a materially preferable designated NGO decision. This is because AGN's proposed approach is more likely to promote the long-term interests of consumers to a materially greater degree without compromising the short-term interests of consumers, as compared with the AER in its Guideline and 2015 decisions.[93]

11.6 Tax Losses Carried Forward

The AER requires that AGN determine whether there will be any tax losses as at 1 July 2016. This is because any such tax losses would need to be carried forward into the next AA period to offset any future tax liabilities that might arise.

AGN confirms that there are no tax losses from the current AA period that need to be factored into determining the benchmark tax liability for the next AA period (this is also consistent with the AER Final Decision for the current AA period).

11.7 Calculating the Cost of Tax

The benchmark cost of tax calculation, applying the approach and parameters explained in this chapter, is shown in Table 11.4.

---

92 SFG 2015, "*Estimating Gamma for Regulatory Purposes*", February 2015, paragraph 22.

93 Houston Kemp 2015 "*Australian Gas Networks AER Gas Price Review*", June 2015, pg. 45.

TABLE 11.4: BENCHMARK COST OF TAX CALCULATION, 2016/17 TO 2020/21

$ million nominal	2016/17	2017/18	2018/19	2019/20	2020/21
Total Revenue	203.2	208.7	229.4	249.4	258.4
Less Opex	71.6	75.8	79.8	82.2	85.2
Less Depreciation	42.8	52.6	60.4	70.0	80.3
Less Interest	46.6	51.0	55.9	60.4	64.9
Less Tax Losses Carried Forward	0.0	0.0	0.0	0.0	0.0
Taxable Income	42.1	29.2	33.2	36.9	28.0
Tax Payable	12.6	8.8	10.0	11.1	8.4
Value of Imputation Credits	3.2	2.2	2.5	2.8	2.1
Benchmark Cost of Tax	9.5	6.6	7.5	8.3	6.3

12 Incentive Arrangements

Australian Gas Networks

Page intentionally left blank

12 Incentive Arrangements

12.1 Introduction

This chapter describes the outcomes arising from the application of the Efficiency Benefit Sharing Scheme (EBSS) that applied to operating expenditure (opex) over the current (2011/2012 to 2015/2016) Access Arrangement (AA) period. The amount derived under the EBSS gives rise to an additional 'building block' in the calculation of the Total Revenue that Australian Gas Networks Limited (AGN) can recover over the next (2016/2017 to 2020/2021) AA period (see Chapter 13 for the derivation of Total Revenue).

AGN is a strong supporter of effective, outcome-based incentive arrangements as a way of promoting the long-term interests of consumers (and therefore better promoting the National Gas Objective (NGO) which is set out in Chapter 1 of this Access Arrangement Information (AAI). AGN is proposing to strengthen the existing incentives and introduce new incentive arrangements to apply to the business over the next AA period.

This chapter explains the changes to the incentive arrangements that AGN is proposing to apply over the next AA period. This includes strengthening the financial incentives attached to the EBSS, the introduction of a Capital Efficiency Sharing Scheme (CESS) and the application of a new scheme that encourages AGN to invest in innovation over the next AA period. AGN is also proposing to introduce an incentive scheme that promotes improvements in customer service during the next AA period.

AGN considers these arrangements will promote improvements in network performance, and as such, are in the long-term interests of customers as required by the NGO.

12.2 Requirements of the National Gas Rules

Rule 98 of the National Gas Rules (NGR) states that:

> *"(1) A full access arrangement may include (and the AER [Australian Energy Regulator] may require it to include) one or more incentive mechanisms to encourage efficiency in the provision of services by the service provider.*
>
> *(2) An incentive mechanism may provide for carrying over increments for efficiency gains and decrements for losses of efficiency from one access arrangement period to the next.*
>
> *(3) An incentive mechanism must be consistent with the revenue and pricing principles."*

The revenue and pricing principles are set out in Section 24 of the National Gas Law (NGL) and repeated in Chapter 1 of this Access Arrangement Information (AAI). The most relevant revenue and pricing principles for the purposes of setting appropriate incentives arrangements include:

> *"• A service provider should be provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs in -*
>
> > *(a) providing reference services; and*
> >
> > *(b) complying with a regulatory obligation or requirement or making a regulatory payment.* [94]
>
> *• A service provider should be provided with effective incentives in order to promote economic efficiency with respect to reference services the service provider provides. The economic efficiency that should be promoted include -*

[94] National Gas Law, Section 24(2).

(a) efficient investment in, or in connection with, a pipeline with which the service provider provides reference services; and

(b) the efficient provision of pipeline services; and

(c) the efficient use of the pipeline.[95]

- *A reference tariff should allow for a return commensurate with the regulatory and commercial risks involved in providing the reference service to which that tariff relates.*[96]
- *Regard should be had to the economic costs and risks of the potential for under and over investment by a service provider in a pipeline with which the service provider provides pipeline services.* [97]"

12.3 Requirements of the Access Arrangement

Section 5.1 of the current South Australian AA Document sets out the manner by which the EBSS, which scheme was designed by the Australian Energy Regulator (AER), is to be applied over the current AA period. Specifically, Section 5.1 states:

"The principles of the incentive mechanism are:

- *Only an operating expenditure incentive mechanism should apply;*
- *For the first year of [the] access arrangement period commencing on 1 July 2011, the operating expenditure annual efficiency gain (or loss) will be calculated as:*

  $E_1 = F_1 - A_1$

  where:

  F_1 *= the forecast Opex in year one of the access arrangement period*

  A_1 *= the actual Opex in year one of the access arrangement period*

- *The operating expenditure annual efficiency gain (or loss) in the second, third and fourth year[s] of the access arrangement period will be calculated as:*

  $E_i = (F_i - A_i) - (F_{i-1} - A_{i-1})$

  where:

  E_i *is the efficiency gain in year i of the access arrangement period*

  F_i *is the forecast opex in year i of the access arrangement period*

  A_i *is the actual opex in year i of the access arrangement period*

- *The operating expenditure annual efficiency gain (or loss) in the last year of the access arrangement period will be estimated as follows:*

  $A_5^* = F_5 - (F_4 - A_4)$

  where:

  A_5^* *is the estimate of Opex for the final year of the access arrangement period*

  F_5 *is the forecast Opex for the final year of the access arrangement period*

  F_4 *is the forecast Opex for the penultimate year of the access arrangement period*

  A_4 *is the actual Opex for the penultimate year of the access arrangement period*

95 National Gas Law, Section 24(3).

96 National Gas Law, Section 24(5).

97 National Gas Law, Section 24(6).

- *Carryover amounts for the final year of the access arrangement period are to be estimated using the following equation:*

  $E_5 = (F_5 - A_5^*) - (F_4 - A_4)$

  Where:

  E_5 *is the efficiency gain for the final year of the access arrangement period*

  F_5 *is the forecast Opex for the final year of the access arrangement period*

  A_5^* *is the estimate of Opex for the final year of the access arrangement period*

  F_4 *is the forecast Opex for the penultimate year of the access arrangement period*

  A_4 *is the actual Opex for the penultimate year of the access arrangement period*

- *Carryover amounts for the first year of the access arrangement period commencing 1 July 2016 are to be estimated using the following equation:*

  $E_6 = (F_6 - A_6) - (F_5 - A_5) + (F_4 - A_4)$

  Where:

  E_6 *is the efficiency gain in the first year of the access arrangement period*

  F_6 *is the forecast Opex for the first year of the next access arrangement period*

  A_5 *is the actual Opex for the first year of the next access arrangement period*

  F_5 *is the forecast Opex for the final year of the access arrangement period*

  A_5 *is the actual Opex for the final year of the access arrangement period*

  F_4 *is the forecast Opex for the fourth year of the access arrangement period*

  A_4 *is the actual Opex for the fourth year of the access arrangement period*

- *The positive carryover that would result in Envestra [AGN] retaining the reward associated with an efficiency improving initiative for five years after the year in which the gain was achieved, ie. A reward earned in one year of an Access Arrangement Period would be added to the Total Revenue and carried forward into the Fourth Access Arrangement period if necessary, until it had been retained by Envestra for a period of five years. Similarly, the negative carryover that would result in Envestra retaining the penalty associated with the inefficiencies for five years after the year in which the penalty was incurred, ie. a penalty incurred in one year of an Access Arrangement Period would be subtracted from the Total Revenue and carried forward into the Fourth Access Arrangement Period if necessary, until it has been retained by Envestra for a period of five years.*

- *Operating expenditure efficiencies achieved or inefficiencies incurred in accordance with the approved incentive mechanism in the Access Arrangement Period will give rise to an additional 'building block' in the calculation of the Total Revenue amounts.*

- *The costs associated with an impost or complying with any retailer of last resort requirements will be excluded from the operation of the efficiency carryover mechanism. Further, the following costs will also be excluded from the operation of the efficiency carryover mechanism:*

  - *amounts for approved cost pass through events*
  - *debt raising costs*
  - *insurance costs*
  - *superannuation costs for defined benefits and retirement schemes*
  - *other specific uncontrollable costs incurred and reported by Envestra during the access arrangement period, which the AER considers should be excluded in accordance with the NGL and NGR.*

- *Any other activity that Envestra and the Regulator agree to exclude from the operation of the efficiency carryover mechanism will be so excluded.*
- *For the avoidance of doubt, the forecast expenditure amounts that are used as the basis for measuring efficiencies relate to the expenditure benchmarks approved by the Regulator, with the following exception:*
  - *the carryover of cost related efficiency gains will be calculated in a manner that takes account of any change in the scope of activities which form the basis of the determination of the original benchmarks, but only where the scope of changes arise from exogenous factors and where they impose material additional costs to Envestra. Any adjustment will be made following the provision of relevant information to the Regulator and the assessment of that information by the regulator and will, without limitation, quantify and substantiate the impact of the changes on the original benchmarks.*
- *Where Envestra changes its approach to classifying costs as either Capex [capital expenditure] or Opex during the access arrangement period, Envestra will adjust the forecast Opex used to calculate the carryover amounts so that the forecast expenditures are consistent with the capitalisation changes.*
- *If there is a change in Envestra's approach to classifying costs as either Capex or Opex, Envestra must provide the AER a detailed description of the change and a calculation of its impact on forecast and actual Opex."*

12.4 EBSS Outcomes for the Current Access Arrangement Period

The EBSS that is in place for the current AA period applies to opex only. As explained in this section, AGN has applied the EBSS in a manner that is consistent with the principles set out in Section 5.1 of the current AA Document (as provided in Section 12.3).

Section 5.1 of the current AA Document provides for AGN to retain for a period of five years any benefit (or loss) associated with an efficiency gain (or loss). The efficiency gain or loss is calculated as the difference between the under or over spend in opex in the relevant year and the under or over spend in opex in the previous year (that is, the EBSS captures incremental improvements in efficiency). The under or over spend in opex is determined by taking the difference between benchmark and actual opex in a particular year.

Section 5.1 of the current AA Document allows the AER to approve changes in the benchmark opex used to determine the opex under or over spend to reflect material changes in the scope of activities provided by AGN over the current AA period. AGN has not sought any such adjustments to the benchmarks.

There is also scope for the AER to exclude from the operation of the EBSS certain defined costs/events and/or any other activity agreed to with AGN. AGN has removed from the 2014/15 year $0.7 million incurred as a result of the failure on the transmission pipeline (not owned by AGN) supplying Whyalla and Port Pirie. AGN considers these costs to be "*other specific uncontrollable costs*" as they were incurred as a result of a one off event on a third-party owned asset.

Table 12.1 provides an extract from the AGN Post-tax Revenue Model (PTRM) that was used for calculating the opex efficiency carry over amounts to apply over the next AA period. This shows that AGN has made significant efficiency gains over the current AA period, which has led to a net positive carryover amount of $6 million to apply in the next AA period. This amount is added to our Total Revenue for the next AA period.

TABLE 12.1: DETERMINATION OF OPEX EFFICIENCY CARRYOVER AMOUNTS

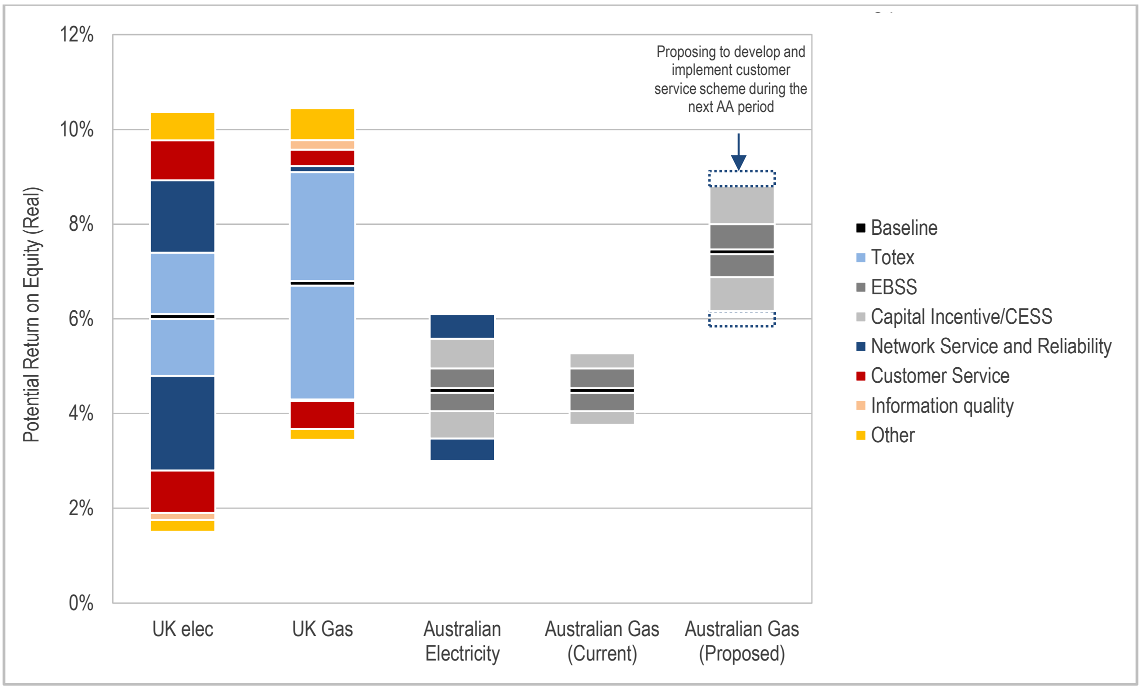
	Current AA Period					Next AA Period				
	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Opex Benchmark										
$ million real 2010/11	68.6	67.5	66.8	65.3	62.9	–	–	–	–	–
$ million real 2015/16	77.0	75.7	74.9	73.3	70.6	–	–	–	–	–
Opex Actual										
Money of the day	62.9	62.6	66.5	65.2	–	–	–	–	–	–
$ million real 2015/16	68.3	66.9	69.4	66.1	63.4	–	–	–	–	–
Opex Underspend ($ million real 2015/16)	8.6	8.8	5.6	7.2	7.2	–	–	–	–	–
Opex Incremental Gain ($ million real 2015/16)	8.6	0.2	(3.2)	1.6	–	–	–	–	–	–
Carry-Over										
Year 2016/17	–	8.6	8.6	8.6	8.6	8.6	–	–	–	–
Year 2017/18	–	–	0.2	0.2	0.2	0.2	0.2	–	–	–
Year 2018/19	–	–	–	(3.2)	(3.2)	(3.2)	(3.2)	(3.2)	–	–
Year 2019/20	–	–	–	–	1.6	1.6	1.6	1.6	1.6	–
Year 2020/21	–	–	–	–	–	–	–	–	–	–
Opex Efficiency Carry-Over ($ million real 2015/16)	–	–	–	–	–	**7.2**	**(1.5)**	**(1.6)**	**1.6**	–

12.5 Proposed Incentive Mechanisms for the Next Access Arrangement Period

AGN considers that the NGO and the Revenue and Pricing Principles will be best achieved by enhancing the incentive arrangements that are to apply over the next AA period. This reflects that the current incentives that apply to the business to improve performance are low, compared to that available to electricity businesses in Australia and electricity and gas businesses in the United Kingdom (UK).

By way of example, AGN estimates that a gas business in the UK could potentially increase (or decrease) its return on equity by over 3% if it outperforms (or underperforms) against certain performance targets, whereas the maximum incentive available to similar businesses in Australia is less than 1% (see Figure 12.1).

FIGURE 12.1: ECONOMIC INCENTIVE SCHEMES – COMPARISON TO AUSTRALIAN GAS REGULATION



AGN is proposing that the following incentive arrangements apply from 1 July 2016:

- the retention of the AER's EBSS, albeit modified to strengthen the financial incentive to improve opex efficiency;
- the introduction of the AER's Capital Expenditure Sharing Scheme (CESS), also modified to strengthen the financial incentives to improve capital expenditure (capex) efficiency; and
- the introduction of a scheme to promote lower cost and/or improved service delivery outcomes through innovation.

With regard to the EBSS and CESS, AGN believes that the power of the incentive should be strengthened such that any efficiency gain or loss is shared equally by consumers and the business (i.e. a 50:50 efficiency sharing ratio). We have therefore proposed to modify the schemes that are currently applied by the AER to implement this sharing ratio. AGN has also sought to limit the potential for windfall gains or losses to arise under both schemes.

AGN considers, consistent with our stakeholder feedback (see Chapter 3), that the incentive arrangements to apply over the next AA period should also include appropriate incentives to improve customer service. We recognise, however, that there are limitations on such a scheme being introduced at the start of the next AA period, namely due to constraints relating to the availability of data and the need for additional stakeholder consultation.

Our intention therefore is to continue to engage with stakeholders, including the AER, to ensure any incentives to improve customer service best reflect customer values and provide a meaningful incentive on the business to improve performance. As a result, we are proposing that a customer service incentive scheme be introduced during the next AA period, commencing on 1 July 2017.

The remainder of this section explains in more detail the proposed incentive schemes for the next AA period.

12.5.1 Retention of the Efficiency Benefit Sharing Scheme

The EBSS currently applies to all of our regulated networks. The EBSS is a well-designed scheme that provides ongoing and continuous incentives to improve opex efficiency in any year of the regulatory period.

The current EBSS allows AGN to retain the benefit of an efficiency gain (or loss) for a five-year period regardless of when that efficiency gain (or loss) is achieved. This is equivalent to AGN retaining 30% of the efficiency gain (or loss) and customers receiving the remaining 70%.

While we intend to retain the EBSS in the next AA period, we note that:

- the power of the EBSS is low relative to other similar schemes (such as the total expenditure incentive scheme in the UK that allows for 65% of the efficiency to be retained by the business) for gas[98] and up to 70% for electricity distribution[99]; and
- as the industry matures and privately-owned business such as AGN improve in terms of productivity, it becomes more difficult to achieve further productivity gains; in light of this, it is appropriate that incentive mechanisms are strengthened in order to ensure that businesses remain adequately incentivised to continue to strive for additional efficiency gains.

These issues are discussed in more detail in this section.

12.5.1.1 The Power of the Incentive

AGN appreciates that the incentive power of a scheme such as the EBSS or the CESS cannot be chosen with precision and instead requires some judgement. This was recognised by the Office of the Regulator General of Victoria (ORG) when it was designing one of the first incentive schemes applied in Australia. The ORG recognised that the sharing ratio depends, amongst other things, on the responsiveness of the businesses to changes in the share of efficiency gains they retain, stating:

> *"There is no predetermined "optimal" sharing of gains. The optimal relationship between gains retained and efficiencies achieved depends on the underlying assumptions regarding the responsiveness of the regulated businesses (in terms of cost reduction and innovation) to changes in the share of efficiency gains they retain. Importantly, the "optimal" sharing ratio also depends on considerations of allocative as well as productive efficiency."*[100]

This is a view that is also shared by Ofgem in the UK, which noted that incentive rates will (or should) vary across companies and that there is no exact science to determining optimal incentive rates. Ofgem also noted in this context that it is important that incentive rates not be set too low:

> *"…There is no exact science to determining 'optimal' efficiency incentive rates and there are a number of issues to consider when determining the appropriate rates. We discuss the factors that should be considered below. For simplicity, we talk about factors affecting the appropriate level of the efficiency incentive rate, although in practice we will be deciding on a range (e.g. 40 to 50 per cent)...*[101]
>
> *We will undertake preliminary analysis to determine a lower bound for the incentive rate. The range of efficiency incentive rate will not be below this lower bound, but it could be above it (e.g. we might decide that the lower bound is 30 per cent, but set a range of efficiency incentive rates of 40 to 50 per cent). It is important that the lower bound is set appropriately as if the incentive rate is set too low, a company may not face exposure to the*

---

98 Ofgem 2012, "*RIIO-GD1: Final Proposals - Supporting Document - Cost Efficiency*", December 2012, pg. 61.

99 Ofgem 2014, "*Decision to Fast-track Western Power Distribution*", February 2014, pg. 11.

100 Office of the Regulator General, Victoria, 2000, "*Electricity Distribution Price Determination, 2001-2005, Volume 1, Statement of Purpose and Reasons*", September 2000, pg.91-92.

101 The IQI mechanism referred to in this quote is an additional incentive on businesses to forecast efficiently. The mechanism determines the specific incentive rate within the range of incentive rates that can be applied to businesses in the UK. Under the IQI businesses are provided with a menu of choices (and get to nominate their expenditure forecast). The choice offered is that the lower is the business's capital expenditure forecast compared to the regulator's baseline, the higher the incentive rate within the range that is applied. The matrix of choices is structured such that the businesses always optimise by putting in their most efficient forecast of expenditure.

> *costs that result from overspend and could spend money unnecessarily to increase its regulatory asset value (RAV). This will not be in consumers' interests as explained in more detail [in the Ofgem document]".* [102]

Ofgem in the above extract explains that, if the incentive rate is too low, a business might not have a sufficient incentive to only incur prudent and efficient capex. This is because the penalty the business would receive through the incentive scheme would not be sufficient to offset the benefit the business might otherwise receive by including the additional capex in its regulatory asset base. This is a relevant consideration in deciding on the incentive rate.

It is also relevant to note that the power of our incentive schemes is considerably lower than that applying to electricity and gas businesses in the UK (as per Figure 12.1). For example, the incentive rates for gas businesses in the UK can be as high as 65% (i.e. 65% of an efficiency gain or loss is retained by the business) [103], which rates (even at their lower bound) are significantly more powerful than the equivalent AER schemes that apply in Australia. Ofgem justified its incentive rates indicating that:

> *"We consider that the incentive rates provide a correct balance of incentives for shareholders, as well as benefit (or increased cost) to consumers from any outperformance (underperformance)."* [104]

It is notable that while there is extensive experience with the application of expenditure incentive schemes in Australia, there has not been any change in the power of the incentive schemes from when they were first introduced by regulators around 15 years ago. AGN considers this is inconsistent with what would be expected for privately owned businesses, such as AGN, that have been subject to incentive regulation for an extended period of time.

To this end, the South Australian natural gas distribution network (the Network) has been exposed to incentive regulation since the introduction of the National Gas Code in 1997. AGN has achieved significant productivity improvements over this period, with the South Australian network operating in a manner that is consistent with good industry practice (see Chapter 4).

AGN engaged Economic Insights to measure and compare the productivity performance of the Network (referred to by Economic Insights as AGN SA) with other privately owned gas distribution networks in Victoria, New South Wales and Queensland. Economic Insights noted that:

> *"The pattern of strong productivity growth during the period 1999 to 2008 and relatively flat TFP [Total Factor Productivity] growth after 2008 for AGN SA is common also to the Victorian GDBs [Gas Distribution Businesses] and JGN [Jemena Gas Networks]. The annual average TFP growth rate of AGN SA between 2008 and 2014 of -0.1 per cent can be compared to -0.3 per cent for JGN over the same period, and +0.2 per cent for the Victorian GDBs over the period 2008 to 2011."* [105]

That is, Economic Insights found that all businesses in the sample have achieved moderated productivity growth in more recent years relative to earlier years (say, following the introduction of incentive regulation). Economic Insights in an earlier study for the Victorian gas distributors also noted the slowing of productivity growth rates over recent years. Economic Insights provided the following context around this trend:

---

[102] Ofgem 2010, "*Handbook for Implementing the RIIO model*", October 2010, pg. 84.

[103] All components of the incentive calculation are post-tax.

[104] Ofgem 2012, "*RIIO-GD1: Final Proposals – Supporting Document – Cost Efficiency*", Ref: 168/12, December 2012, pg. 61.

[105] Economic Insights 2015, "*The Productivity Performance of Australian Gas Networks' South Australian Gas Distribution System*", February 2015, pg. ii.

> *"Normally, firms that are at the forefront of industry performance have high productivity levels but low productivity growth rates. This is because they have removed almost all unnecessary slack from their operations and are only able to increase productivity at the rate of technological change for the industry. Conversely, firms that are not operating at high levels of efficiency should be able to achieve higher productivity growth rates as they catch up. As all firms become efficient (eg in response to incentive regulation) then productivity growth rates will converge to the long run rate of technological change in the industry.*
>
> *This process of 'convergence' to the long rate [long-run rate] of technological change in the industry also has important implications for the interpretation of measures of historical TFP [Total Factor Productivity] growth at the industry level for regulatory purposes. In most infrastructure industries we normally see a period of high productivity growth when the reform process is started and easy 'catch-up' gains are made. As performance moves closer to best practice, industry productivity growth usually slows down as marginal improvements become harder to achieve.*
>
> *The rate of technological change in distribution businesses is likely to be relatively slow given the mature and stable nature of the technology used."* [106]

That is, future efficiency gains are expected to be limited to the rate of technological change in the gas distribution sector. AGN considers that this provides strong support for increasing the power of the incentive scheme in order for additional (and more costly) efficiencies to be realised. The result being that, by facilitating increased effort to identify and implement more costly efficiency improvements, prices to consumers will be lower than otherwise would be the case.

AGN is therefore proposing to bring the power of the incentives provided under the EBSS and CESS to be more in line with similar incentive schemes applied by Ofgem in the UK. AGN is proposing that the sharing of any efficiency gain or loss be increased from the current rate of 30% retained by the business to 50%, such that efficiencies are shared equally with consumers. AGN believes that this will facilitate the achievement of further efficiency gains, and as such, better promotes the NGO.

12.5.1.2 Consistent Sharing of Efficiency Gains

When the AER first established the EBSS for electricity distribution businesses it considered the question of the appropriate sharing ratio. At that time the AER identified that its reluctance to strengthen the power of the incentive was largely based on its position to apply the scheme to operating expenditure only. Specifically, when considering the prospect of a 50:50 sharing ratio the AER stated:

> *"The AER considers that the use of multipliers, or a longer carry-over period, in the EBSS would be inappropriate where the EBSS is only applied to opex, as is proposed. With the EBSS not applying to capex, DNSPs [Distribution Network Service Providers] retain approximately 35 per cent of capex reductions in the first year of a regulatory period if actual depreciation is used in the RFM [roll-forward model] (assuming the average life of a new asset is 40 years). This drops to 8 per cent in the final year (again assuming the use of actual depreciation and an average new asset life of 40 years). Consequently, DNSPs would retain significantly more of the benefits of opex efficiency gains as compared to capex efficiency gains if a 50:50 sharing ratio were provided by the opex EBSS. The AER considers the resulting imbalance between the strength of capex and opex incentives to be potentially detrimental to efficiency as it may inappropriately distort the resource allocation decisions of a DNSP."* [107]

---

106 Economic Insights 2012, "*The Total Factor Productivity Performance of Victoria's Gas Distribution Industry*", March 2012, pg. 7.

107 AER 2008, "*Explanatory Statement, Proposed Electricity Distribution Network Service Providers Efficiency Benefits Sharing Scheme*", April 2008, pg. 21.

The expenditure incentives that AGN has proposed for the next AA period are to apply equally to capital and operating expenditure. This approach, as a consequence, removes one of the AER's barriers to a higher powered incentive rate. This is because the proposed introduction of the CESS will result in the same incentives applying to capex as will be applied to opex. The introduction of the CESS therefore facilitates an increase in the sharing ratio for both schemes over the next AA period.

12.5.1.3 Adjustment to the EBSS Mechanism

The current EBSS provides for benefits or losses to be retained for five years following the year in which the efficiency gain or loss was made. The power of the incentive provided by the EBSS is therefore a function of the retention period and the discount rate. This means that the incentive power under the EBSS can be strengthened by increasing the retention period, where a longer period implies a greater incentive rate and vice versa.

AGN does not, however, consider that it is preferable for the power of the incentive for opex to be strengthened via an extension of the retention period. The main reason for this is that, depending on the discount rate assumed, it would require that the business retains benefits or losses for a period of around 10 years. AGN considers that this would overly delay the sharing of efficiency benefits with consumers.

Our preference is to adopt a net present value (NPV) style mechanism similar to the one that applies for capital expenditure under the CESS. This type of mechanism allows for the choice of any sharing ratio to be applied without needing to impact when the benefits of efficiency gains or losses are passed through to consumers. The intention is to ensure that any efficiency gains or losses, in NPV terms, are shared equally between AGN and South Australian consumers.

An NPV-style mechanism for the EBSS has the additional advantage of aligning the way that incentive amounts are calculated for both opex under the EBSS and capex under the CESS.

12.5.2 Introduction of the Capital Expenditure Sharing Scheme

AGN is proposing to introduce the CESS for the next AA period in order to:

- further strengthen the incentive to incur prudent and efficient capex, particularly in light of the relative flat rates of Total Factor Productivity (TFP) growth experienced by all distributors since 2008 (TFP captures growth in both operating and capital expenditure efficiency);
- related to the above (and as discussed in Section 12.5.1.2), facilitate the strengthening of the financial incentives that apply to both opex and capex;
- provide appropriate incentives for the efficient trade-off between capital and operating expenditure:
  - applying a continuous and symmetrical incentive to both capex and opex will strengthen the incentive to ensure that the most appropriate form of expenditure is used;
  - this is because the financial incentive to incur efficient capex is the same as the incentive that applies to opex; and
- ensure that the incentive for AGN to make efficiency gains is the same irrespective of the year in which an investment is made.

AGN therefore considers that a CESS is an important part of the overall package of incentives applied to the business to improve its productivity performance.

As part of the recent review of (and subsequent changes to) the National Electricity Rules (NER), the Australian Energy Market Commission (AEMC) identified that a key issue with capex incentives in the absence of a CESS was that *"… the power of the incentive to incur capital expenditure efficiently declines during a regulatory control period."*[108]

The AER noted in its Explanatory Statement for the CESS that this declining incentive may deliver an incentive for businesses to spend more towards the end of a regulatory control period, which in turn: *"may lead to inefficient capex and inefficient substitution of opex for capex towards the end of a regulatory control period".*[109]

These issues have the potential to arise in South Australia given there is currently an EBSS but not a similar (or offsetting) CESS.

In order to address the above, the AEMC amended the NER to give the AER the discretion to apply a capex incentive mechanism. In doing so the AEMC identified that there were numerous benefits from capex sharing schemes:

> *"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."* [110]

In response, the AER developed the CESS, which has the following key attributes:

- the scheme provides for the same reward and penalty, which is determined as the difference between actual and benchmark capex for the entire five-year regulatory period;
  - the calculated CESS amount is added as a building block in the determination of Total Revenue for the next AA period (in the same way the EBSS is now a building block in determining our Total Revenue for the next AA period);
- 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;
  - AGN notes, however, that it is currently unclear what the AER will define as 'material' as no business is yet to complete a full five year period with the CESS in operation (AGN has proposed adjustments to remove this uncertainty).

The CESS that has been designed by the AER is calculated as follows:

1. determine the NPV of the under/over spend during the current AA period;

---

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

[109] AER 2013, "*Better Regulation Explanatory Statement Capital Expenditure Incentive Guideline*", November 2013, pg. 7.

[110] AEMC 2012, "*Economic Regulation of Network Service Providers, and Price and Revenue Regulation of Gas Services, Final Position Paper*", November 2012, pg. 97.

2. multiply this amount by 30%, which reflects the share to be retained by the business;
3. reduce the amount determined from the above two steps by the NPV of the financing benefit/loss already received by the business over the current AA period; and
4. recover the determined CESS amount through an increase/decrease in revenue in the next AA period.

As indicated earlier, we intend to make certain modifications to the operation of the CESS to strengthen the incentive and to provide greater certainty over the adjustments that can be made to the capex benchmarks in administering the scheme. In particular, AGN is proposing to:

- set the percentage amount in Step 2 above to 50%, such that there is an equal sharing of the efficiency gains and losses between the business and consumers; and
- limit the scope for windfall gains or losses to arise (see following section).

12.5.2.1 Proposed Limited Scope for Windfall Gains or Losses

AGN intends to provide greater certainty over the adjustments that can be made to the CESS. Our intention is to limit the potential for windfall gains or losses to arise by allowing for adjustments to be made to account for differences in the actual and benchmark scope of services delivered by the business over the next AA period. This will ensure that the scope for rewards or penalties responds only to actions taken by management.

The value of the adjustment to the benchmarks is proposed to be determined by multiplying the difference between actual and benchmark:

- volumes of mains replacement undertaken over the next AA period;
- domestic and non-domestic customer connections by the benchmark unit rate for those connections; and
- domestic and non-domestic meter replacements by the approved unit rate for those replacements.

Not adjusting the benchmark unit rates maintains the incentive to outperform the cost of providing the above outputs to consumers.

AGN considers that it should maintain some incentive to also outperform on the scope of work that underpins the benchmarks, which outperformance is in the long term interests of consumers. AGN has therefore proposed to apply a 10% ‘dead band’ around the benchmark volume assumption. This provides an incentive to outperform volumes by allowing AGN to retain any such outperformance up to a maximum of 10% (and vice versa if above benchmark volumes are incurred).

AGN considers that the above adjustments will address much of the concern about the incentive for capex to be deferred between AA periods under a CESS, while still providing some incentive to the business to outperform the benchmark volume assumption. Consistent with the EBSS, specifying the nature of the adjustments beforehand will provide greater certainty to the business, and stakeholders more generally, over how the CESS will be applied over the next AA period.

12.5.3 Customer Service Incentive Scheme

AGN considers, consistent with our stakeholder feedback, that the incentive arrangements to apply over the next AA period should also include appropriate incentives to improve customer service. For example, around 60% of those participants that attended our stakeholder workshops indicated that they are willing to pay for the introduction of a Guaranteed Service Level (GSL) scheme in South Australia, which provides compensation to those customers that receive service below an ‘agreed’ level (see Chapter 3 for more information on our stakeholder engagement program).

There are, however, practical constraints to introducing effective customer service incentives at the start of the next AA period. This was noted in our submission to the Essential Services Commission of South Australia (ESCOSA), who is responsible for setting the service standards that AGN is required to meet over the next AA period. AGN noted in its submission to ESCOSA that:

> *"… it is apparent to AGN that stakeholders are supportive of the principle of having a formal scheme in place to compensate those customers impacted by service that is below an agreed standard and/or to incentivise the business to provide improved performance overtime. There are however some practical considerations that are limiting our ability to introduce a GSL scheme at this point in time (such as data availability).*
>
> *… We will also continue to work with stakeholders to consider how the principle of formal compensation can be best implemented in the medium-term, having regard to the additional data that will become available with the introduction of our new operating systems".*[111]

Our intention therefore is to continue to engage with stakeholders, including the AER, to ensure any incentives to improve customer service best reflect customer values and provide a meaningful incentive on the business to improve performance. An example of what the scheme parameters may look like, are as follows:

- customer service incentive strength of ±1% of revenue (similar to similar schemes that apply elsewhere);
- areas of customer service targeted by the scheme:
  - telephone responsiveness – leaks and emergency line;
  - telephone responsiveness – general enquiry line; and
  - number of complaints.

AGN intends to undertake this consultation in 2016 with a view to introducing a customer service incentive scheme on 1 July 2017.

AGN notes that our Vision Statement, which is set out in Chapter 2 of this AAI, requires the setting and reporting of our performance across several key aspects of customer service. This includes the time taken to respond to publicly reported gas leaks, our call centre responsiveness and the number of complaints received from the public. AGN believes the targets set out in its vision would provide a good base for the development of the customer service incentive scheme.

12.5.4 Network Innovation Scheme

The incentive for a regulated business to invest in innovation is materially different to an unregulated business. For example, an unregulated business has the incentive to invest in innovation on the basis that it creates the possibility of materially increasing its customer base and/or increasing profit levels for a period of time.

The key difference for a regulated business relates to the resetting of costs (and prices) 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 regulated benchmarks;

[111] AGN 2015, "*Further Submission on Jurisdictional Service Standards for the 2016 to 2021 Access Arrangement Period*", 16 January 2015, pg.6. Provided at Attachment 3.10 to this AAI.

- revenue/prices are reset shortly after the innovation (such that the benefits of that innovation are also passed through to consumers 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 demonstrates that the scope/incentive for a regulated business to invest in innovation is limited by economic regulation. This limits the flow of profits for the business to an (unlikely) maximum of five years at the regulated cost of capital. There is the (likely) potential, however, that the costs and risks associated with the innovation spending may require a longer payback period, particularly in light of the 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 clearly not in the long-term interests of consumers, and as such, does not lead to outcomes that promote the NGO. The objective of the proposed Network Innovation Scheme (NIS) is to overcome the disincentive for innovation that is created through the standard application of incentive-based regulation.

AGN considers that the need to encourage innovation is particularly important given the energy sector is undergoing significant change, including as a result of the emergence of new technologies. Customers are increasingly looking to take more control of their energy consumption decisions, including how that energy is supplied.

Given gas is a fuel of choice, there is a significant risk that a lack of innovation now, either to reduce costs and/or to improve services, will increase the number of customers that choose to disconnect from the Network. This in turn introduces the risks of underutilised assets and the commonly referred to 'negative spiral' (where declining volumes lead to higher prices, thereby leading to further declines in volume and so on).

AGN has consulted with other gas pipeline businesses in the UK that are exposed to an innovation allowance. For illustrative purposes, these businesses have identified the following two current examples of projects that are being considered for innovation funding:

- research into the long-term role of gas and gas networks – including looking into the gas quality/composition of different sources of gas and factors that impact the storage capabilities of gas networks; and
- innovations to avoid future cost increases and deliver value for money outputs – including research into new products that more effectively identify pipe fractures / weak points and alternative leakage management techniques from other sectors (e.g. water).

AGN notes that results from its stakeholder engagement program demonstrate that consumers are willing to pay for initiatives that are aimed at lowering future prices. Deloitte, which was engaged by AGN to report on the insights generated from our stakeholder engagement program, noted that:

- customers value initiatives that improve community safety across the network; and
- customers support expanding and improving the network where there is a clear benefit to residents and business.

Network innovation is consistent with the above stakeholder insights. The Deloitte Stakeholder Insights report is provided as Attachment 3.9 to this AAI.

12.5.4.1 Precedent for Innovation Funding

There is considerable national and international precedent for the use of incentives to facilitate the development of innovative networks solutions.

In Australia, the NER provide that electricity distributors may develop and publish an incentive scheme that provides incentives to implement non-network alternatives to meet demand, or to manage the expected demand for network services in some other way or to efficiently connect embedded generators to the network.[112] AGN notes that incentives under this scheme have generally been in the form of an additional funding allowance.

Ofgem in the UK has placed a considerable focus on the role of innovation through the RIIO (Revenue = Incentives + Innovation + Outputs) regulatory framework. In developing the RIIO framework, Ofgem identified the following reasons that explain why energy network businesses may be reluctant to investigate innovations:

> *"2.4. In terms of the quantum of innovation, network companies may also be slow to deliver the amount required, or deliver within the required timescales, for a variety of reasons including:*
>
> - *the company may not take account of all the benefits from innovation that accrue to a wide range of parties as they consider the relative merits of innovations;*
> - *the upfront costs of innovation may be significant;*
> - *the long-term private cost to network companies from choosing not to innovate may not be significant because the costs associated with continuing to deploy existing technologies are generally funded under a price control; and*
> - *network companies may discount the future benefits of innovation to facilitate a low carbon energy sector if the carbon price is low or they doubt the political commitment to meet the targets."*[113]

The RIIO framework includes an innovation stimulus package to fund innovation where the commercial benefits may be uncertain, and as such, gas and electricity distributors are not willing to fund research and development projects speculatively. The innovation stimulus consists of the following:

- *Network Innovation Allowance (NIA)* – allows for the (ex-post) recovery of costs to fund small-scale innovative projects (up to 0.5% of annual revenue on a 'use-it-or-lose-it' basis);

- *Network Innovation Competition (NIC)* – an annual competition for funding larger, more complex projects that have the potential to deliver low carbon and/or wider environmental benefits to consumers (revenue is awarded based on competitive bidding);

- *Innovation Roll-out Mechanism (IRM)* – allows for the pass-through of the costs for the rollout of initiatives that have demonstrable and cost effective low-carbon and/or environmental benefits.

We note also that financial support for research and development has been a continued focus for Australian Governments. This funding support recognises that innovation can deliver substantial benefits to the economy but is challenging for businesses to pursue. Some examples of government support for research and development include:

- The Research and Development Tax Incentive aims to help businesses offset some of the costs associated with innovation;[114]

---

112 National Electricity Rules, Clause 6.6.3(a).

113 Ofgem 2010, "*Regulating Energy Networks for the Future: RPI-X@20 Emerging Thinking – A Specific Innovation Stimulus*", January 2010, pg. 2.

114 See: http://www.business.gov.au/grants-and-assistance/innovation-rd/RD-TaxIncentive/Pages/default.aspx

- The Australian Renewable Energy Agencies Research and Development Program supports renewable energy technologies that will increase the commercial deployment of renewable technologies in Australia, up to $300 million over the period 2013 to 2022 has been allocated to develop this research and development portfolio;[115] and

- Cooperative Research Centres (CRC) have been a feature of government support for innovation since 1990 – the CRC program supports industry-led collaborations between researches, industry and the community.[116]

12.5.4.2 Design Features of the Network Innovation Scheme

AGN proposes that the Network Innovation Scheme (NIS) be structured in a similar way to the NIA that applies in the UK. More specifically, AGN proposes that the NIS include the following features:

- AGN can recover, after-the-fact, up to $1 million per year of expenditure incurred that relates to innovation through the annual Reference Tariff Variation Mechanism (see Chapter 15). That is, there is no innovation allowance included in the expenditure benchmarks, but expenditure can be recovered once it is incurred by the business. AGN notes that the $1 million threshold is equivalent to around 0.5% of total annual revenue (as per the NIA in the UK);

- AGN is to seek the prior approval of the AER for any expenditure on innovation that is forecast to exceed the $1 million threshold;

- AGN is to have any expenditure on innovation that it seeks to recover subject to independent review to verify the expenditure incurred (similar to the process of independent review of our actual volumes as part of the annual Reference Tariff Variation Mechanism);

- any approved expenditure on innovation is excluded from the operation of the EBSS and CESS; and

- the AER is to approve the actual recovery of innovation funding through the annual Reference Tariff Variation Mechanism.

In order to receive the funding, it is proposed that AGN is required to demonstrate that the use of the innovation funding meets the following criteria (which criteria are similar to that used by Ofgem to administer the NIA):

- the project must have the potential to have a direct impact on AGN's operations and involve the research, development, or demonstration of at least one of the following:
  - a piece of new equipment, such as control and communications systems and software;
  - a novel arrangement or application of existing network infrastructure;
  - a novel operational practice directly related to the operation or safety of the network or improvement in customer service; or
  - a novel commercial arrangement;

- the project must have the potential to develop learning that can be applied by other gas pipeline distributors in Australia;

- the project must have the potential to deliver net financial benefits and/or improvements in customers service to gas customers; and

---

115 See: http://arena.gov.au/initiatives-and-programs/research-and-development-program/

116 See: http://www.business.gov.au/grants-and-assistance/Collaboration/CRC/Pages/default.aspx

- any intellectual property developed must be made available to third parties.

AGN notes that this assessment of projects against the criteria is not intended to be an assessment of the broader merits, or efficiency of the expenditure after it has been incurred. This is because, after-the-fact, it is possible that expenditure on unsuccessful innovations might not otherwise be considered prudent. The criteria is instead intended to govern the independent review of any innovation expenditure that is incurred by the business and to guide AER decision making on expenditure over the $1 million threshold.

12.6 Assessment Against the National Gas Objective and Revenue and Pricing Principles

The NGO is 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 of natural gas.

The Revenue and Pricing principles provide that:

> *"A service provider should be provided with effective incentives in order to promote economic efficiency with respect to reference services the service provider provides. The economic efficiency that should be promoted includes -*
>
> *(a) efficient investment in, or in connection with, a pipeline with which the service provider provides reference services; and*
>
> *(b) the efficient provision of pipeline services; and*
>
> *(c) the efficient use of the pipeline."*[117]

In considering whether under Rule 98 of the NGR an incentive mechanism should be put in place and the form it should take, the AER (and AGN) is required by the National Gas Law to seek to achieve the NGO and take into account the Revenue and Pricing Principles.

Given this, incentive mechanisms should be employed in circumstances where they will (i) advance the NGO and (ii) advance (or do not operate inconsistently with) the Revenue and Pricing Principles. AGN therefore considers that, in considering the proposed changes to the incentive arrangements, the AER should have regard to:

- whether the proposed incentives will encourage the achievement of further cost efficiencies; and
- whether the incentives are likely to promote the achievement of improved services.

In this context the approach and experience of other regulators is relevant. If other regulators have assessed that certain forms of incentive mechanism are most appropriate to drive efficiencies then this should be taken into account by the AER in determining the appropriate form of incentive mechanism. Indeed, the AER has applied the CESS to electricity distribution in Australia on the basis that this will better promote the National Electricity Objective.[118]

Equally, if the experience of network service providers generally in Australia suggests a reduction in the rate of achievement of further efficiencies then this suggests that the current mechanisms are not operating in an optimal fashion.

AGN considers that the Revenue and Pricing Principles and the NGO will be best achieved through the incentive arrangements that are proposed by AGN to apply over the next AA period. This is because the incentive arrangements are designed to strengthen the incentive for AGN to reduce its costs (and hence

[117] National Gas Law, Section 24(3).

[118] The National Electricity Objective is expressed in the same terms as the NGO.

prices) and/or improve the services provided to customers. The proposed incentive arrangements complement our Vision Statement to deliver for customers, employees and stakeholders.

AGN considers the best way to promote continued economic efficiency is to enact the amendments proposed, namely:

- *EBSS* – increase the share of benefits and losses from 30% to 50%; this will strengthen the incentives to AGN to seek further (and more costly) efficiencies (including to take risks in seeking efficiencies it might not otherwise have taken under the current sharing ratio);
- *CESS* – introduction of the capex incentive mechanism also with a sharing ratio of 50%; this will have the effect of strengthening the incentive to achieve capital efficiencies and avoid the potential for distortions in expenditure patterns created by having an efficiency scheme apply to only opex and not capex;
- *Customer Service Incentive* – consult with stakeholders with a view to introducing a customer service incentive scheme on 1 July 2017; this will provide a meaningful incentive on the business to improve customer service performance; and
- *Innovation* – introduction of a Network Innovation Scheme; this will encourage long-term research and development into means for improving the provision and cost efficiency of services, which long-term research and development might not otherwise occur.

Each of the four amendments are consistent with the inherent expectation of the Revenue and Pricing Principles as the amendments:

- strengthen the incentive for the identification and implementation of network efficiencies;
- align the incentive rate between capex and opex to strengthen the incentive to ensure that the most appropriate form of expenditure is used; and
- remove the barriers to innovation so that:
  - more cost effective investments can be identified and made that ultimately deliver price benefits to customers, and
  - innovative solutions to improving the safety, reliability and security of supply can be tested and implemented where benefits are identified.

The benchmarking work undertaken by Economic Insights has demonstrated the flattening of productivity gains in recent history across Australian gas distribution businesses. AGN considers its proposed amendments to the incentive arrangements will increase the scope for businesses to make more costly efficiency investments, driving greater cost reductions while at least maintaining, if not improving, the quality, safety, reliability and security of supply for customers, and therefore promote the NGO.

12.7 Summary

AGN is proposing that a more comprehensive set of incentive arrangements apply over the next AA period, including:

- the retention of an EBSS for opex;
- the introduction of a CESS for capex;
- the introduction of a NIA; and
- the introduction of a customer service incentive scheme to apply from 1 July 2017.

With respect to the expenditure incentives, AGN considers that symmetrical and continuous incentives for both capex and opex will better promote prudent and efficient expenditure decisions. In particular, the operation of both schemes in combination will ensure that the most efficient network solution is always taken because there is no bias towards one form of expenditure over another.

AGN has also proposed that the power of the incentives provided for under the EBSS and CESS be strengthened. This reflects that AGN has been subject to incentive regulation for some time, and similar to other businesses, ongoing efficiency improvements are more difficult (and costly) to achieve. This approach not only better reflects the circumstances for AGN but is also consistent with the evolution of similar incentive schemes that apply to gas pipeline businesses in the UK.

Another key feature of our proposed incentive arrangements relates to the introduction of an innovation allowance, which is intended to overcome the barriers to innovation expenditure that arise as a consequence of the resetting of costs (and prices) on a periodic basis. Similar innovation allowances apply for electricity network businesses in Australia and also gas and electricity network businesses in the UK.

Consistent with our stakeholder feedback, we also consider that appropriate incentives to improve customer service should be applied over the next AA period. As noted, there are practical constraints to introducing effective customer service incentives at the beginning of the next AA period, including the availability of data to inform such a scheme. Our intention therefore is to continue to engage with stakeholders, including the AER, to design and implement an incentive scheme to improve customer service during the next AA period.

Page intentionally left blank

13 Total Revenue

Page intentionally left blank

13 Total Revenue

13.1 Introduction

The preceding chapters of this Access Arrangement Information (AAI) have defined for the next (2016/17 to 2020/21) Access Arrangement (AA) period:

- the Haulage Reference Services (HRS) and Ancillary Reference Services (ARS) that Australian Gas Networks Limited (AGN) will provide to its South Australian customers (see Chapter 6); and
- the cost of providing HRS and ARS (see Chapters 7, 8, 9, 10, 11, 12).

The forecast costs of providing HRS and ARS are referred to as the 'building blocks' that are summed to determine the notional (or unsmoothed) total revenue (referred to as building block total revenue) in each year of the next AA period. The forecast revenue from providing ARS (referred to as ARS building block revenue) is then subtracted from the building block total revenue to determine the revenue from providing HRS (referred to as HRS building block revenue).

A price path is then set to profile (or smooth) the recovery of HRS building block revenue over the next AA period (referred to as HRS reference tariff revenue).

This chapter sets out the building block total revenue, the ARS building block revenue, HRS building block revenue and HRS reference tariff revenue for each year of the next AA period.

13.2 Requirements of the National Gas Rules

Rule 76 of the National Gas Rules (NGR) requires that total revenue for each year of the next AA period is to be determined using the building block approach, in which the 'building blocks' are:

- a forecast of operating expenditure for the year (see Chapter 7);
- a return on the projected capital base for the year (see Chapters 8, 9 and 10);
- depreciation of the projected capital base for the year (see Chapter 9);
- a forecast of the cost of tax (see Chapter 11); and
- any increments or decrements for the year resulting from the operation of an incentive mechanism to encourage gains in efficiency (see Chapter 12).

Rule 92(2) requires that the present value of the HRS building block revenue equals the present value of the HRS reference tariff revenue over the next AA period.

The NGR also allows AGN to provide a *"prudent discount"* to the reference tariff that would otherwise apply to retain and/or attract a customer to take supply from the South Australian natural gas distribution network (the Network). Specifically, Rule 96 states:

> *"(1) Despite the other provisions of this Division, the AER [Australian Energy Regulator] may, on application by a service provider, approve a discount for a particular user or prospective user or a particular class of users or prospective users.*
>
> *(2) The AER may only approve a discount under this rule if satisfied that:*
>
> *(a) The discount is necessary to:*
>
> *(i) Respond to competition from other providers of pipeline services or other sources of energy; or*

> (ii) *Maintain efficient use of the pipeline; and*
>
> (b) *The provision of the discount is likely to lead to reference or equivalent tariffs lower than they would otherwise have been.*
>
> (3) *If the AER approves a discount under this rule, the AER may also approve allocation of the cost, or part of the cost, of providing the discount to the costs of providing a reference or other service in one or more future access arrangement periods.*
>
> (4) *In this rule:*
> ***equivalent tariff*** *means the tariff that is likely to have been set for a service that is not a reference service if the service had been a reference service."*

13.3 Ancillary Reference Service Revenue

As explained in Chapter 6, ARS are those Reference Services that are specifically requested to be provided by a Network User (Chapter 6 also lists the ARS). The forecast volume of ARS to be provided over the next AA period is explained in Chapter 14 while the derivation of the ARS tariffs is explained in Chapter 15. Table 13.1 sets out the ARS building block revenue, which is determined by multiplying forecast volume by the prevailing tariffs for an ARS in each year.

TABLE 13.1: FORECAST REVENUE FROM ANCILLARY REFERENCE SERVICES, 2016/17 TO 2020/21

$ million (nominal)	2016/17	2017/18	2018/19	2019/20	2020/21
Disconnection	0.46	0.48	0.50	0.52	0.54
Reconnection	0.35	0.36	0.38	0.39	0.41
Special Meter Reads	1.29	1.34	1.39	1.44	1.50
Meter Removal	0.10	0.11	0.11	0.11	0.11
Meter Reinstallation	0.01	0.01	0.01	0.01	0.01
Meter Gas and Installation Test	0.03	0.03	0.03	0.03	0.03
Total	**2.24**	**2.32**	**2.41**	**2.50**	**2.59**

Note: Totals may not add due to rounding.

13.4 Prudent Discounts

Some of our larger industrial customers have a feasible option of either:

- bypassing the Network to take supply directly from the natural gas transmission pipeline; or
- using electricity rather than gas (noting that, in most cases, natural gas is a fuel of choice).

Under these scenarios, AGN may be required to offer a discount to the Reference Tariff to attract or retain the customer on the Network. AGN is required to determine whether attracting a new or retaining an existing large industrial customer by negotiating a discount to the Reference Tariff (referred to as a prudent discount) is in the best interests of existing customers. This occurs when the incremental revenue received from the customer is higher than the incremental costs of providing HRS to that customer.

The existing customer base is better off under this scenario because the difference between incremental revenue and cost is reflected through lower Reference Tariffs to existing customers than would otherwise be the case. This reflects that any revenue recovered in excess of the incremental cost from serving that customer contributes to the fixed costs of providing HRS (which fixed costs do not change regardless of whether the new customer connects to the Network or not).

The information regarding prudent discounts is confidential as it relates to the particular circumstances of an individual customer (this information is provided in Attachment 13.1 (Prudent Discount Summary). This attachments are provided on a confidential basis to the Australian Energy Regulator (AER) to verify that the incremental (discounted) revenue exceeds the incremental cost for each customer that receives a prudent discount.

Given the above, the provision of the prudent discount has lowered Reference Tariffs to existing customers taking supply from the Network. The proposed prudent discounts are therefore consistent with Rule 96(2)(b).

13.5 Building Block Revenue

This AAI has set out the derivation of all the relevant building blocks that are used to determine the building block total revenue, aside from the return on capital building block. This is determined by multiplying the rate of return (or weighted average cost of capital) of 7.23% (Chapter 10) by the opening regulatory asset base (RAB) in each year of the next AA period (Chapter 9). The building block total revenue, ARS building block revenue and HRS building block revenue is set out in Table 13.2.

TABLE 13.2: BUILDING BLOCK TOTAL REVENUE, 2016/17 TO 2020/21

$ million (nominal)	2016/17	2017/18	2018/19	2019/20	2020/21
Return on Capital	103.3	113.0	123.7	133.7	143.8
Return of Capital	11.4	14.9	20.1	23.4	23.2
Operating Expenditure	71.6	75.8	79.8	82.2	85.2
Incentive Mechanism	7.4	-1.5	-1.7	1.8	0.0
Cost of Tax	9.5	6.6	7.5	8.3	6.3
Building Block Total Revenue (including ARS)	**203.2**	**208.7**	**229.4**	**249.4**	**258.4**
ARS Building Block Revenue	2.2	2.3	2.4	2.5	2.6
HRS Building Block Revenue (excluding ARS)	**200.9**	**206.4**	**227.0**	**246.9**	**255.8**

Note: Totals may not add due to rounding.

AGN has then determined a price path to ’smooth’ the HRS building block revenue. This is achieved by setting the present value of the HRS building block revenue equal to the present value of the forecast revenue to be recovered from Reference Tariffs (HRS reference tariff revenue), inclusive of the prudent discounts. This ’smoothing‘ of revenue gives rise to a series of percentage changes (or X factors) setting out how Reference Tariffs in each year need to change for the above equilibrium to be achieved.

The HRS building block revenue, HRS reference tariff revenue and price path are provided in Table 13.3. AGN has developed its proposed price path in order to:

- provide for revenue growth that, to the extent possible, matches the growth in the regulatory asset base (RAB) over the next AA period, which we consider is consistent with achieving/maintaining stable credit metrics consistent with the benchmark credit rating set by the AER (i.e. BBB+/Baa1); and

- to equate revenue with our underlying costs in 2020/21 (the last year of the next AA period) to ensure that there is no one-off adjustment to tariffs (either positive or negative) required from 1 July 2021 to equate tariff revenue with costs.

This approach leads to a larger price (i.e. tariff) cut on 1 July 2016 than would otherwise occur, followed by price growth (i.e. in line with the growth in our RAB). More specifically, AGN is proposing to reduce tariffs by 11% in real (excluding inflation) terms on 1 July 2016, followed by tariff increases of 5% in real terms in each remaining year of the next AA period.

The 5% real price growth rate matches the growth in our RAB and therefore in our debt (at a constant debt-to-RAB ratio). This provides for stable credit metrics, such as the funds from operation (FFO) to debt ratio, which is important to maintaining a stable credit rating and therefore an efficient cost of capital. AGN engaged Incenta Economic Consulting to review our proposed price path against an alternate price path of have a one-off price adjustment and no real change in prices thereafter (Attachment 5.1).Incenta found:

> *"I find that AGN's proposed price path generates credit metrics that are much smoother over the period than the alternative path that was assessed, and also that AGN's proposal is expected to generate less of a price change between the next Access Arrangement period and the subsequent period (a price reduction of 2.3 per cent compared to a price increase of 8.0 per cent). I therefore conclude that, out of the alternatives, AGN's proposed price path is superior both in terms of meeting the financeability objective and the price path objective."*[119]

The price path objective referred to in the above is concerned with minimising the difference between revenue and underlying costs while the financeability objective is concerned with ensuring the decision allows AGN to maintain the AER benchmark credit rating at BBB+/Baa1.

TABLE 13.3: PROPOSED PRICE PATH, 2016/17 TO 2020/21

	2016/17	2017/18	2018/19	2019/20	2020/21
HRS Building Block Revenue ($ million nominal)	200.9	206.4	227.0	246.9	255.8
HRS Reference Tariff Revenue (including Prudent Discounts) ($ million nominal)	201.6	212.7	225.9	240.1	255.7
Real Price Path	11.4%	-5.0%	-5.0%	-5.0%	-5.0%

Note: The price path has been calculated as Tariff 2015/16 x (1+[Consumer Price Index]I) x (1-X). This price path equates the present value of the HRS building block revenue with the HRS Reference Tariff Revenue using the regulatory rate of return of 7.23%.

Table 13.4 details the expected revenue to be recovered from each tariff class (see Chapter 15 for further information on tariff classes). The total revenue recovered from all Reference Tariffs reconciles with the HRS reference tariff revenue detailed in Table 13.3 above.

TABLE 13.4: RECONCILIATION OF REVENUE RECOVERY BY TARIFF CLASS TO HAULAGE REVENUE REQUIREMENT

Tariff Revenue ($ million nominal)	2016/17	2017/18	2018/19	2019/20	2020/21
Tariff R	155.8	164.9	175.0	185.8	197.7
Tariff C	27.9	29.8	31.8	34.0	36.4
Tariff D (including Prudent Discounts)	17.9	18.0	19.1	20.3	21.6
Total (HRS Reference Tariff Revenue)	**201.6**	**212.7**	**225.9**	**240.1**	**255.7**

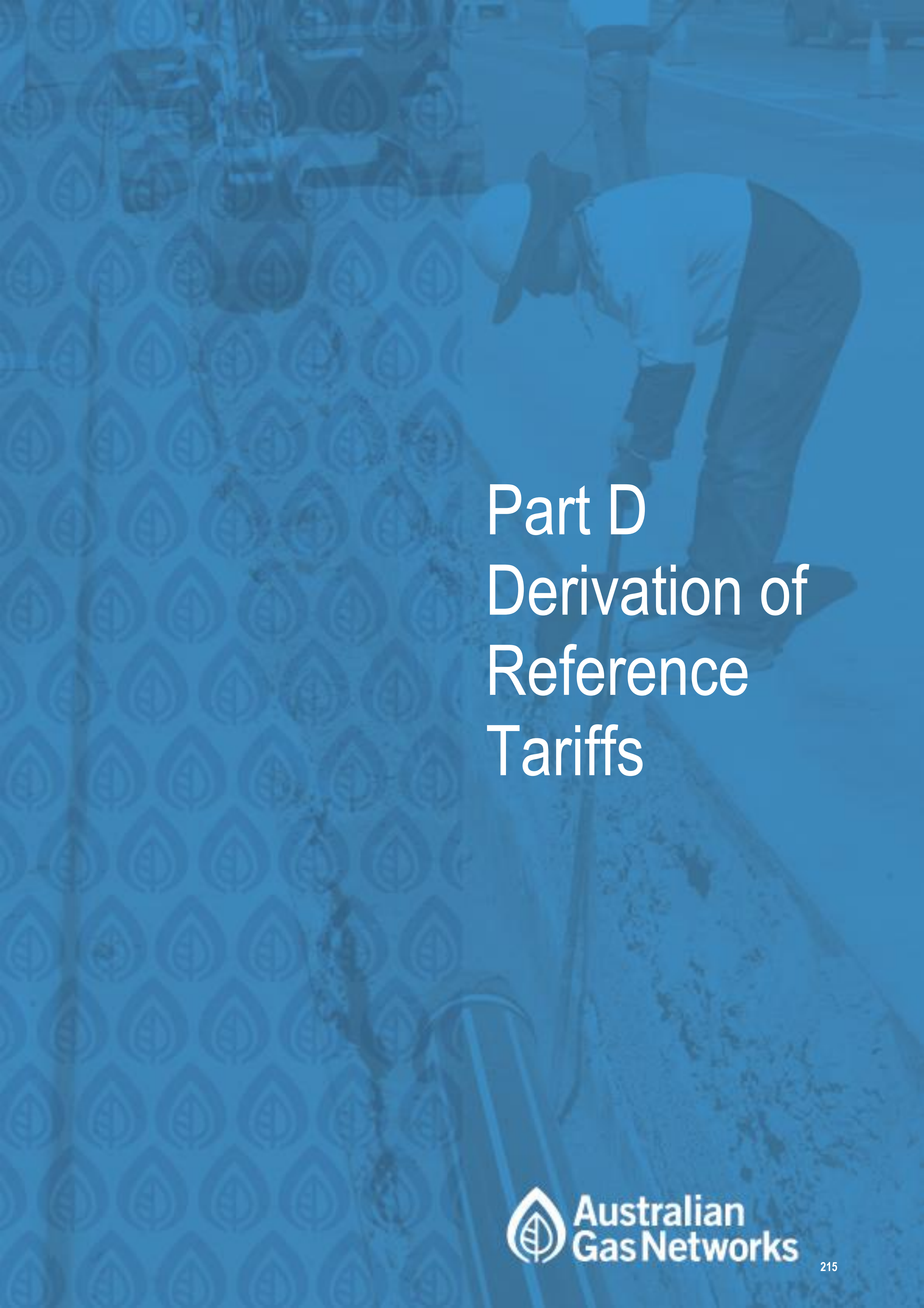
Note: Totals may not add due to rounding.

Finally, Table 13.5 details the expected revenue to be recovered from tariffs, smoothed and including ARS in both real and nominal terms

TABLE 13.5: SMOOTH TARIFF REVENUE RECOVERY INCLUDING ARS (REAL AND NOMINAL)

$million	2016/17	2017/18	2018/19	2019/20	2020/21
$2014/15	196.2	202.0	209.2	216.9	225.3
Nominal	203.8	215.0	228.3	242.6	258.3

[119] Incenta Economic Consulting 2015, "*Using the Profile of Prices During an Access Arrangement Period and Return on Capital to Improve Financial metrics*", 17 June 2015, pg. 3.



Part D Derivation of Reference Tariffs

Page intentionally left blank

14 Demand Forecasts

Page intentionally left blank

14 Demand Forecasts

14.1 Introduction

This chapter of the Access Arrangement Information (AAI) outlines forecasts of gas consumption and customer numbers (collectively referred to as AGN's demand forecasts) for each customer class over the next (2016/17 to 2020/21) Access Arrangement (AA) period. These forecasts are a key input into determining:

- *Capital Expenditure* – the growth capital expenditure (capex) forecast is determined as the forecast growth in connection numbers by customer class multiplied by the relevant unit rate (see Chapter 8);
- *Operating Expenditure* – operating expenditure (opex) forecasts are in part driven by the forecast growth in connection numbers multiplied by the cost per connection (see Chapter 7); and
- *Reference Tariffs* – under a price cap form of regulation, prices are determined by dividing total revenue (Chapter 13) by the demand forecasts (see Chapter 15).

The South Australian natural gas distribution network (the Network) has faced challenging conditions over recent years. These challenges include warming weather patterns, concerns over increasing retail gas prices, ongoing subdued economic conditions and increased penetration of competing energy sources and appliances. This has resulted in a trend decline in the average annual consumption of natural gas for consumers connected to the Network.

As described in this chapter, Australian Gas Networks Limited (AGN) has only achieved (exceeded) the benchmark residential demand forecasts in South Australia, as set by the regulator, once since regulatory determinations began 16 years ago. This underperformance carries a high degree of risk for the business, given that the residential sector accounts for around 75% of our total revenue recovery. A similar situation has also arisen in respect of the benchmark demand forecasts for our business and industrial customer segments.

AGN has engaged Core Energy Group (Core Energy) to develop forecasts of gas consumption and customer numbers over the period from 2014/15 to 2020/21 (total forecast period), which encompasses the next AA period. Core Energy's forecasting approach is based on the principles applied by the Australian Energy Market Operator (AEMO)[120] in forecasting gas demand in South Australia. Core Energy has also sought to be consistent with past approaches submitted to the Australian Energy Regulator (AER).

In summary, Core Energy expects recent trends to continue over the forecast period, that is:

- slowing growth in customer connections; and
- continued trend decline in average consumption per connection.

The demand forecasts for the next AA period are discussed in this chapter.

14.2 Requirements of the National Gas Rules

Rule 74 of the National Gas Rules (NGR) is the relevant rule applicable to preparing demand forecasts. Rule 74 requires:

> *"(1) Information in the nature of a forecast or estimate must be supported by a statement of the basis of the forecast or estimate.*

[120] ACIL Allen 2014, "*Report to Australian Energy Market Operator: Gas Consumption Forecasting - A Methodology*", June 2014.

(2) A forecast or estimate:

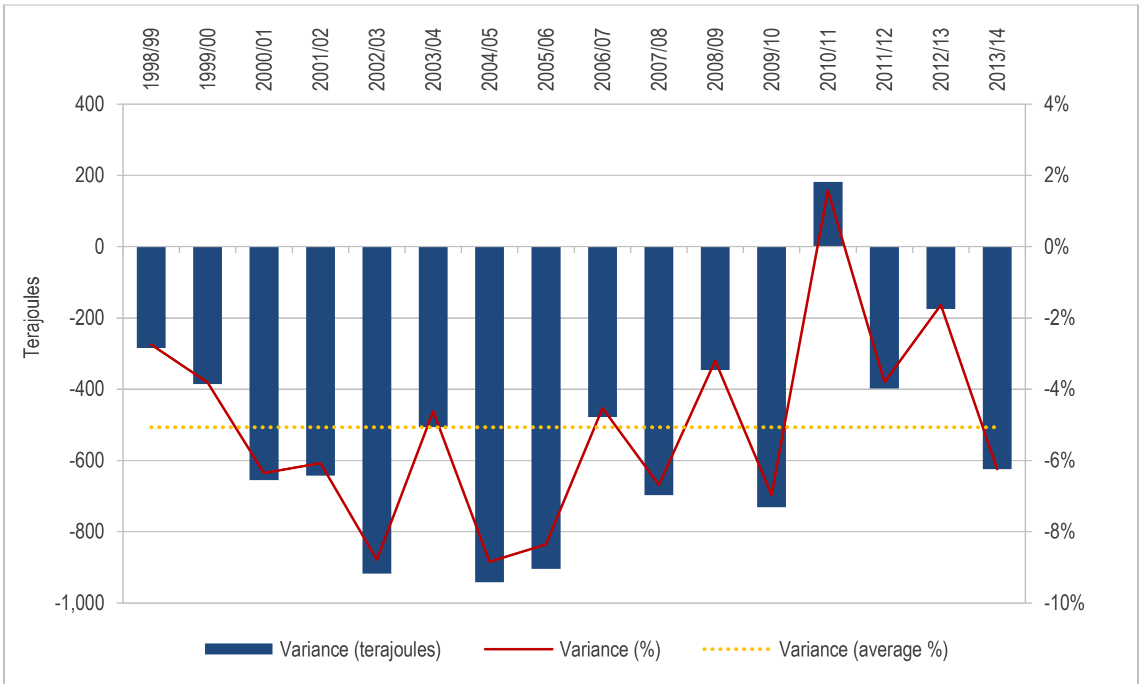
(a) must be arrived at on a reasonable basis; and

(b) must represent the best forecast or estimate possible in the circumstances."

14.3 Past Performance

Since regulatory determinations began in 1998/99, AGN has only achieved (exceeded) demand benchmarks set by the regulator (referred to as 'benchmarks' hereafter) for our volume customers (residential and commercial/small industrial customers who consume less than 10 terajoules per annum) once (see Figure 14.1). Furthermore, on average over the 16-year period from 1998/99 to 2013/14, actual volumes have been around 5.1% below the benchmarks set by the regulator. In the current (2011/12 to 2015/16) AA period, AGN estimates that our inability to achieve the volume benchmarks has led to a $57 million under recovery in actual revenue (see Chapter 4).

FIGURE 14.1: BENCHMARK AND ACTUAL RESIDENTIAL AND COMMERCIAL VOLUME VARIANCE, 1998/99 TO 2013/14



Note: Variance is calculated as actual less allowed (benchmark) consumption.

The primary reason for the variance is that actual consumption per connection is declining at a faster rate than forecast in the benchmarks set by the regulator. This reflects a number of drivers, including warming weather trends, continuous improvements in energy efficiency (appliance efficiency and building thermal efficiency), customer appliance preferences (electric reverse-cycle air-conditioning instead of gas space heating), customer response to increasing energy prices and the significant installation of solar equipment in recent years.

These challenges are expected to continue over the next AA period, particularly given:

- further substantial increases in renewable generation – a high penetration of 'green' electricity reduces the environmental driver for customers to use natural gas;
- the emergence of new technologies – including continual technological improvements in distributed generation, battery storage and electric vehicles (which will reduce the unit price of electricity by resulting in a step change in volumes and/or make consumers more electricity focused in their appliance choice/use);

- further increases in the penetration rates of reverse-cycle air-conditioners – which reduces the up-front cost of switching from gas to electricity; and

- a move to cost reflective electricity network prices – in areas with a peak summer load, such as South Australia, electricity tariffs would increase during peak times in summer and decrease in off-peak times in winter (i.e. during periods of peak (winter) gas demand).

Further detail on the past performance of each customer class is provided later in this chapter.

14.4 Forecasting Approach

Table 14.1 sets out the nature of the forecasts that Core Energy was asked to prepare. These forecasts reflect the manner by which each customer group is billed. For example, forecasts of Maximum Daily Quantity (MDQ) are not required for residential customers as this group is charged based on the volume of gas used. This information therefore reflects that required to forecast regulatory revenue from Reference Tariffs over the next AA period (see Chapter 13).

TABLE 14.1: FORECASTS PREPARED BY CORE ENERGY

Customer Class	Description	Forecast Prepared by Core Energy		
		Customer Numbers	Volume	MDQ
Tariff R – Residential	These are residential customers who consume less than 10 terajoules per annum.	✓ Yes	✓ Yes	Not required
Tariff C – Commercial	These are network users who consume less than 10 terajoules per annum and are commercial or small business customers.	✓ Yes	✓ Yes	Not required
Tariff D – Demand	Tariff D comprises customers who consume more than 10 terajoules per annum. These customers are charged based on a capacity signal and are generally industrial facilities.	✓ Yes	✓ Yes	✓ Yes

This section describes the approach taken by Core Energy to prepare these forecast and the key drivers that influenced the forecasts. Further detail is provided in the Core Energy Group *Gas Demand Forecasts* Report, which is provided as Attachment 14.1.

14.4.1 Core Energy Approach

Core Energy has adopted a tailored approach for each customer class and forecast component (as outlined in Table 14.1) having regard for the individual drivers of each component. In summary, Core Energy's approach involves adjusting the observed trend decline in customer numbers and average consumption for the effects of factors not included in the historic trend, such as changes in retail gas prices. This approach is consistent with:

- the approach submitted to and accepted by the AER in respect of:
  - AGN's South Australian[121] and Queensland[122] networks for the current AA period; AGN's Victorian

[121] Envestra SA [Australian Gas Networks South Australia] Access Arrangement 2010/11 to 2015/16. Documents available on the AER website: http://www.aer.gov.au/node/9845

[122] Envestra QLD [Australian Gas Networks Queensland] Access Arrangement 2010/11 to 2015/16. Documents available on the AER website: http://www.aer.gov.au/node/5225

network[123]; and most recently Jemena Gas Network's (JGN) New South Wales network[124]; and

- the approach developed by ACIL Allen for AEMO, and employed by AEMO in its 2014 *National Gas Forecasting Report*.[125]

The approach adopted by Core Energy has enabled AGN to provide the AER with a detailed model clearly demonstrating how the demand forecasts were determined for each customer segment (see Attachment 14.2). This allows the AER to clearly understand and test the drivers of changes in volume over the next AA period.

Further detail on the approach is provided in Sections 14.4.1.1 (Tariffs R and C) and 14.4.1.2 (Tariff D). Section 14.4.2 provides an overview of the key assumptions underpinning the forecasts.

14.4.1.1 Forecasting Approach: Tariff R and Tariff C

As shown in Figure 14.2, Core Energy has relied upon the following approach to forecast Tariff R and Tariff C volume and customer numbers:

1. weather normalise historic demand using an Effective Degree Day (EDD) measure;
2. forecast the number of connections:
    - for Tariff R, sum together forecasts for existing connections, new electricity-to-gas connections, new estate and new medium-to-high density connections:
        - existing connections and new electricity-to-gas connections were forecast having regard to historic trends. A step-change adjustment was made to existing connections to account for the assumed removal of zero consuming meters (see Section 14.4.2.2); and
        - new dwelling (new estate and new medium-to-high density) connections were forecast having regard to independent forecasts of total new dwellings in South Australia from BIS Shrapnel and AGN's historic gas network penetration;

      the resultant forecasts were checked by Core Energy using a bottom-up forecasting approach, which referenced projections of population from the Australian Government;
    - for Tariff C, forecast the total number of connections (new and existing) having regard to the historic relationship between total connections and the Gross State Product (GSP) outlook for South Australia. A step-change adjustment was made to account for the assumed removal of zero consuming meters;
3. forecast consumption per connection separately for new and existing connections, having regard to the weather and price normalised historic growth in consumption per connection and adjusting for any new drivers, or change in drivers that are not included in this trend, such as movements in energy prices (gas and electricity) and the removal of zero consuming meters; and
4. multiply consumption per connection by connection numbers to forecast total demand for each of the residential and commercial sectors.

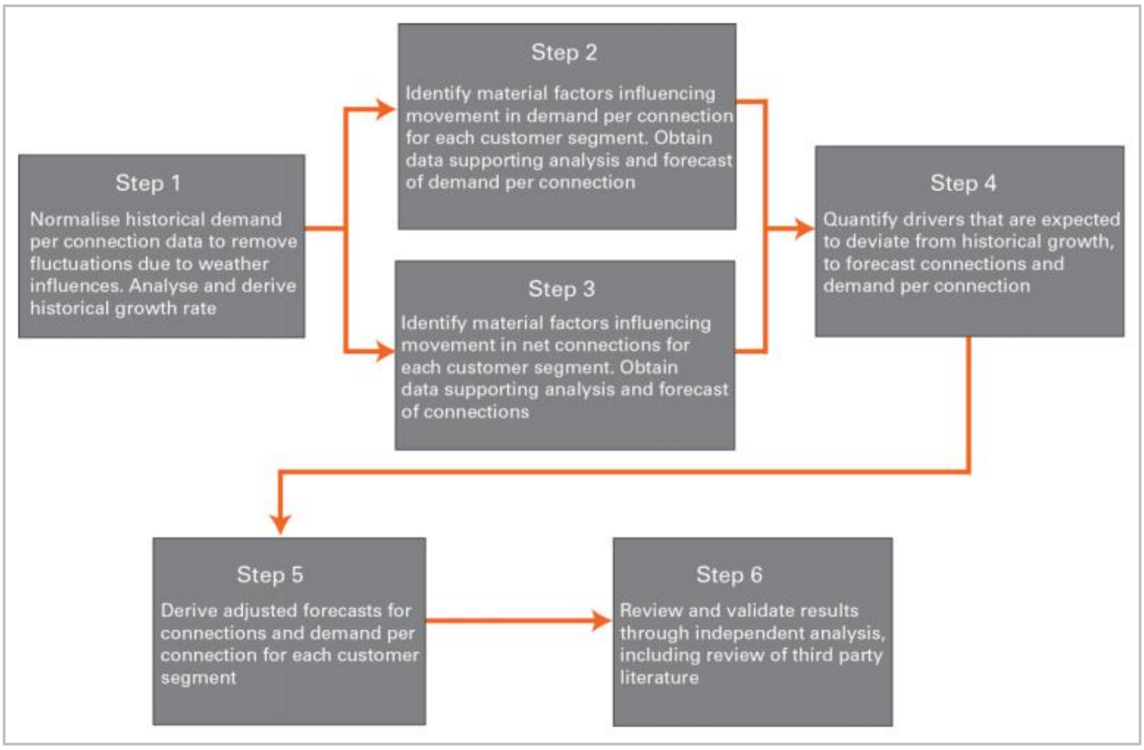
---

[123] Envestra Victoria [Australian Gas Networks] Access Arrangement 2010/11 to 2015/16. Documents available on the AER website: http://www.aer.gov.au/node/14473

[124] Jemena Gas Networks New South Wales Access Arrangement 2014/15 to 2019/20. Documents available on the AER website: http://www.aer.gov.au/node/24741

[125] ACIL Allen 2014, "*Report to Australian Energy Market Operator: Gas Consumption Forecasting - A Methodology*", June 2014.

FIGURE 14.2: CORE ENERGY GROUP FORECASTING APPROACH – TARIFFS R AND C



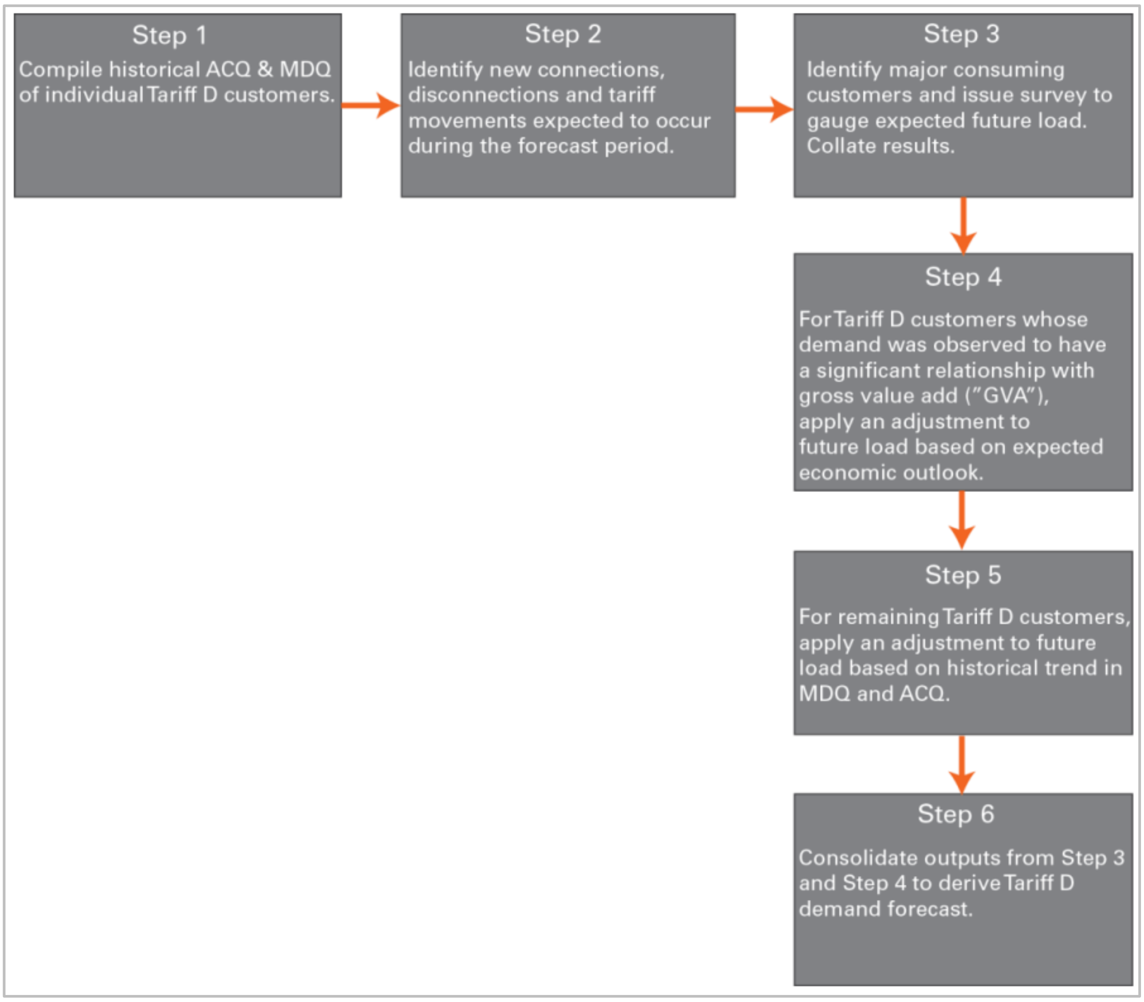
Source: Core Energy Group; Gas Demand Forecasts; June 2015.

14.4.1.2 Forecasting Approach: Tariff D

As shown in Figure 14.3, Core Energy has relied upon the following approach to forecast Tariff D MDQ and customer numbers:

1. forecast MDQ using actual MDQ as a starting point and adjusting for customer expansions and contractions, tariff reallocations, the economic outlook and efficiency trends; as informed by:
    - known expansions, contractions, new connections and disconnections informed by customers;
    - the results of a customer survey;
    - publicly available information such as media releases and energy efficiency reporting;
    - historic trends; and
    - BIS Shrapnel forecasts of GSP by industry segment;
2. forecast customer numbers having regard to historic trends, known movements and the results of a customer survey.

FIGURE 14.3: CORE ENERGY GROUP FORECASTING APPROACH – TARIFF D



Source: Core Energy Group; Gas Demand Forecasts; June 2015.

14.4.2 Key Core Energy Assumptions

The key assumptions and inputs into Core Energy's forecasts include: weather normalisation, the removal of zero consuming meters, forecasts of new dwellings and price elasticity.

14.4.2.1 Weather Normalisation

Gas demand, particularly in the residential sector, is materially impacted by weather. In times of cooler weather, gas consumption will be higher as people use more gas to heat their homes and water (and vice versa in times of warmer weather). It is therefore necessary to normalise Tariff R and C demand for weather in order to ensure the forecast starting point and historic trends relied upon in the forecasts are not unduly impacted by abnormal weather.

Core Energy weather normalised historic gas consumption data using an EDD measure that was developed based on AEMO's *2012 Weather Standards for Gas Forecasting* guidelines.[126] This approach is consistent with what was submitted to and accepted by the AER for JGN.[127]

---

126 AEMO 2012, "*2012 Review of the Weather Standards for Gas Forecasting*", April 2012.

127 Jemena Gas Networks New South Wales Access Arrangement 2015-20. Documents available on the AER website: http://www.aer.gov.au/node/24741

When determining what 'normal' weather is, Core Energy has considered expert analysis from the Commonwealth Scientific and Industrial Research Organisation (CSIRO), which analysis highlights that Australia's climate has been warming. More specifically CSIRO's *State of the Climate Report* notes that:

> *"Over the past 15 years, the frequency of very warm months has increased five-fold and the frequency of very cool months has declined by around a third, compared to 1951–1980."*[128]

and:

> *"Australian temperatures are projected to continue to increase, with more hot days and fewer cool days."*[129]

As mentioned earlier, in warmer temperatures AGN can expect lower gas consumption. To account for the historic and expected warming trends, Core Energy calculated the EDD based on a weather history going back 15 years (i.e. starting in 1999). This is not only consistent with the CSIRO analysis, but also consistent with the weather normalisation time period relied upon by AEMO in its *National Gas Forecasting Report* (see Attachments 14.1 and 14.3 for further information on Core Energy's approach to weather normalisation).

Table 14.2 summarises the resultant sensitivity of consumption to weather: it shows that for each EDD, Tariff R consumption will decline by 0.006 gigajoules per connection, compared to 0.089 gigajoules per connection for Tariff C.

TABLE 14.2: SENSITIVITY OF NATURAL GAS CONSUMPTION TO WEATHER

Class	Sensitivity Gigajoules per Connection per EDD
Tariff R	0.006
Tariff C	0.089

14.4.2.2 The Removal of Zero Consuming Meters

There are meters on our network for which there is no associated consumption. This situation may occur if a property is vacant or if supply has been cut off as a result of non-payment. As at 30 June 2014, there were approximately 6,900 zero consuming meters on the Network, the majority of which (around 85%) are residential meters. In March 2015, AGN received a request from a retailer to remove these meters from our networks.

Based on this precedent, Core Energy has assumed that all zero consuming meters are removed from the network over an 18 month period beginning 1 July 2015. This assumption impacts:

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

14.4.2.3 Forecasts of New Dwellings

The number of new residential connections expected over the next AA period is directly related to the forecast number of new dwellings in South Australia and the gas connection penetration rate. Core Energy has relied on independent forecasts of new dwellings from BIS Shrapnel as a basis for projecting new gas connections.

---

[128] CSIRO 2014, "*State of the Climate 2014*", 2014, pg. 4.

[129] CSIRO 2014, "*State of the Climate 2014*", 2014, pg. 15.

BIS Shrapnel rely on a multi-staged process to arrive at forecasts for new building activity in South Australia. This approach is outlined below, with further detail provided in Attachment 14.4:

1. identify the current stage of the building cycle using Australian Bureau of Statistics (ABS) data on building approvals and commencements;

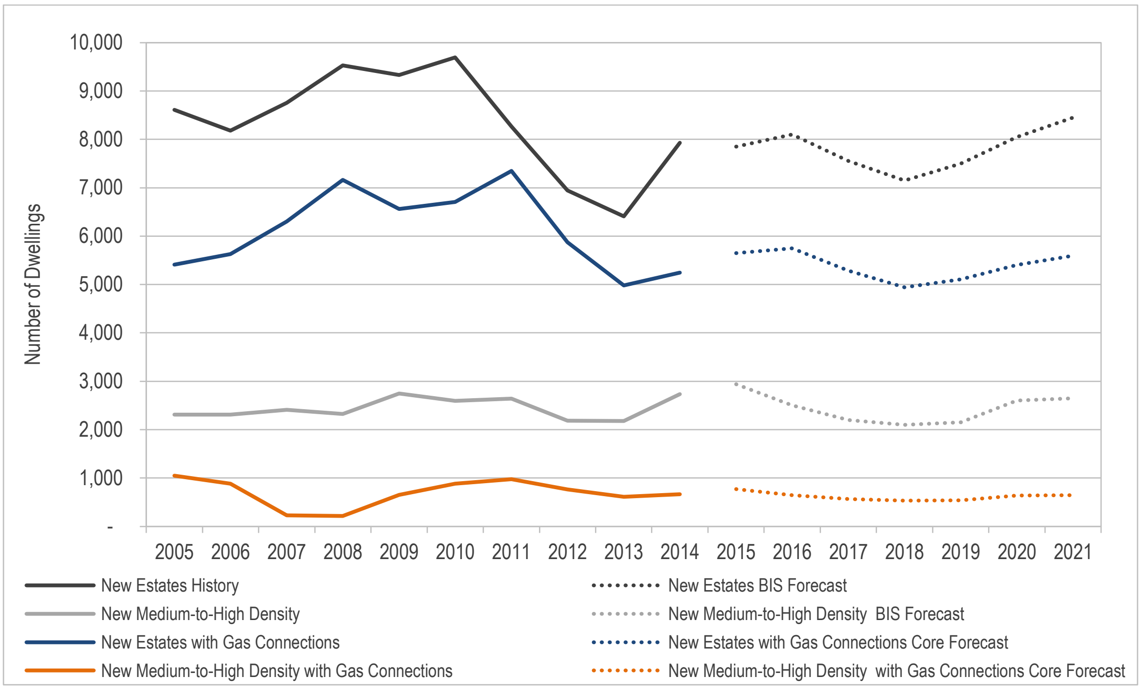
2. undertake demographic analysis to forecast long-run trends such as the underlying demand for and supply of new dwellings;

3. set the underlying economic assumptions and incorporate supporting cyclical data, such as, but not limited to, interest rates, price and rental data and employment; and

4. utilise residential project listings to add shape to forecasts through the identification of medium and high density developments.

As illustrated in Figure 14.4, on average over the forecast period (2015 through 2021) new dwellings starts in South Australia are expected to remain relatively consistent with recent (2014) dwelling starts. Figure 14.4 also shows the historic relationship between new dwellings and new gas customer connections. This relationship was used by Core Energy to develop forecasts of new dwellings with gas connections over the forecast period.

FIGURE 14.4: HISTORIC AND FORECAST NEW RESIDENTIAL DWELLINGS AND GAS-CONNECTED DWELLINGS



Section 2.2.1.1 of Core Energy's report provides further detail on Core Energy's approach to forecasting residential gas connections.

14.4.2.4 Price Elasticity

Projected retail gas and electricity prices impact on gas demand through application of a measure of price elasticity and cross-price elasticity:

- *own price elasticity* – which captures the impact of changes in gas prices on consumption per connection, accounting for not only the current year impact but also four years of lagged impacts reflecting that consumers will continue to respond to changes in gas price in the years following the initial change; and

- *cross-price elasticity* – which captures the impact of electricity prices on consumption per gas connection, accounting for the consumer response to the relative changes in gas and electricity prices, which for example results in the substitution of gas heating for heating by reverse-cycle air-conditioning (and vice versa).

Core Energy assumes:

- a lagged long-term own-price elasticity of -0.3 for residential customers and -0.35 for commercial customers; and
- a long-term cross-price elasticity of 0.1.

Core Energy's assumptions around own-price elasticity are consistent with that applied by the AER in its Final Decisions for AGN's South Australian, Queensland and Victorian networks and for JGN's New South Wales network.

Unlike own-price elasticity, cross-price elasticity has generally not been addressed widely in prior regulatory review processes. As outlined below, Core Energy suspect this is because the relative gas and electricity prices have not been sufficiently different in the past:

> *"Core acknowledges that cross price elasticity has not been addressed widely in prior AA reviews. Core believes this is due to the relative historical prices of gas and electricity not being sufficiently different to cause changes in demand over the regulatory time frame under consideration. However, Core is of the opinion that material changes in gas prices relative to electricity price are likely to occur during the Review Period and that it is reasonable to expect a cross-price demand response."* [130]

Additionally, cross-price elasticity or fuel substitution is also not considered by AEMO in its National Gas Forecasting Report, although AEMO do acknowledge that:

> *"Rapid technology changes and the relative pricing of gas and electricity fuel and appliances are expected to highly influence consumers' fuel selection over the forecast period [2014 to 2034]."* [131]
>
> and
>
> *"…[with respect to the impact of cross-price elasticity, also know as fuel substitution] AEMO expects that the drivers of customer connections to gas may change. This is being investigated for future reports."* [132]

In the absence of appropriate historic information, Core Energy has undertaken an extensive literature review to arrive at the long-term cross-price elasticity assumption of 0.10:

> *"Based on Core's analysis, an assumed long run elasticity of 0.10 for both residential and non-residential customers is deemed reasonable…"*[133]
>
> and

[130] Core Energy Group 2015,"*Gas Demand Forecasts – Annexure 4*", May 2015, pg. 90.

[131] AEMO 2014, "*Forecasting Methodology Paper – National Gas Forecasting Report 2014*", December 2014, pg. 16.

[132] AEMO 2014, "*Forecasting Methodology Paper – National Gas Forecasting Report 2014*", December 2014, pg. 18.

[133] Core Energy Group 2015,"*Gas Demand Forecasts – Annexure 4*", May 2015, pg. 90.

> *"Core's decision to use 0.1 was a result of comprehensive literature review and a careful assessment of energy market price trends. The overwhelming consensus centres on values between 0.1 and 0.2."*[134]

Core Energy's cross-price elasticity assumption is consistent with the JGN 2015 AA proposal.[135]

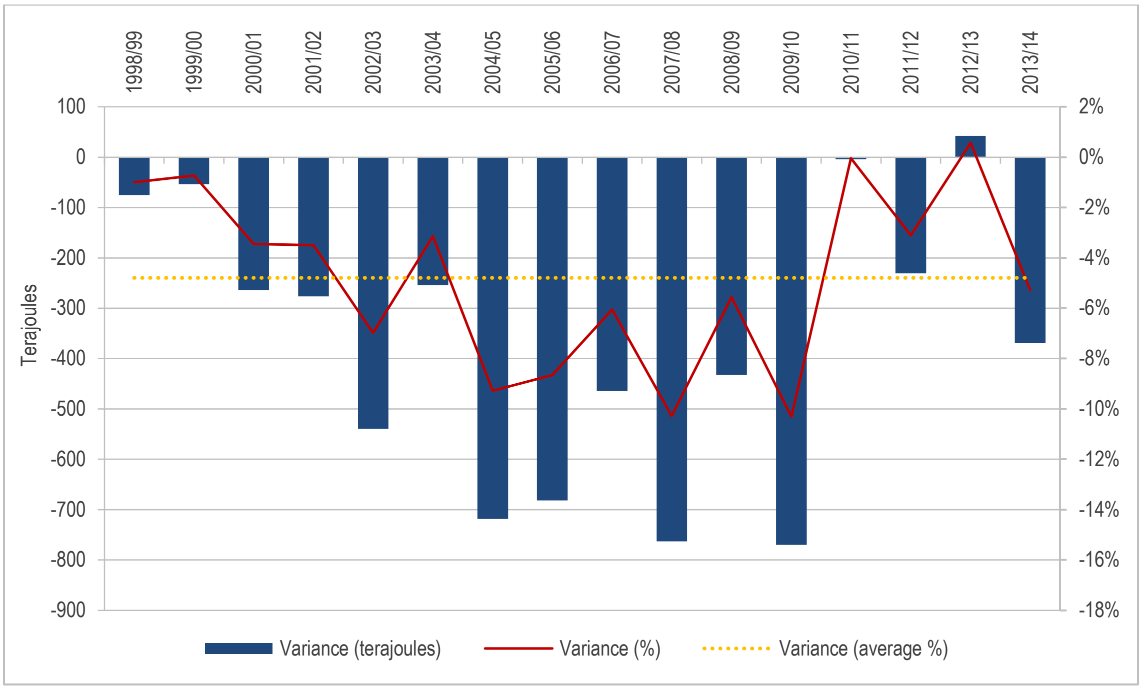
14.5 Tariff R – Residential Forecasts

14.5.1 Past Performance

Over the past 16 years, AGN has achieved (exceeded) the benchmark volumes set by the regulator for the residential sector only once. Figure 14.5 shows the variance between actual and benchmark volumes for the residential sector between 1998/99 (the commencement of the first AA period) and 2014 and highlights that, on average, actual volumes have been around 4.8% lower than the volumes set by the regulator.

As noted in Chapter 4, AGN estimates that the inability to achieve the volume benchmarks has led to actual revenue being $57 million less than the benchmark revenue set by the AER for the current AA period. This is primarily due to the residential sector which accounts for approximately 75% of AGN's total revenue recovery.

FIGURE 14.5: BENCHMARK AND ACTUAL RESIDENTIAL VOLUME VARIANCE, 1998/99 TO 2013/14



Note: Variance is calculated as actual less allowed (benchmark) consumption.

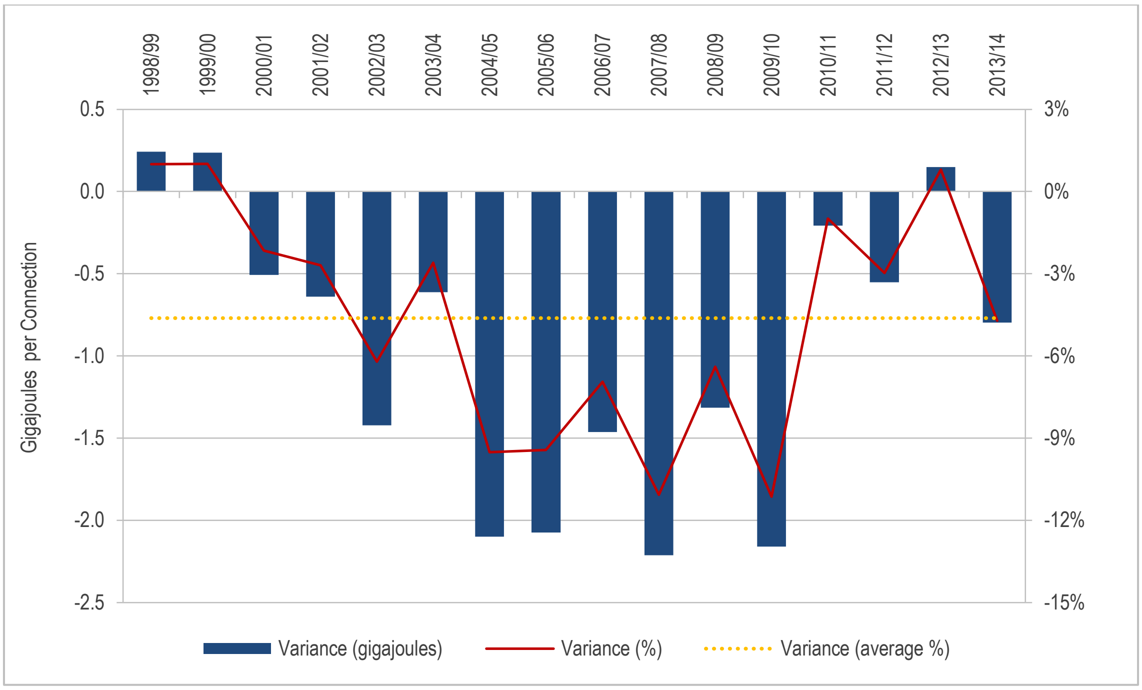
Historically, the primary reason for the difference between actual and benchmark volumes has been lower than allowed consumption per connection (Figure 14.6), which has more than outweighed any impact driven by connection numbers (Figure 14.7). AGN notes that over the current AA period, lower than benchmark residential connection numbers have also contributed to lower actual residential volumes.

---

134 Core Energy Group 2015,"*Gas Demand Forecasts – Annexure 4*", May 2015, pg. 90.

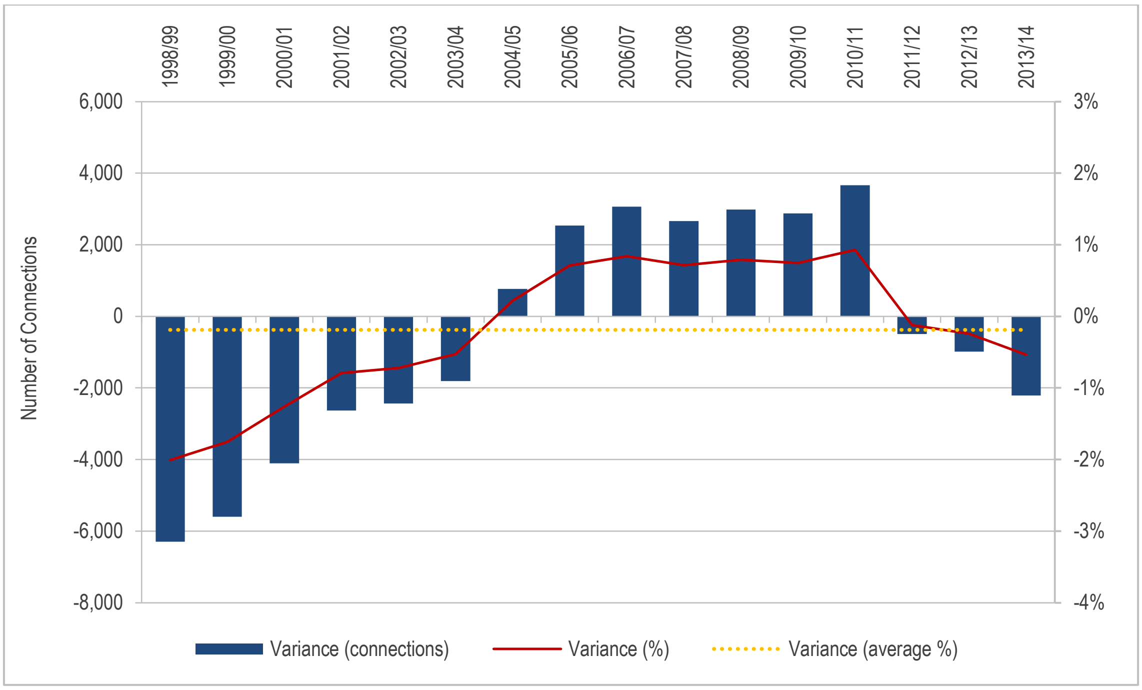
135 Jemena Gas Networks New South Wales Access Arrangement 2015-20. Documents available on the AER website: http://www.aer.gov.au/node/24741

FIGURE 14.6: BENCHMARK AND ACTUAL RESIDENTIAL CONSUMPTION PER CONNECTION VARIANCE, 1998/99 TO 2013/14



Note: Variance is calculated as actual less allowed (benchmark) consumption.

FIGURE 14.7: BENCHMARK AND ACTUAL RESIDENTIAL CONNECTION VARIANCE, 1998/99 TO 2013/14



Note: Variance is calculated as actual less allowed (benchmark) connections.

14.5.1.1 Connections

The data show that connection numbers have historically been growing at around 1.8% per annum. However, as illustrated in Figure 14.8, connection growth has been slowing since 2011, and for the first time since 1998/99, in 2012/13 the annual growth rate dropped below 1.7%. This trend continued in 2013/14, when the annual growth was 1.5%. There are a range of factors that contribute to the decline in connection numbers, all of which are expected to continue over the next AA period and include:

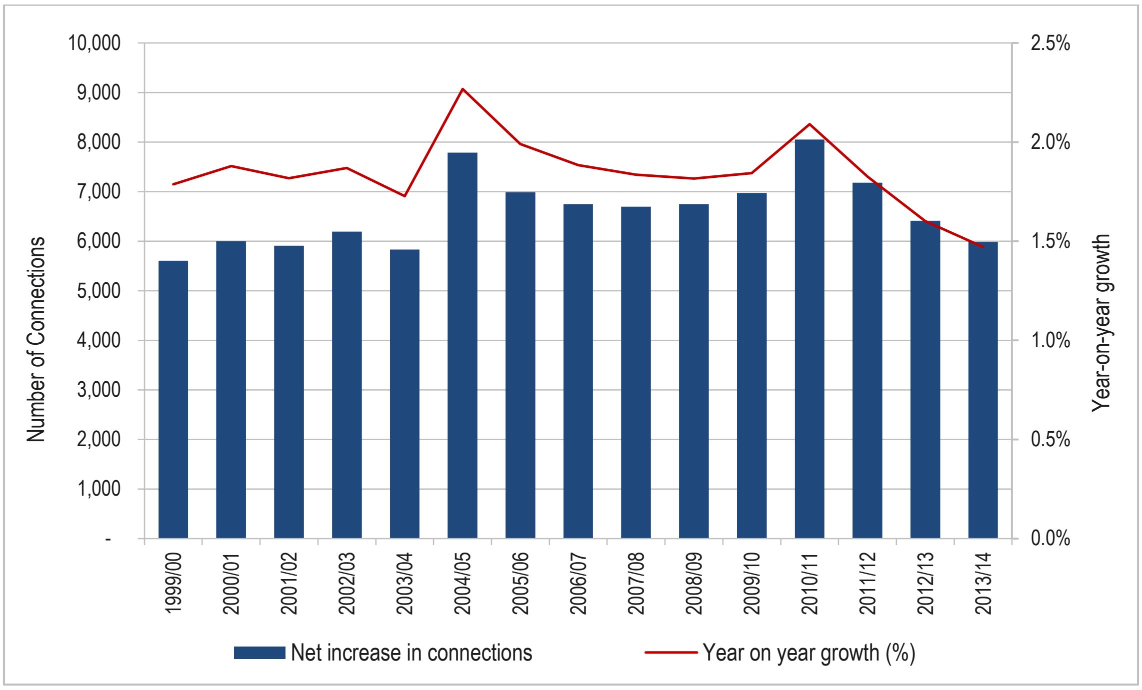
- the general building cycle; and
- the penetration of (and/or consumer preference towards) competing fuel sources such as electricity and solar.

Energy use trends and substitution can impact both consumption per connection and the number of connections (see Section 14.5.1.2).

It is noteworthy that in January 2014 the South Australian Water Heating Standards were amended to allow for the installation of smaller and medium size electric water heaters in houses that are not connected to reticulated gas. Previously, the standards required plumbers to install high efficiency gas, solar or electric heat pump systems only.[136]

This change may result in further declines in the number of gas connections; however, given the timing of the change, it is not possible to reliably substantiate the impact.

FIGURE 14.8: HISTORIC RESIDENTIAL CONNECTIONS



14.5.1.2 Consumption per Connection

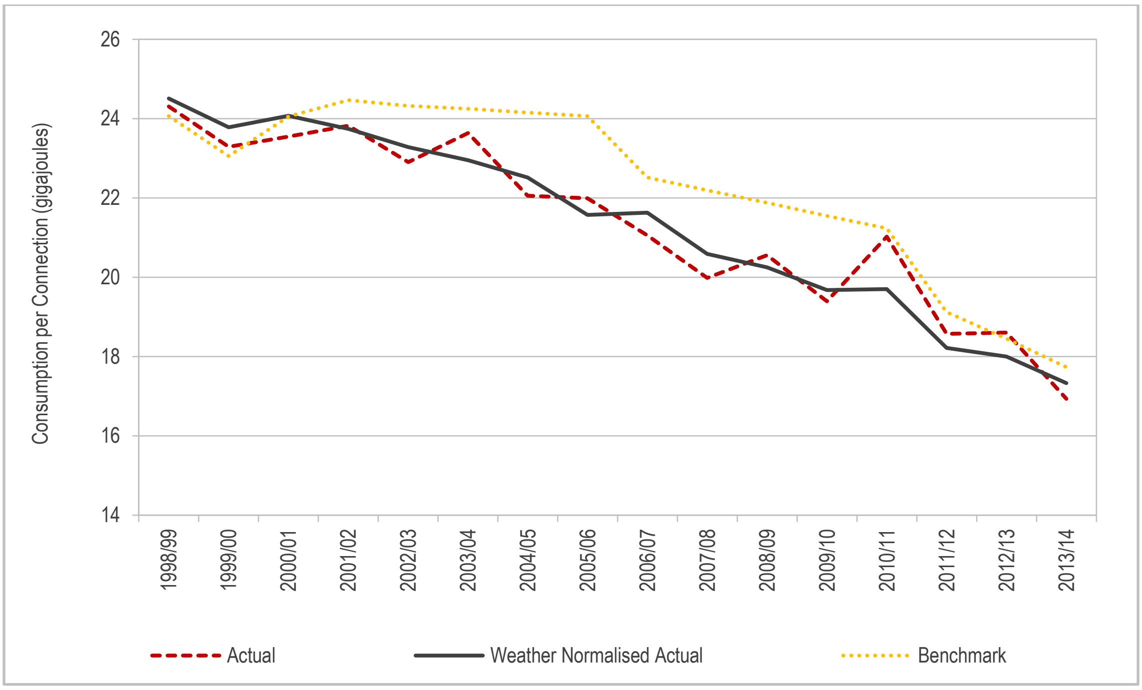
The data show that there has been a long-term trend decline in average consumption per residential connection (Figure 14.9). Average consumption has fallen from 24 gigajoules per connection in 1998/99 to less than 17 gigajoules in 2013/14. This is equivalent to an average annual rate of -2.2% per annum over the 1998/99 to 2013/14 period. Figure 14.9 also shows that consumption per connection has been:

- declining since 1998/99 on an actual and weather normalised basis; and
- declining at a faster rate more recently – for example, an average annual rate of -2.5% per annum over the 2008/09 to 2013/14 period and -3.0% over the 2010/11 to 2013/14 period.

---

[136] South Australian Government Website, https://www.sa.gov.au/topics/water-energy-and-environment/energy/saving-energy-at-home/household-appliances-and-other-energy-users/water-heating/water-heater-installation-requirements

FIGURE 14.9: HISTORIC RESIDENTIAL CONSUMPTION PER CONNECTION



There are a range of factors that have contributed to the decline in consumption per connection, all of which are expected to continue over the next AA period and include the features that follow:

- *energy use trends* – including gas appliance substitution:
  - the majority of gas used in South Australian (and Australian) households is for space heating, hot water heating and cooking, with space heating and hot water heating accounting for the largest volume of energy;
  - space heating and hot water heating are being substituted for their electric and solar equivalents, resulting in a decline in gas consumption per connection – for example, recent data released by the ABS shows that the percentage of South Australian households using gas as their primary source of heating in 2014 was 24.7%, which was 2.0% lower than in 2011 and 4.6% lower than in 2005, whilst the percentage of households using electricity has increased;[137,138,139]
    - additionally, the proportion of South Australian households using solar systems to heat water has increased to 8.1% in 2014 from 6.6% in 2011, whilst the proportion of homes using gas for the same purpose has remained relatively steady (48.4% in 2005, 49.6% in 2014);
    - it is noteworthy that the penetration of gas for hot water heating includes gas boosted systems which only operate when a solar system can not provide all the hot water required by a household – by definition these systems use less gas than traditional gas powered systems, also contributing to the declining trend;
- *warming weather* – as described earlier (see Section 14.4.2.1) the frequency of warm weather is increasing, whilst the frequency of cool weather is decreasing, driving lower consumption;

---

137 ABS 2014, "*4602.0.55.001 – Environmental Issues: Energy Use and Conservation, March 2014*", December 2014.

138 ABS 2011, "*4602.0.55.001 – Environmental Issues: Energy Use and Conservation, March 2011*", October 2011.

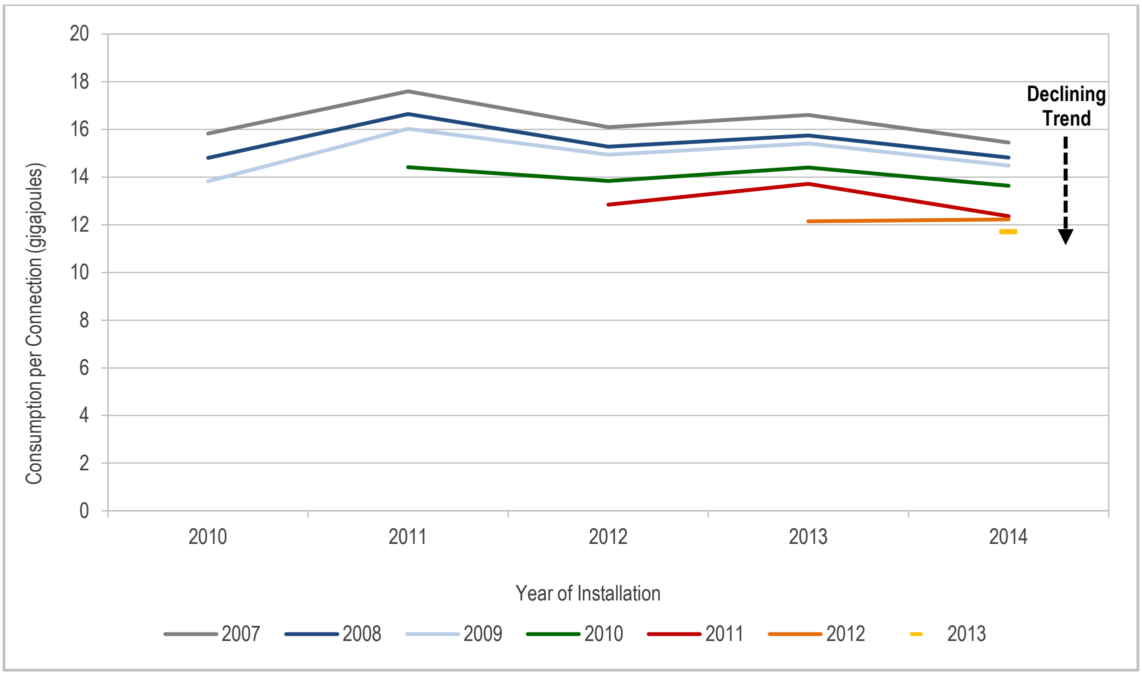
139 Note: ABS data is based on a survey completed in March of that year. As a result, the year references can be assumed to be correct as at March of that year.

- *increased appliance efficiency* – driven by the appliance efficiency requirements set out in government policy such as the Minimum Energy Performance Standards scheme;
- *spatial energy efficiency* – driven by government policy such as the Nationwide House Energy Rating Scheme, which sets out efficiency standards to which new dwellings must comply:
- *other government policy* – incentivising or dictating the use of renewable energy and/or energy efficient appliances. For example, the Renewable Energy Target, Water Efficiency Labelling and Standards and Restriction on High Emission Water Heaters;
- *price sensitivity* – since 2011, retail gas prices have increased on average by more than 10% per annum. Consumption is price sensitive, so these increases will have a resultant negative impact on gas usage (as described in Section 14.4.2);
- *consumer preferences and behaviour* – the incentives and decision making process by consumers in relation to energy use appears to be changing, with an increased focus on energy savings and a commitment to saving the environment:
  - The Australian Housing and Urban Research Institute conducted a survey to understand the reasons behind changes in energy use in households in Melbourne and Brisbane. The survey found that:[140]
    - over 60% of respondents in both cities changed their energy use due to a new awareness of how to achieve reduced energy consumption; and
    - more than 45% of Brisbane respondents and more than 52% of Melbourne respondents cited environmental benefits as a driver for their change in behaviour;
  - it is reasonable to assume that South Australian household behaviour would be similar to those tested in Melbourne and Brisbane and that these households are also actively switching appliances and changing behaviour to increase efficiency and protect the environment (for example, by relying on solar energy and/or 'switching-off' (for example taking shorter showers);
- *connection of new customers* – customers in new homes consume less on average than customers in existing homes. This results from new homes having more energy efficient building design and appliances and because they have fewer gas appliances (for example, no space heating). There has also been a decline in the number of people per dwelling with the ABS projecting that over the next AA period, the number of lone-person households in South Australia will increase from 28% in 2015 to 29% of all households in 2021.[141] This is illustrated in Figure 14.10, which shows that new customer connections consistently consume less than existing connections.

140 Note participants could cite multiple reasons for changing behavior.

141 ABS 2015, "*3236.0 – Household and Family Projections, Australia, 2011 to 2036*", Table 1.11 – Series II, March 2015.

FIGURE 14.10: ACTUAL AVERAGE RESIDENTIAL CONSUMPTION PER CONNECTION BY YEAR OF INSTALLATION

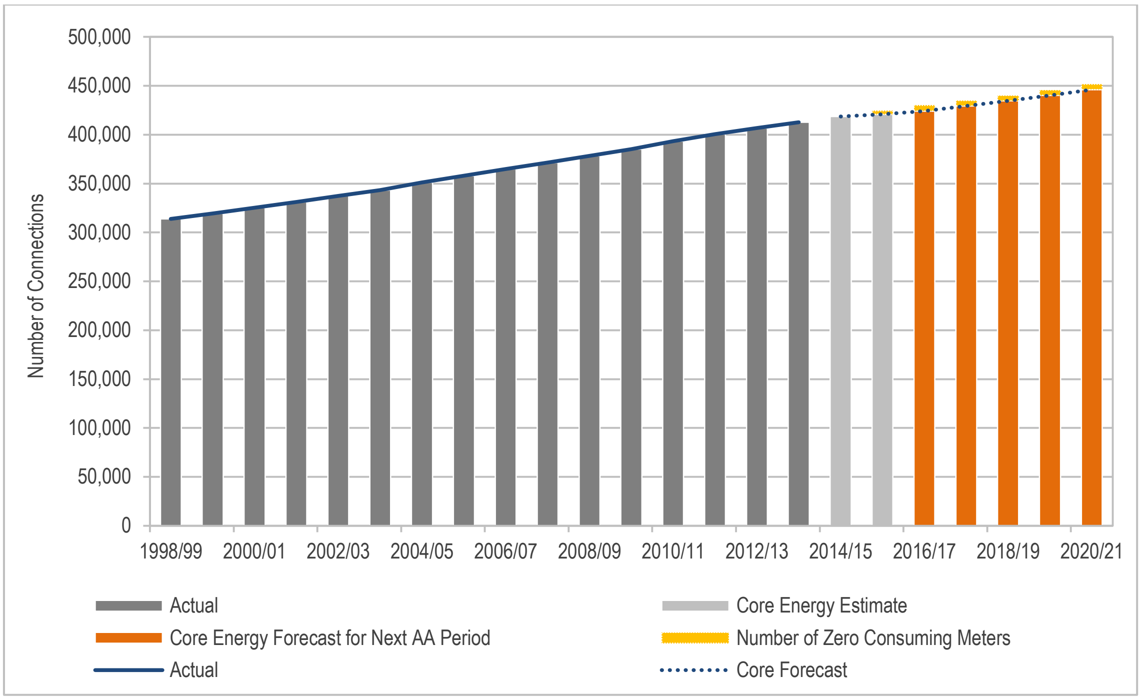


14.5.2 Connection Number Forecasts

Residential connections are forecast to increase by 1.2% per annum over the next AA period, which is lower than recent rates of 1.5% per annum (one-year and two-year rates) and lower than the five-year rate of 1.8% per annum. The slowing in customer growth reflects the subdued new housing market in South Australia over the next AA period and is consistent with recent trends of slowing connection growth (see Figure 14.8). The primary drivers of the forecast are:

- the number of new dwellings as sourced from BIS Shrapnel, which forecast declining growth in new dwellings in South Australia over the first half of the total forecast period (2014/15 to 2017/18) (see Figure 14.4);
- the assumed penetration of natural gas into new dwellings, which forecast declining gas penetration rates consistent with recent history, reflecting a continued trend of consumer preference towards solar and electricity; and
- the assumption that zero consuming meters will be removed based on a retailer request to remove meters for which there is no associated consumption, noting that zero consuming meters accounted for 1.4% of total connections in 2014).

FIGURE 14.11: RESIDENTIAL CONNECTION NUMBER FORECAST

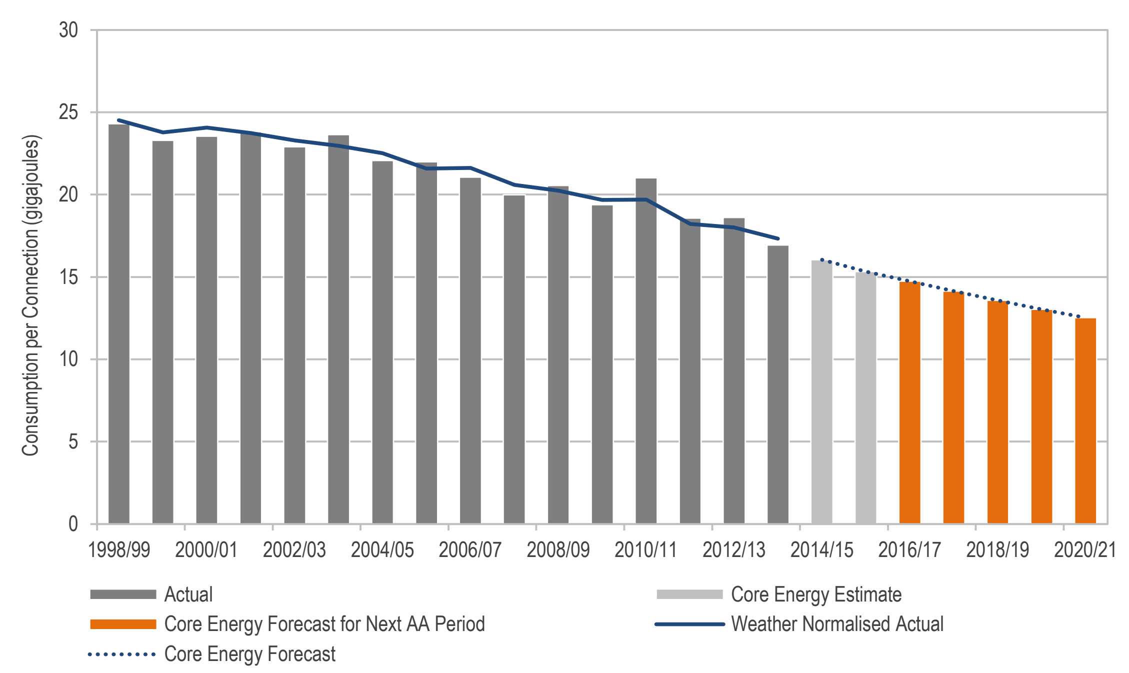


14.5.3 Average Consumption Forecasts

Weather-normalised residential consumption per connection is forecast to decrease from 15 gigajoules at the start of the next AA period to around 13 gigajoules in 2021. This is equivalent to an average annual rate of -4.0% per annum over the next AA period, which is consistent with recent rates (one-year rate of -3.7% and 4.2% over 2011/12 to 2013/14) and above the rate over the past five years (-3.0% over 2009/10 to 2013/14). The primary drivers of the forecast are:

- the underlying average annual decline resulting from existing factors, as outlined in Section 14.5.1.2 (excluding price sensitivity which is dealt with separately – see below); and
- adjustments for own and cross-price sensitivity resulting from changes in gas and electricity price, noting that in determining the underlying average annual decline in consumption, Core Energy first normalised for price to account for the timing of price changes.

FIGURE 14.12: RESIDENTIAL CONSUMPTION PER CONNECTION FORECAST



Note: The removal of zero consuming meters not only results in a reduction in connection numbers, but also an increase in consumption per connection (ultimately the adjustment has a zero net impact on total demand [calculated as the product of consumption per connection and number of connections]. This has been incorporated into the Core Energy forecasts, but is not separately shown in Figure 14.12 due to its relatively small impact on the consumption per connection forecast.

14.5.4 Final Residential Demand Forecasts

The final residential demand forecasts are a combination of Core Energy's customer number and average consumption forecasts (see Table 14.3). Total demand (or consumption) is forecast to decline at a rate of 2.8% per annum over the next AA period. Whilst this forecast reflects Core Energy's best estimate of future consumption, there are several factors that Core Energy were not able to quantify which may result in lower than expected residential consumption, for example:

- the potential emergence of new technology such as battery storage and electric vehicles, which could result in customers choosing electric appliances over their gas equivalents:
  - in an assessment for SA Power Networks (SAPN), Energeia forecast that battery storage will emerge as a new energy source from 2019.[142] This is consistent with recent media relating to the launch of Tesla's battery for sale in 2016 as well similar launches by energy retailers such as AGL[143]
- the impact of cost-reflective electricity tariffs which were introduced by SAPN in July 2014 and will be progressively rolled-out to new and altered connections from July 2017:[144]
  - capacity based tariffs encourage customers to consume more electricity during off-peak times, which for electricity is in the winter months, coinciding with peak gas consumption. This is likely to result in an increase in the use of electricity for space and water heating, and

---

142 SA Power Networks 2014, "*Regulatory Proposal 2015-2020*", October 2014, Chapter 5.

143 Financial Review 2015, "*Australia primed as heartland for battery-storage revolution*", 29 May 2015.

144 SA Power Networks 2014, "*Regulatory Proposal 2015-2020*", October 2014, Chapter 14.

- the impact of the change to water heating policy for homes with no current gas connection (as described earlier in Section 14.5.1.1.

TABLE 14.3: RESIDENTIAL DEMAND FORECAST

	2016/17	2017/18	2018/19	2019/20	2020/21
Customer Numbers	424,321	429,376	434,603	440,208	446,004
Consumption per Connection (gigajoules)	14.7	14.1	13.6	13.0	12.5
Demand (terajoules)	**6,259**	**6,072**	**5,898**	**5,374**	**5,584**

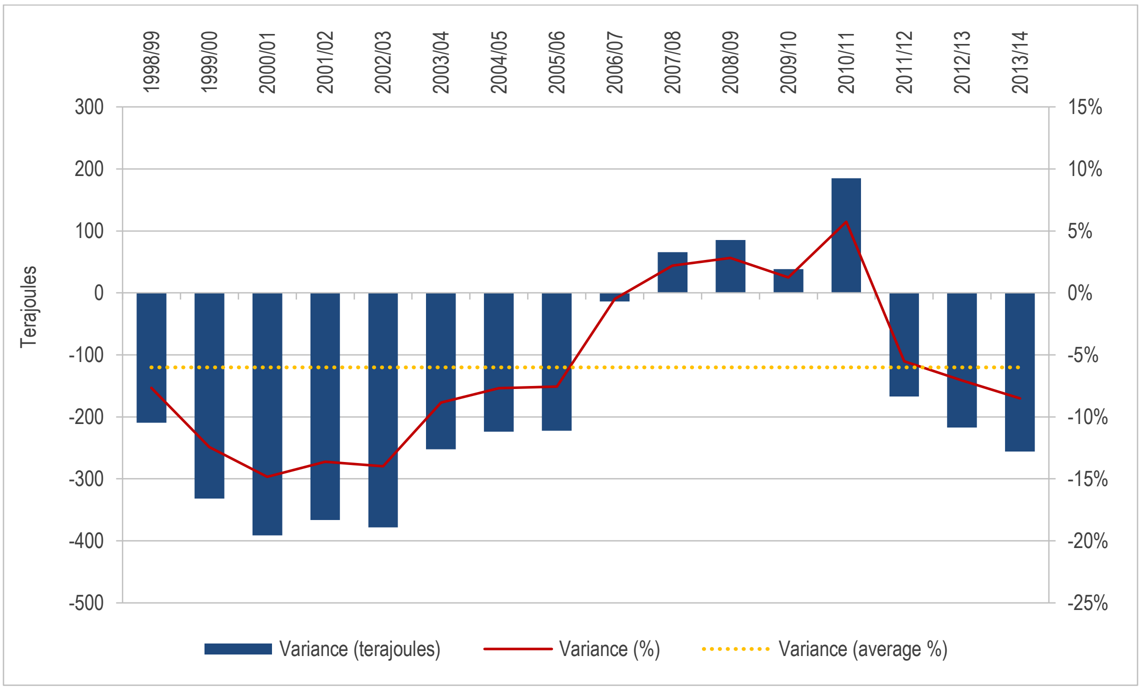
14.6 Tariff C – Commercial Forecasts

14.6.1 Past Performance

Trends in the past performance in commercial consumption are similar to that for the residential sector. As outlined in Figure 14.13, over the past 16 years AGN has achieved (exceeded) the benchmark volumes set by the regulator only four times and has been, on average, 6.0% below benchmark levels.

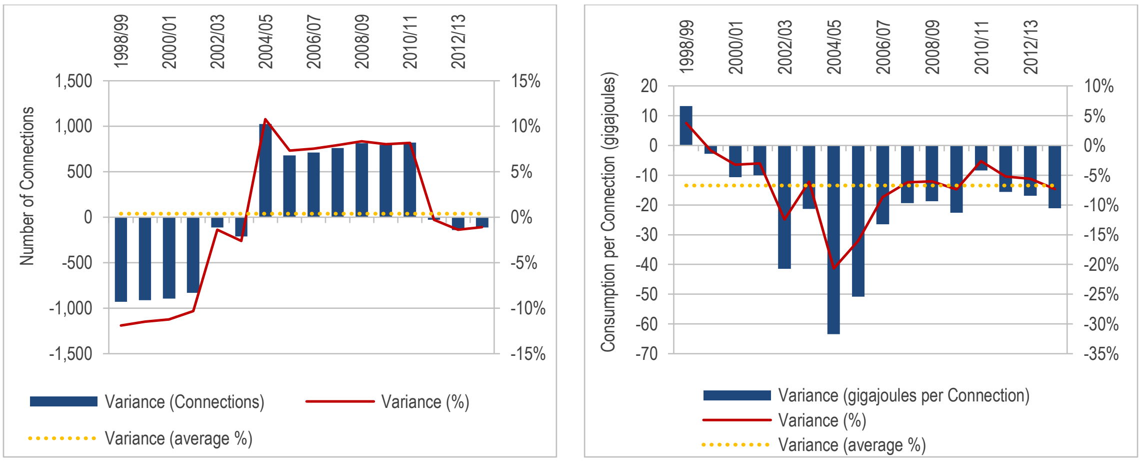
Similar to residential consumption, the inability to achieve the commercial benchmark volumes is primarily driven by an inability to achieve the consumption per connection benchmarks, with the current AA period performance also being exacerbated by lower than benchmark connection numbers (see Figure 14.14).

FIGURE 14.13: BENCHMARK AND ACTUAL COMMERCIAL VOLUME VARIANCE, 1998/99 TO 2013/14



Note: Variance is calculated as actual less allowed (benchmark) consumption.

FIGURE 14.14: BENCHMARK AND ACTUAL COMMERCIAL COMPONENT VARIANCE, 1998/99 TO 2013/14



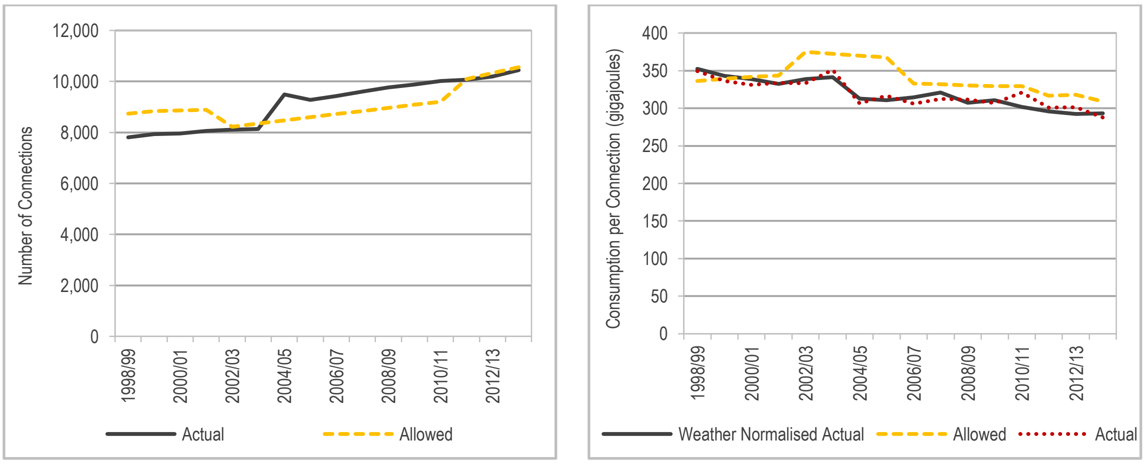
Note: Variance is calculated as actual less allowed (benchmark)connections (left hand-chart) or allowed (benchmark) consumption per connection right hand-chart.

The data show that, historically, growth in commercial connections is more variable than residential connections partly driven by the sector's relationship to economic activity. Whilst more variable, the number of commercial connections has grown at an average annual rate of 2.0% over the 1998/99 to 2013/14 period.

Similar to residential consumption per connection, commercial consumption per connection data shows that there has been a long-term declining trend. Average consumption has fallen from 349 gigajoules per connection in 1998/99 to 288 gigajoules in 2013/14. This is equivalent to an average annual rate of -1.2% per annum over the 1998/99 to 2013/14 period.

The drivers of the decline in commercial consumption per connection are similar to those described for the residential sector, including energy use trends, warming weather, increased energy efficiency, government policy and price sensitivity.

FIGURE 14.15: BENCHMARK (ALLOWED) AND ACTUAL COMMERCIAL COMPONENT PERFORMANCE, 1998/99 TO 2013/14



14.6.2 Connection Number Forecasts

Commercial connection numbers are forecast to increase by 0.9% per annum over the next AA period. The primary drivers of the forecast are:

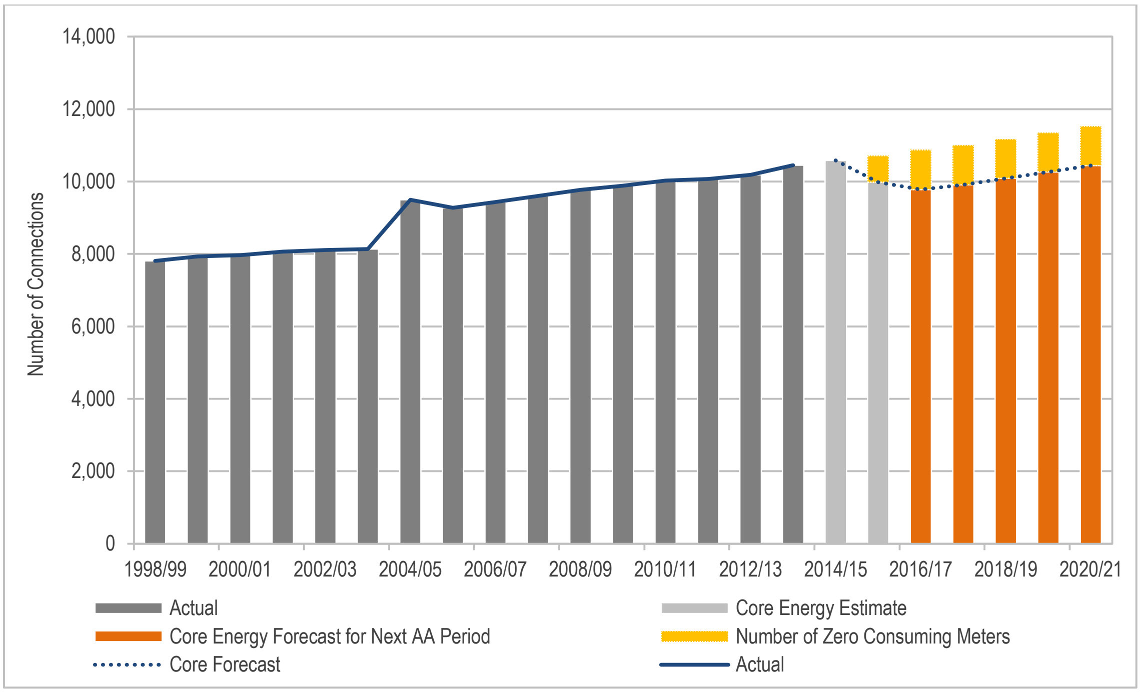
- the economic outlook for the state, as measured by GSP; and
- the assumption that zero consuming meters will be removed.

The assumed removal of zero consuming meters (as described in Section 14.4.2.4) is a step change outside of the historic trend based on a retailer request to remove meters for which there is no associated consumption. Figure 14.16 shows that had the request to remove zero consuming meters not been made, forecast growth in commercial connections over the next AA period would have been around 1.5% per annum, slightly faster than the rate of growth over the past five years (1.3% per annum from 2008/09 to 2013/14).

The underlying (prior to the zero consuming meter adjustment) growth in commercial connections is driven by forecast economic activity in the state. Core Energy found there to be a statistically significant relationship between GSP and commercial connections. The identified relationship implies that for every 1.0% increase in GSP in the previous year, commercial connections will increase by 0.285%. GSP is forecast to increase from 1.3% in 2013/14, to 2.1% in 2020/21.[145]

It is noteworthy that over the current AA period, GSP was a material driver of our inability to achieve benchmarks volumes for Tariff C. More specifically, the actual GSP over the 2011/12 to 2013/14 period has been, on average, 1.2% which is significantly less than average GSP of 2.9% assumed in the benchmarks. This highlights the importance of sourcing reasonable forecasts of GSP (Core Energy rely upon forecasts from BIS Shrapnel, adjusted for activity outside of AGN's gas distribution network).

FIGURE 14.16: COMMERCIAL CONNECTION NUMBER FORECAST



14.6.3 Average Consumption Forecasts

Weather-normalised commercial consumption per connection is forecast to decrease from 288 gigajoules at the start of the next AA period to 263 gigajoules by 2021. This is equivalent to an average annual rate of -1.8% per annum over the next AA period. The primary drivers of the forecast are:

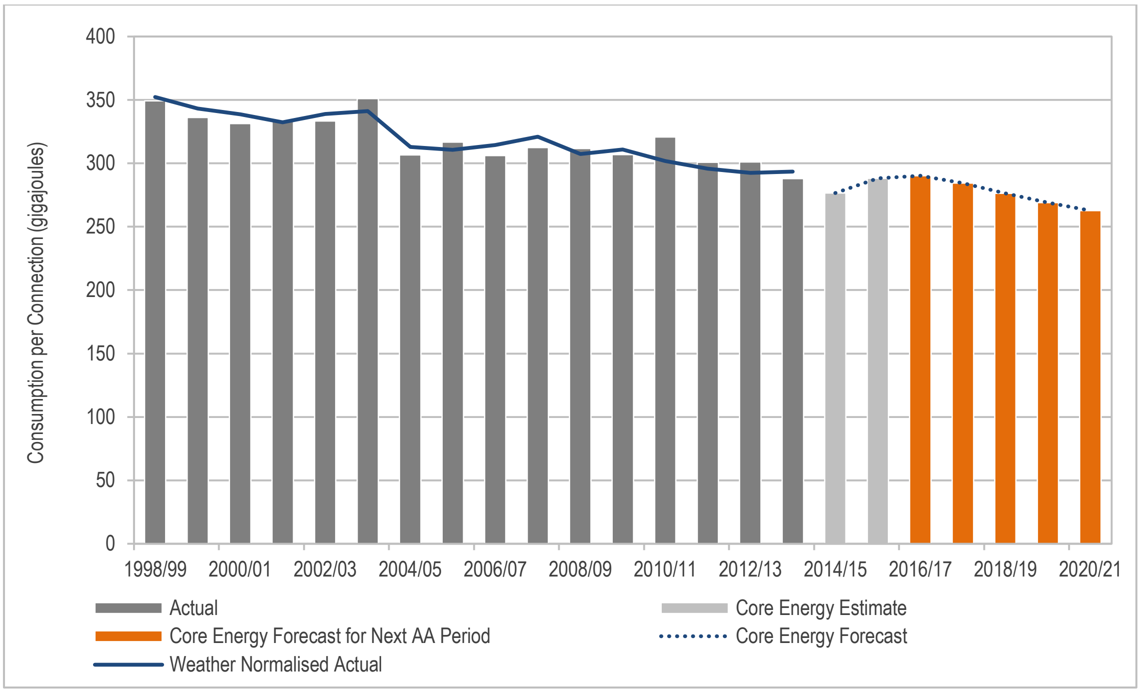
- the underlying average annual decline resulting from existing factors, as outlined in Section 14.5.1.2 (excluding price sensitivity which is dealt with separately – see below);
- the impact of the removal of zero consuming meters, which results in an increase in consumption per connection for the remaining connections; and

---

145 GSP forecasts have been sourced from BIS Shrapnel and adjusted by Core Energy to remove the impact of the Olympic Dam Project, which is outside of AGN's distribution network.

- adjustments for own and cross-price sensitivity resulting from changes in gas and electricity prices, noting that in determining the underling average annual decline, Core Energy first normalised for price to account for the timing of price changes and to ensure there was no double counting.

FIGURE 14.17: COMMERCIAL CONSUMPTION PER CONNECTION FORECAST



14.6.4 Final Commercial Demand Forecasts

The final commercial demand forecast is a combination of Core Energy's connection number and average consumption forecasts (see Table 14.4). Total demand (or consumption) is forecast to remain relatively flat over the next AA period as the decline in consumption per connection (driven by price sensitivity) balances any growth in connection numbers.

TABLE 14.4: COMMERCIAL DEMAND FORECAST

	2016/17	2017/18	2018/19	2019/20	2020/21
Customer Numbers	9,781	9,913	10,086	10,261	10,439
Consumption per Connection (gigajoules)	290.2	284.5	276.4	269.0	262.7
Demand (terajoules)	**2,839**	**2,820**	**2,788**	**2,760**	**2,742**

14.7 Tariff D – Demand Forecasts

Tariff D Demand customers comprise AGN's largest network users and use more than half of the total gas delivered by AGN in South Australia.

14.7.1 Connection Numbers

Tariff D connection numbers are forecast to decrease by 15 customers, from 125 at the start of the next AA period to 110 in 2021. This is less than the expected decline in customer numbers over the current AA period which is estimated to be more than 20 by the end of the current AA period. The primary drivers of the forecast are:

- the results of a survey of AGN's largest users;

- known movements (existing connection load changes (expansions and contractions), disconnections and new connections) that have been reported to AGN by the customer themselves;
- assumed disconnections resulting from publicly available information on the health system reforms and the closure of the car industry; and
- analysis of the historic trend.

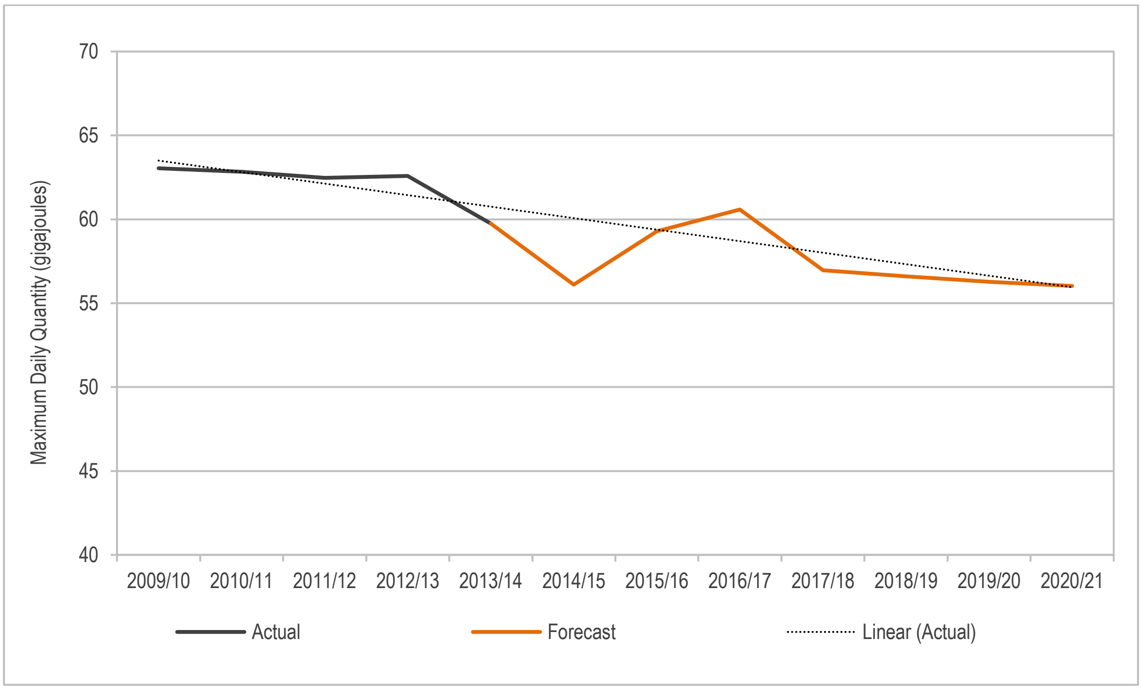
14.7.2 Demand

Tariff D MDQ is forecast to decrease from 59 gigajoules at the start of the next AA period to 56 gigajoules in 2020/21. This is equivalent to an average annual rate over the next AA period of -1.1% per annum, similar to the rate over the past five years (2008/09 to 2013/14).The primary drivers of the forecast are:

- growth in MDQ resulting from announced expansions and new developments; being offset by
- reductions in load arising from the closure of several facilities in the near-term.

Figure 14.18 shows the magnitude of each forecast component in each year of the total forecast period. It also shows that the overall decline in MDQ is consistent with recent history, reflecting the continued challenging business conditions for large industrial customers.

FIGURE 14.18: TARIFF D MDQ DRIVERS AND OUTLOOK



14.8 Summary

Core Energy has developed best estimate of demand forecasts that have been arrived at on a reasonable basis, as required by Rule 74 of the NGR. These forecasts (outlined in Table 14.5) reflect recent declining trends in consumption driven by the impact of energy conservation and efficiency, energy source substitution, customer response to changes in energy (gas and electricity) prices and subdued economic conditions. Core Energy has developed these forecasts by applying the same principles/methods used by AEMO in its National Gas Forecasting Report.

TABLE 14.5: FINAL DEMAND AND CUSTOMER NUMBER FORECASTS, 2016/17 TO 2020/21

	2016/17	2017/18	2018/19	2019/20	2020/21
Residential Tariff R					
Customer Numbers	424,321	429,376	434,603	440,208	446,004
Demand (terajoules)	6,259	6,072	5,898	5,374	5,584
Commercial Tariff C					
Customer Numbers	9,781	9,913	10,086	10,261	10,439
Demand (terajoules)	2,839	2,820	2,788	2,760	2,742
Tariff D					
Customer Numbers	125	118	115	113	110
Demand (terajoules MDQ)	61	57	57	56	56

Table 14.6 details the gross connection forecasts over the next AA period. These forecasts are taken directly from Core Energy's forecast model and are used by AGN in developing the capex program, particularly in forecasting capex related to customer growth.

TABLE 14.6: GROSS CONNECTION FORECASTS, 2016/17 TO 2020/21

	2016/17	2017/18	2018/19	2019/20	2020/21
New Homes	4,886	4,592	4,781	5,093	5,306
Existing Homes	1,435	1,435	1,435	1,435	1,435
New Medium-to-High Density Dwellings	498	464	463	547	544
Commercial and Industrial	260	229	272	277	281
Total	**7,079**	**6,720**	**6,952**	**7,352**	**7,566**

Ancillary Reference Services comprise services provided by AGN for special meter reads, disconnections, reconnections, meter and gas installation tests, meter removal and meter reinstallation. These forecasts are based on an estimate of 2014/15 data and are summarised in Table 14.7.

TABLE 14.7: ANCILLARY REFERENCE SERVICE FORECASTS, 2016/17 TO 2020/21

	2016/17	2017/18	2018/19	2019/20	2020/21
Disconnection	6,576	6,655	6,737	6,824	6,915
Reconnection	4,950	5,009	5,071	5,137	5,205
Special Meter Read	126,815	128,329	129,906	131,593	133,337
Meter Removal	1,463	1,463	1,463	1,463	1,463
Meter Reinstallation	73	73	73	73	73
Meter Gas and Installation Test	123	123	123	123	123
Total	**140,000**	**141,652**	**143,373**	**145,213**	**147,116**

Note: Totals may not sum due to rounding.

Page intentionally left blank

15 Reference Tariffs

Page intentionally left blank

15 Reference Tariffs

15.1 Introduction

Chapter 13 described the benchmark total revenue that Australian Gas Networks Limited (AGN) can recover for each year of the next (2016/17 to 2020/21) Access Arrangement (AA) period. AGN recovers this revenue by charging Haulage Reference Tariffs and Ancillary Reference Tariffs to customers connected to the South Australian natural gas distribution network (the Network). This chapter details the proposed tariffs to apply over the next AA period, including explaining how those tariffs comply with the requirements of the National Gas Rules (NGR).

15.2 Requirements of the National Gas Rules

Rule 93 of the NGR imposes the following requirements on AGN regarding the allocation of revenue and costs to reference services:

> *"(1) Total Revenue is to be allocated between reference and other services in the ratio in which costs are allocated between reference and other services.*
>
> *(2) Costs are to be allocated between reference and other services as follows:*
>
> *(a) costs directly attributable to reference services are to be allocated to those services; and*
>
> *(b) costs directly attributable to pipeline services that are not reference services are to be allocated to those services; and*
>
> *(c) other costs are to be allocated between reference and other services on a basis (which must be consistent with the revenue and pricing principles) determined or approved by the AER [Australian Energy Regulator]."*

Rule 94, as outlined below, imposes the following requirements on AGN with regards to tariffs:

> *"(1) For the purpose of determining reference tariffs, customers for reference services provided by means of a distribution pipeline must be divided into tariff classes.*
>
> *(2) A tariff class must be constituted with regard to:*
>
> *(a) the need to group customers for reference services together on an economically efficient basis; and*
>
> *(b) the need to avoid unnecessary transaction costs.*
>
> *(3) For each tariff class, the revenue expected to be recovered should lie on or between:*
>
> *(a) an upper bound representing the stand alone cost of providing the reference service to customers who belong to that class; and*
>
> *(b) a lower bound representing the avoidable cost of not providing the reference service to those customers.*
>
> *(4) A tariff, and if it consists of 2 or more charging parameters, each charging parameter for a tariff class:*
>
> *(a) must take into account the long run marginal cost for the reference service or, in the case of a charging parameter, for the element of the service to which the charging parameter relates;*
>
> *(b) must be determined having regard to:*
>
> *(i) transaction costs associated with the tariff or each charging parameter; and*

> *(ii) whether customers belonging to the relevant tariff class are able or likely to respond to price signals.*
>
> *(5) If, however, as a result of the operation of subrule (4), the service provider may not recover the expected revenue, the tariffs must be adjusted to ensure recovery of expected revenue with minimum distortion to efficient patterns of consumption.*
>
> *(6) The AER's discretion under this rule is limited."*

15.3 Stakeholder Engagement

As explained in Chapter 3, AGN undertook a stakeholder engagement program to inform the initiatives set out in this Access Arrangement Information (AAI). This engagement program included deliberative stakeholder workshops, dedicated meetings with large customers and consumer/business advocacy groups and through the AGN Reference Group and Retailer Reference Group (comprising representatives from retailers who supply the South Australian market).

One of the topics included in our stakeholder engagement program was our Reference Tariffs, including the number, structure and level of those tariffs. For example, AGN held a series of workshops on tariff structures with our Retailer Reference Group and held several dedicated meetings with the tariff teams of those retailers. AGN also asked workshop participants whether they have a preference between fixed or variable tariffs.

Overall, the feedback was that stakeholders were satisfied with the current Reference Tariffs, their structure and relative levels, but that AGN should continue to engage on Reference Tariffs over the next AA period (including as part of the annual variation to Reference Tariffs).

AGN supports this outcome and is not otherwise aware of any reasons as to why the current Reference Tariffs are not efficient. AGN has therefore proposed to apply Reference Tariffs that are consistent with that approved by the Australian Energy Regulator (AER) to apply over the current (2011/12 to 2015/16) AA period. The remainder of this chapter explains the derivation of our Reference Tariffs to apply over the next AA period, including how those tariffs comply with the relevant requirements of the NGR.

15.4 Allocation of Total Revenue and Costs

The costs set out in this AAI, particularly those set out in Chapters 7 (Operating Expenditure) and 8 (Capital Expenditure), relate to the provision of Haulage Reference Services (HRS) and Ancillary Reference Services (ARS), which are collectively referred to as Reference Services. The costs incurred in providing Non-reference Services are directly incurred and recovered from the particular customer that requested the service, and as such, are not included in this AAI.

As explained in Chapter 13, the costs incurred by AGN of providing ARS are directly recovered from the customers requesting the service. ARS forms approximately 1% of the total revenue to be recovered from customers. The remaining revenue is allocated to HRS, which services are explained in Chapter 16 and include:

- *Demand Haulage Service* – this service provides for the delivery of gas to Delivery Points (DPs) with an annual consumption that is equal to or greater than 10 terajoules per year;
- *Domestic Haulage Service* – this service provides for the delivery of gas to DPs where gas is used primarily for domestic purposes; and
- *Commercial Haulage Service* – this service applies to all DPs that are not Demand DPs or Domestic DPs.

AGN has developed a cost allocation model (CAM) to allocate revenue to the above HRS. The CAM, which is provided as Attachment 15.1, sets out the basis of the allocation of costs between the three HRS. The CAM allocates the HRS building block revenue set out in Chapter 13 to each tariff class on the basis of a number of different cost allocators, which include a combination of asset values, customer numbers and consumption. The allocators selected reflect the best estimate of the cost to AGN of servicing each tariff class.

There has been no material change in cost allocation between the HRS proposed by AGN for the next AA period. Rather, the previous approach to cost allocation that was approved by the AER for the current AA period has been updated for current cost (or building block) information provided throughout this AAI.

15.5 Haulage Reference Service Tariff Classes

Rule 94(1) requires customers for the three HRS to be divided into tariff classes. Customers are assigned to a particular tariff class within a HRS on the basis of their geographic location. The list of tariff classes is shown in Table 15.1.

TABLE 15.1: SOUTH AUSTRALIAN TARIFF CLASSES

Haulage Reference Service	Tariff Class	Tariff	Geographical Zone
Domestic	Tariff R – Residential	Residential (excluding Tanunda)	All (excluding Tanunda)
Domestic	Tariff R – Residential	Residential – Tanunda	Tanunda
Commercial	Tariff C – Commercial	Commercial (excluding Tanunda)	All (excluding Tanunda)
Commercial	Tariff C – Commercial	Commercial – Tanunda	Tanunda
Demand	Tariff D – Northern	Tariff D	Adelaide North
Demand	Tariff D – Central	Tariff D	Adelaide Central
Demand	Tariff D – Southern	Tariff D	Adelaide South
Demand	Tariff D – Peterborough	Tariff D	Peterborough
Demand	Tariff D – Port Pirie	Tariff D	Port Pirie
Demand	Tariff D – Riverland	Tariff D	Riverland
Demand	Tariff D – South East	Tariff D	South East
Demand	Tariff D – Whyalla	Tariff D	Whyalla

15.5.1 Tariff R and Tariff C

The Tariff R – Residential and Tariff C – Commercial tariff classes both comprise two categories based on geographic location. The first category captures all consumers in South Australia, excluding Tanunda (which is in the Barossa Valley). A separate tariff was approved by the AER for the current AA period for customers connected to the newly built network in Tanunda. The Tariff R and Tariff C Reference Tariffs comprise the following charging parameters:

- supply charge (in dollars per day); and
- banded volume charges (in dollars per gigajoule per day).

15.5.1.1 Supply Charge

The supply charge is a fixed daily charge that applies to all DPs and is designed to:

- reflect the predominantly fixed-cost nature of gas distribution; and
- signal to customers their connection costs, having regard for the size, location and type of network user.

15.5.1.2 Banded Volume Charges

Both Tariff R and Tariff C Reference Tariffs consist of a number of volumetric (or consumption) based charging parameters (in dollars per gigajoule per day). Tariff R will comprise the following three volumetric charging bands:

- a charge for the first 0.0274 gigajoules of Gas Delivered (dollars per gigajoule) – equating to 10 gigajoules per annum;
- a charge for the next 0.0219 gigajoules of Gas Delivered (dollars per gigajoule) – equating to the next 8 gigajoules per annum; and
- a charge for Additional Gas Delivered (dollars per gigajoule).

The first step of consumption broadly captures a customer using a gas cooker and solar hot water system, the second step captures a customer with a non-solar gas hot water system while the final step captures customers utilising gas for space heating.

Tariff C will maintain the following four volumetric charging bands:

- a charge for the first 0.9863 gigajoules of Gas Delivered (dollars per gigajoule) – equating to 360 gigajoules per annum;
- a charge for the next 4.274 gigajoules of Gas Delivered (dollars per gigajoule) – equating to the next 1,560 gigajoules per annum;
- a charge for the next 11.178 gigajoules of Gas Delivered (dollars per gigajoule) – equating to the next 4,080 gigajoules per annum; and
- a charge for Additional Gas Delivered (dollars per gigajoule).

Both the Tariff R and Tariff C classes are structured as ‘declining block tariffs’. The declining block structures are intended to reflect the relatively low marginal cost associated with the ongoing supply of natural gas to a DP and are also designed to encourage greater network utilisation, which is part of the package of measures used by AGN to address the observed long-term decline in average customer consumption (see Chapter 14).

15.5.2 Tariff D – Demand

The structure of the demand tariff classes consist of a number of banded Maximum Daily Quantity (MDQ) charging parameters (in dollars per gigajoule of MDQ per day), with the first band effectively representing a fixed charge as a minimum chargeable MDQ applies. Consistent with the volume tariffs, Tariff D Reference Tariffs are structured as ‘declining block tariffs’, whereby the charges decrease as MDQ increases (again, designed to increase network utilisation).

The MDQ charges are capacity based charges, which is intended to reflect the key cost driver in supplying demand customers. The structure provides economic signals to demand customers to have a smooth consumption profile as opposed to a ‘peaky’ profile. A flat profile results in improved network utilisation and therefore lower costs in providing reference services (as the capacity/size of the network required to supply a particular volume will be lower).

The locational aspect of Tariff D reflects the different cost of supplying customers and is designed to encourage demand customers to locate in those parts of the network that will impose the least costs on AGN (and hence customers). This lower cost is then factored into the determination of the Reference Tariffs for existing customers on the network and will, all else equal, result in lower Reference Tariffs for those consumers in subsequent AA periods.

For each of the Tariff D classes in the Adelaide Region (Northern, Central and Southern), it is proposed that the Tariff D structure maintains the following four MDQ bands:

- MDQ of 50 gigajoules or less;
- next 50 gigajoules of MDQ;
- next 900 gigajoules of MDQ; and
- additional gigajoules of MDQ.

For each of the remaining Tariff D classes (i.e. in regional areas), it is proposed that the current tariff structure is changed to be the same as the above. Currently, the regional Tariff D tariff classes consist of five MDQ bands, as detailed in Table 15.2. The effect of the change is to combine Band 3 (400 gigajoules of MDQ) and Band 4 (500 gigajoules of MDQ) into a single band (900 gigajoules of MDQ), such that it matches the structure of the Adelaide metropolitan Tariff D.

The proposed regional Tariff D will avoid unnecessary transaction costs as the same tariff structure will apply across all Tariff D customers (as required by Rule 94(2)(b)). The current and proposed tariff structure is set out in Table 15.2.

TABLE 15.2: REGIONAL TARIFF D TARIFF CLASSES

Band	Current Regional Tariff D Structure	Proposed Tariff D Structure
Band 1	MDQ of 50 gigajoules or less	MDQ of 50 gigajoules or less
Band 2	Next 50 gigajoules	Next 50 gigajoules
Band 3	Next 400 gigajoules	Next 900 gigajoules
Band 4	Next 500 gigajoules	Additional gigajoules of MDQ
Band 5	Additional gigajoules of MDQ	

15.5.3 Ancillary Reference Services

As explained in Chapter 6, AGN has accepted a request from our Retailer Reference Group to expand the ARS to include an additional three services, which services were previously non-reference services. AGN proposes to continue with the structure and rate (in real terms) of its Reference Tariffs for the existing ARS over the next AA period. The three new ARS will also have the same structure and rate (in real terms) as that currently applying (see Table 15.3).

TABLE 15.3: FORECAST TARIFFS FOR ANCILLARY REFERENCE SERVICES

Ancillary Reference Service	Tariff (Real $2014/15)
Special Meter Reading	$9.80
Disconnection	$68.00
Reconnections	$68.00
Meter Gas and Installation Test (new service)	$202.00
Meter Removal (new service)	$68.00
Meter Reinstallation (new service)	$74.00

15.6 Grouping of Reference Tariffs on an Economically Efficient Basis

Rule 94(2)(a) requires that a tariff class must be constituted with regard to the need to group network users for Reference Services together on an economically efficient basis.

AGN has developed its tariff classes in recognition of the need to group together network users on an economically efficient basis. In particular, tariff classes have been developed to ensure that customers with similar characteristics (and therefore cost drivers) are allocated to the same tariff class. The customer characteristics that have been considered are the:

- nature of the HRS provided to a DP (i.e. Residential, Commercial or Demand); and
- the location of the customer on the distribution network.

This grouping of customers is consistent with accepted good industry practice.

15.7 Transaction Costs

Rule (94)(2)(b) requires each tariff class must be constituted with regard to the need to avoid unnecessary transaction costs. AGN considers that its proposed reference tariff structures and associated charging parameters effectively balance AGN's objectives of minimising transaction costs and providing appropriate price signals to network users. This reflects that:

- our proposed tariffs and tariff structures are consistent with industry practice; and that
- our proposed tariffs and tariff structures are the same as that currently applying in South Australia, aside from the minor amendment to the regional Tariff D structure (which itself is designed to lower transaction costs).

In summary, the likely transaction costs associated with AGN's tariffs are likely to be consistent with that across the gas industry given its tariffs structures are consistent with industry practice. AGN also considers transaction costs will be no higher than is currently the case given our proposal to maintain, in most cases, the same tariffs that currently apply.

15.8 Stand Alone and Avoidable Costs

Rule 94(3) requires that for each tariff class, the revenue expected to be recovered should lie on or between:

> " (a) *an upper bound representing the stand alone cost of providing the reference service to customers who belong to that class; and*
>
> (b) *a lower bound representing the avoidable cost of not providing the reference service to those customers."*

AGN has defined the stand-alone costs for each tariff class as the costs of providing a distribution network to supply only that tariff class. These costs represent the upper bound of providing reference services to each tariff class, because the costs are calculated based on the assumption that no other tariff class uses the network, thereby ignoring the economies of scale arising from sharing fixed costs with other tariff classes.

AGN has defined avoidable cost for each tariff class to be the cost that can be avoided by not providing reference services to that tariff class. Put another way, this represents the costs (i.e. the return on capital, depreciation and operating expenditure (opex)) associated with dedicated connection assets such as meters, inlets and services.

AGN's CAM calculates the standalone and avoidable cost for each tariff class and demonstrates that the revenue expected to be recovered from each tariff class lies on or between the stand alone and avoidable cost of providing reference services. The methodology applied in the CAM is the same as that currently used by AGN for its South Australian and Victorian networks, which approaches have been approved by the AER as satisfying rule 94(3).[146]

---

[146] AER 2012, "*Access Arrangement Draft Decision Envestra Ltd [Australian Gas Networks Limited] 2013-17 Part 1*", September 2012, pg. 84.

The stand-alone cost for all tariff classes was determined to be the cost associated with the major transmission and high pressure distribution mains forming the core of the network plus the regulator stations. These assets comprise the large diameter, high pressure pipe used in the networks to service customers.[147] The derivation of stand-alone costs also includes the dedicated connection assets used to supply residential and non-residential customers.

The avoidable cost is defined as the cost that can be avoided by not providing reference services to a particular tariff class. The avoidable cost for each tariff class is defined as the costs (i.e. return on capital, depreciation and operating expenditure) associated with dedicated connection assets, such as services and meters.

Table 15.4 shows the outputs of the CAM regarding stand-alone and avoidable costs, excluding Goods and Services Tax. The table demonstrates that the 2016/17 weighted average revenue for each tariff class lies above the lower bound avoidable cost and below the upper bound stand alone cost. AGN's Reference Tariffs therefore comply with Rule 94(3) of the NGR in all cases.

TABLE 15.4: SOUTH AUSTRALIA AVOIDABLE, EXPECTED AND STAND ALONE COSTS $2014/15

Tariff Class	Avoidable Costs ($ million)	Weighted Average Revenue ($ million)	Stand Alone Costs ($ million)	Complies
Tariff D – Northern	2.23	6.87	28.89	Yes
Tariff D – Central	1.31	4.13	28.89	Yes
Tariff D – Southern	0.61	1.16	28.89	Yes
Tariff D – Peterborough	0.02	0.07	28.89	Yes
Tariff D – Port Pirie	0.08	0.31	28.89	Yes
Tariff D – Riverland	0.02	0.22	28.89	Yes
Tariff D – South East	0.13	0.34	28.89	Yes
Tariff D – Whyalla	0.02	0.03	28.89	Yes
Tariff R – Residential	0.80	162.61	184.29	Yes
Tariff C – Commercial	2.46	28.48	48.17	Yes

15.9 Long-Run Marginal Costs

15.9.1 Definition of Long-Run Marginal Cost

Rule 94(4)(a) requires AGN to take account of the Long-Run Marginal Cost (LRMC) for the Reference Services and for each element of each Reference Service when setting tariffs. For this purpose, AGN defines LRMC as a measure of the change in costs as output increases, when all factors of production are variable. This aligns closely with the LRMC as defined in the National Electricity Rules although AGN notes no such definition exists in the NGR.[148]

15.9.2 AGN's Approach to Calculating LRMC

AGN's approach to calculating the LRMC was developed with regard to the methodologies adopted by AGN for the last South Australian AA review and the more recent Victorian AA review. This methodology applies the Average Incremental Cost (AIC) approach, whereby the present value of the incremental investment (both capital and operating expenditure) associated with increasing capacity in the long term is divided by the present value of the change in incremental demand.

[147] The costs of these assets were based on similar costs determined in the South Australian Independent Pricing and Access Regulator's original decision for the Network in 1999.

[148] AEMC 2015, "*National Electricity Rules – Version 71*", April 2015, pg. 1166.

The AIC approach to calculating the LRMC is set out in Box 15.1.

Box 15.1: Average Incremental Cost Approach to Calculating the LRMC

$$LRMC = \frac{PV\ (growth\ related\ shared\ network\ capex)\ +\ PV\ (growth\ related\ shared\ network\ opex)}{PV\ (incremental\ demand)}$$

where:

- PV refers to the 'present value';
- *growth related shared network capex* is the forecast annual capital expenditure (capex) in shared network assets required to meet additional demand over the nominated forecast period;
- *growth related shared network opex* is the forecast annual opex required to operate and maintain the shared network assets required to meet additional demand over the nominated forecast period; and
- *incremental demand* is the change in gas demand (in gigajoules) for each year over the nominated forecast period.

Using the methodology outlined above, AGN attempted to calculate the LRMC for its distribution networks in South Australia by tariff class. AGN considers that calculating the LRMC by tariff class, rather than on a whole-of-network basis, is consistent with NERA Economic Consulting's view that it is inaccurate to refer to a universal marginal cost.[149] Specifically, the LRMC varies on the basis of factors including customer type, location and gas consumption profiles.

These factors are reflected in AGN's tariff classes, and as a result, AGN has attempted to calculate the LRMC for each of its tariff classes.

15.9.3 Considerations in the Calculation of LRMC

15.9.3.1 Growth Related Expenditure

Consistent with past approaches, only forecast expenditure (both capital and operating expenditure) relating to the forecast growth of the shared network to service additional customer demand is included in AGN's LRMC calculation. This is because the calculation of the LRMC relies on the key assumptions that expenditure on shared network assets is driven by growth in customer demand.

Forecast expenditure associated with connection assets such as meters and services are not included in the LRMC calculation. This is because connection assets are typically dedicated to specific customers and are driven by customer numbers, not demand growth.

15.9.3.2 Forecast Period

The length of the forecast period over which the LRMC is calculated should take into consideration the useful life of shared network assets. However, the forecast period is not typically set to equal the useful life of new network assets (which can be as long as 60 years) because capital expenditure, operating expenditure and demand forecasts cannot be produced for such a long period into the future with any degree of accuracy.

AGN adopted a forecast period of 10 years as it considers that a 10-year forecast period captures long-run costs without drawing on forecasts that are projected too far into the future to be reliable.

---

[149] NERA Economic Consulting 2006, "*Distribution Pricing Rule Framework Network Policy Working Group*", December 2006, pg. 32.

15.9.4 LRMC Calculation Outcomes

AGN was unable to calculate reasonable values for the LRMC at the tariff class level, by geographical region or even at a whole-of-network level for South Australia. The LRMC values calculated were either too large (relative to the actual tariffs within each tariff class) or negative. This is consistent with the LRMC calculation outcomes achieved at the time of the last South Australian and Victorian AA reviews. AGN analysed the data and underlying assumptions which led to these outcomes and identified that:

- forecast capital and operating expenditure cannot be produced down to the tariff class level or by geographical location in South Australia;
  - consequently, AGN needed to pro-rata the expenditure based on a combination of customer numbers and consumption in order to derive expenditure at the tariff class level;
- the forecast growth-related capital expenditure and operating expenditure relates to projects which only affect small segments of the gas distribution network that are experiencing localised growth in customer numbers; and
- gas consumption is not growing steadily in any of the tariff classes in South Australia;
  - in fact, demand growth for South Australian volume customers is declining (i.e. negative growth) over the next 10 years (see Chapter 14).

This means that:

- there is insufficient data at the level of detail required to accurately and meaningfully calculate the LRMC by geographical region and by tariff class; and
- the forecast expenditure and demand data suggests that, at the tariff class level, expenditure on shared network assets is not driven by growth in customer demand.

As a result, it is not possible for AGN to obtain reasonable LRMC outcomes using the AIC approach given the data limitations. Further, AGN is not aware of any other suitable or practical approaches to quantifying the LRMC in light of the issues identified above.

15.9.5 Consideration of LRMC When Developing Tariffs

Rule 94(4)(a) requires that a tariff, and if it consists of two or more charging parameters, each charging parameter for a tariff class, must take into account the LRMC for the Reference Service or, in the case of a charging parameter, for the element of the service to which the charging parameter relates. In addition, AGN must demonstrate how the relevant LRMC has been taken into account in determining a tariff for a tariff class or the charging parameters within a tariff class.

AGN has had regard to the LRMC when determining the Reference Tariffs for each tariff class or the charging parameters within each tariff class. Consistent with the approach currently applied for South Australia and Victoria, AGN has designed its tariffs and tariff parameters to effectively signal the LRMC to network users. In particular, AGN's tariffs are developed with regard to:

- *geographic price signals* – signalling the cost of connecting to a particular geographic zone;
- *declining block structure* – signalling the declining incremental cost of additional gas consumption; and
- *capacity based charges* – signalling the impact of peak demand on capex.

The provision of ARS is an operating expense incurred by AGN. There is no change in the LRMC of providing these services irrespective of the quantity of these services demanded. The tariffs applied for ARS are therefore based on a flat rate as there is no LRMC to signal to customers.

15.10 Response to Price Signals

Rule (94)(4)(b)(ii) of the NGR requires that a tariff, and if it consists of two or more charging parameters, each charging parameter for a tariff class, must be determined having regard to whether customers belonging to the relevant tariff class are able or likely to respond to price signals. AGN has developed its tariffs and the charging parameters that constitute each tariff in such a manner that customers are able or likely to respond to price signals.

The way in which the Tariffs R, C and D, and their associated charging parameters, have been developed is set out below. AGN's proposed Reference Tariffs for 2016/17 are set out in Tables 15.5 through 15.7.

15.10.1 Demand Tariffs

Demand tariffs have been structured so that customers can respond to pricing signals whilst providing certainty to customers on the amount of their annual charge. This is because the demand tariffs are structured as 'declining block tariffs' based only on an agreed MDQ, not the actual consumption of gas consumed on any given day. Consequently, the demand tariff structures motivate customers to manage their actual gas consumption within the constraints of their agreed MDQ. This promotes better capacity utilisation of AGN's network (noting that agreed MDQ will decrease if actual MDQ decreases).

AGN has also ensured the difference in the network charge between demand tariffs and the commercial tariff is as small as possible for a customer consuming 10 terajoules per annum (10 terajoules being the threshold by which a customer is required to shift from a volume-based commercial tariff to a capacity-based demand tariff). These customers currently face an increase to their network charge as they transition to a demand tariff despite not imposing any additional requirements on the Network.

15.10.2 Domestic and Commercial Tariffs

The variable nature of the volume charge for residential and commercial tariffs imply that customers are able to and can respond to price signals, by adjusting their consumption of gas. Furthermore, the residential threshold that defines the step between the first, second and third tariff bands has been set with regard to the spread of appliance penetration across domestic network users in South Australia. Both these measures promote efficient use of the network and assist AGN to address the long-term decline in average consumption.

15.10.3 Ancillary Reference Services

ARS tariffs reflect the operating expense to AGN of providing these services. Each tariff reflects the actual cost to AGN of providing each service and therefore delivers the appropriate price signal.

15.11 Summary

AGN recovers its regulated revenue by charging Reference Tariffs to customers for HRS and ARS. All proposed tariffs have the same structure as that applying over the current AA period, aside from the minor amendment to regional Tariff D structures, and fall between the stand alone and avoidable costs. The tariff structures are efficient, contain no cross subsidy and have taken into account factors such as transaction costs, LRMC and the ability for consumers to respond to price changes. The proposed tariffs to take affect as at 1 July 2016 are detailed in Tables 15.5 through 15.7.

TABLE 15.5: TARIFF R AND C DOMESTIC HAULAGE SERVICE TARIFFS $2016/17

Charges per Network Day (excluding Goods and Services Tax)	
Tariff R (excluding Tanunda)	
Base Charge ($ per day)	$0.3452
Charge for the first 0.0274 gigajoules of gas delivered ($ per gigajoule)	$27.8502
Charge for the next 0.0219 gigajoules of gas delivered ($ per gigajoule)	$13.4437
Charge for additional gas delivered ($ per gigajoule)	$4.5509
Tariff C (excluding Tanunda)	
Base Charge ($ per day)	$0.7267
Charge for the first 0.9863 gigajoules of gas delivered ($ per gigajoule)	$13.8615
Charge for the next 4.2740 gigajoules of gas delivered ($ per gigajoule)	$7.4394
Charge for the next 11.1780 gigajoules of gas delivered ($ per gigajoule)	$3.1883
Charge for additional gas delivered ($ per gigajoule)	$1.7259
Tariff R (Tanunda)	
Base Charge ($ per day)	$0.3452
Charge for the first 0.0274 gigajoules of gas delivered ($ per gigajoule)	$36.2053
Charge for the next 0.0219 gigajoules of gas delivered ($ per gigajoule)	$17.4768
Charge for additional gas delivered ($ per gigajoule)	$5.9162
Tariff C (Tanunda)	
Base Charge ($ per day)	$0.7267
Charge for the first 0.9863 gigajoules of gas delivered ($ per gigajoule)	$18.0200
Charge for the next 4.2740 gigajoules of gas delivered ($ per gigajoule)	$9.6712
Charge for the next 11.1780 gigajoules of gas delivered ($ per gigajoule)	$4.1448
Charge for additional gas delivered ($ per gigajoule)	$2.2437

Notes to Table 15.5:

- *The total daily Charge will comprise the Base Charge plus a Charge for the Quantity of Gas delivered (or estimated to have been delivered) through the Domestic Delivery Point.*
- *The Charge for the Quantity of Gas delivered (or estimated to have been delivered) through the Domestic Delivery Point will be calculated at the rates shown in the table.*
- *A reference in the table to the Gas delivered through the Domestic Delivery Point is a reference to Gas delivered through the Domestic Delivery Point whether for the account of the Network User or for the account of any other person or persons.*
- *Charges will be calculated to the nearest four decimal places.*

TABLE 15.6: TARIFF D DEMAND HAULAGE SERVICE TARIFFS $2016/17

Monthly Charges, Gigajoule MDQ (excluding Goods and Services Tax)					
Adelaide Region	**Northern Zone**		**Central Zone**	**Southern Zone**	
50 gigajoules or less	$2,672.1361		$2,672.1361	$2,672.1361	
Next 50 gigajoules ($ per gigajoule)	$51.9579		$61.7046	$72.7683	
Next 900 gigajoules ($ per gigajoule)	$32.4374		$39.2409	$45.5722	
Additional gigajoules ($ per gigajoule)	$9.8284		$11.2454	$13.7434	
Other Regions	**Port Pirie**	**Riverland**	**South East**	**Peterborough**	**Whyalla**
50 gigajoules or less	$2,672.1361	$3,771.7838	$2,672.1361	$3,771.7838	$2,672.1361
Next 50 gigajoules ($ per gigajoule)	$51.9579	$75.8658	$51.9579	$75.8658	$51.9579
Next 900 gigajoules ($ per gigajoule)	$18.0066	$47.2738	$26.8177	$47.2738	$26.8177
Additional gigajoules ($ per gigajoule)	$9.0472	$9.8284	$9.8284	$9.8284	$9.8284

Notes to Table 15.6:

- *The Demand Haulage Charges shown above are charges for a complete calendar month.*
- *The Charge for a calendar month will accrue from day to day in equal portions.*
- *Charges will will be calculated to the nearest four decimal places..*
- *For the purpose of calculating daily overrun charges pursuant to Clause 5 of the General Terms and Conditions, the overrun rate is $15 per gigajoules (excluding Goods and Services Tax).*

TABLE 15.7: ANCILLARY REFERENCE SERVICES TARIFFS $2016/17

Ancillary Reference Services (excluding Goods and Services Tax)	
Special Meter Read	$10.10
Disconnection Service	$71.00
Reconnection Service	$71.00
Meter Removal	$71.00
Meter Reinstallation	$77.00
Meter Gas and Installation Test	$210.00

Notes to Table 15.7:

- *Where the Reference Tariff for an Ancillary Reference Service (as varied) is less than $20, the Reference Tariff (as varied) will be rounded to the nearest 10 cents (with five cents rounded upwards). Where the Reference Tariff for an Ancillary Reference Service (as varied) is $20 or more, the Reference Tariff (as varied) will be rounded to the nearest dollar (with 50 cents rounded upwards).*

16 Tariff Variation Mechanisms

Page intentionally left blank

16 Tariff Variation Mechanisms

16.1 Introduction

Chapter 15 set out the proposed Reference Tariffs to apply during the next (2016/17 to 2020/21) Access Arrangement (AA) period. This chapter details how these tariffs are to be adjusted over the next AA period, including the annual process for the approval by the Australian Energy Regulator (AER) of the tariffs to apply in a given regulatory year.

16.2 Requirements of the National Gas Rules

Rule 97 of the National Gas Rules (NGR) provides that:

"(1) A reference tariff variation mechanism may provide for variation of a reference tariff:

(a) in accordance with a schedule of fixed tariffs; or

(b) in accordance with a formula set out in the access arrangement; or

(c) as a result of a cost pass through for a defined event (such as a cost pass through for a particular tax); or

(d) by the combined operation of 2 or more of the above.

(2) A formula for variation of a reference tariff may (for example) provide for:

(a) variable caps on the revenue to be derived from a particular combination of reference services; or

(b) tariff basket price control; or

(c) revenue yield price control; or

(d) a combination of all or any of the above.

(3) In deciding whether a particular reference tariff variation mechanism is appropriate to a particular access arrangement, the AER must have regard to:

(a) the need for efficient tariff structures; and

(b) the possible administrative effects of the reference tariff variation mechanism on administrative costs of the AER, the service provider, and users or potential users; and

(c) the regulatory arrangements (if any) applicable to the relevant reference service before the commencement of the proposed reference tariff variation mechanism; and

(d) the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction); and

(e) any other relevant factor.

(4) A reference tariff variation mechanism must give the AER adequate oversight or powers of approval over variation of the reference tariff.

(5) Except as provided by a reference tariff variation mechanism, a reference tariff is not to vary during the course of an access arrangement period."

16.3 Haulage Reference Services

This section details the various tariff control formulae proposed to be included in the tariff variation mechanism that is set out in the Reference Tariff Policy of the AA Document. This section discusses the tariff variation mechanism and tariff variation process for Haulage Reference Services (HRS). Chapter 6 of this Access Arrangement Information (AAI) describes the services provided by AGN on the South Australian natural gas distribution network (the Network), including HRS.

16.3.1 Tariff Variation Mechanism

Consistent with Rule 97(1), Clause 18.1 of the Regulatory Information Notice (RIN) issued by the AER requires AGN to:

> *"Provide an explanation of the proposed reference tariff variation mechanism and the basis for any parameters used in the mechanism".*

AGN proposes to maintain the current annual tariff variation mechanism in the form of a weighted average price cap (WAPC) formula for the next AA period. The WAPC is a form of tariff basket control, and as such, is allowed for under Rule 97(2)(b) of the NGR. A WAPC constrains the overall movement in Reference Tariffs (as opposed to the movement in individual tariffs) within the AA period.

Importantly, a WAPC places a control on the maximum average price that AGN can charge and not the maximum revenue that the business can recover (which is referred to as a revenue cap). As noted in Chapter 2 of this AAI, AGN considers a WAPC (price cap) is appropriate on the basis that this form of regulation places a stronger incentive on business growth (because revenue increases if gas sales increase under a WAPC). This growth incentive is considered important given that gas is a fuel of choice for most applications.

The proposed WAPC formula, which is consistent with the form of control used in the past two AA periods, is shown in Box 16.1. The right hand side of the WAPC formula calculates the weighted average of the notional revenues determined for the current year (year t), and the previous year (year t-1), which revenues are determined by applying the actual quantities of gas delivered two years prior (year t-2) to the:

- tariffs proposed to apply in year t (which is the year where the adjusted tariffs will apply); divided by
- tariffs applied to customers in year t-1 (which refers to the tariffs currently applying).

The weighted average of these notional revenues is constrained by the left hand side of the WAPC formula, which allows tariffs to increase by no more than the Consumer Price Index (CPI) less the X factor (the X factor was determined in Chapter 13 of this AAI).

The proposed tariff control formula is consistent with the formula applied in the current (2011/12 to 2015/16) AA period, other than the updated values of X and the application of the WAPC formula to the overall revenue from all Reference Tariffs. The WAPC currently applies to each tariff class individually. AGN considers the WAPC should apply to the combined revenue received from all tariff classes as this is:

- consistent with how the WAPC is applied to our Victorian and Albury networks (and other gas distribution networks more generally); and
- will enable rebalancing to occur between tariff classes – applying the WAPC to each individual Reference Tariff prevents rebalancing, therefore rendering the rebalancing control redundant (as is currently the case).

The tariff control formula forms part of Schedule 3 of the Reference Tariff Policy of the AA Document.

Box 16.1: Tariff Control Formula

$$(CPI_t)(1-X_t) \geq \frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij} \bullet q_{t-2}^{ij}}{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{t-1}^{ij} \bullet q_{t-2}^{ij}}$$

where:

CPI_t *is calculated as the CPI for the year ending 31 March immediately preceding the start of year t, divided by the CPI for the year ending 31 March immediately preceding the start of year t-1;*

X_t* *is – 0.05 for 2017/18;*

X_t* *is – 0.05 for 2018/19;*

X_t* *is – 0.05 for 2019/20;*

X_t* *is – 0.05 for 2020/21;*

n *is the number of different Reference Tariffs;*

m *is the different components, elements or variables ("components") comprised within a Reference Tariff;*

p_t^{ij} *is the proposed component j of Reference Tariff i in year t;*

p_{t-1}^{ij} *is the prevailing component j of Reference Tariff i in year t-1 ; and*

q_{t-2}^{ij} *is the quantity of component j of Reference Tariff i that was sold in year t-2 (expressed in the units in which that component is expressed (e.g. gigajoule)).*

* *Xt will be updated to reflect the annual update to the trailing average portfolio return on debt consistent with Attachment 10.2 to this AAI.*

16.3.2 Rebalancing Control Mechanism

The proposed rebalancing control formula is also consistent with that used in the current AA period, other than updated values for X (see Box 16.2). The rebalancing control is intended to provide price certainty to customers as it limits the movement in each tariff class to CPI plus X plus 2%. The rebalancing control formula forms part of Schedule 3 of the Reference Tariff Policy of the Access Arrangement.

Box 16.2: Rebalancing Control Formula

The following formula applies separately to each tariff class:

$$(CPI_t)(1-X_t)(1+Y_t) \geq \frac{\sum_{j=1}^{m} p_t^j \bullet q_{t-2}^j}{\sum_{j=1}^{m} p_{t-1}^j \bullet q_{t-2}^j}, i = 1,...n$$

where:

CPI_t *is calculated as the CPI for the year ending 31 March immediately preceding the start of year t, divided by the CPI for the year ending 31 March immediately preceding the start of year t-1;*

X_t* *is – 0.05 for 2017/18;*

X_t* *is – 0.05 for 2018/19;*

X_t* *is – 0.05 for 2019/20;*

X_t* *is – 0.05 for 2020/21;*

Y_t *is 0.02*

n *is the number of different reference tariffs that make up each tariff class;*

m *is the different components, elements or variables ("components") comprised within a reference tariff;*

p_t^j *is the proposed component j of the reference tariff in year t;*

p_{t-1}^j *is the prevailing component j of the reference tariff in year t-1 ; and*

q_{t-2}^j *is the quantity of component j of the reference tariff that was sold in year t-2 (expressed in the units in which that component is expressed (e.g. gigajoules)).*

* *Xt will be updated to reflect the annual update to the trailing average portfolio return on debt consistent with Attachment 10.2 to this AAI.*

16.3.3 Tariff Variation Process

The tariff variation process is detailed in Section 4.6 of the AA Document and is generally consistent with that applying over the current AA period. The only proposed change relates to the date by which AGN must submit its annual tariff variation mechanism proposal to the AER. In summary, AGN will notify the AER in respect of any variations to Reference Tariffs at least 40 business days (in place of the current 50 days) before those tariffs are proposed to come into effect.

The proposed change to the timing of the annual tariff variation proposal better accords with the timing of the release of the March quarter CPI by the Australian Bureau of Statistics (ABS). The current 50 day time limit requires AGN to submit a tariff variation proposal prior to the actual CPI being known. Within two weeks AGN must then submit a revised proposal incorporating the just released actual CPI.

The AER has recognised the inefficiency of this process by allowing extensions to the submission date until after the ABS has released the March quarter CPI (so that only one tariff variation proposal is provided by AGN to the AER). AGN's proposal to the submission date to at least 40 days prior to the tariffs taking effect therefore formalises current practice.

A tariff variation proposal submission date 40 days prior to the Reference Tariffs taking effect will still provide the AER with 20 business days to review and consequently approve or reject the proposed variations to Reference Tariffs. It will also allow market participants 20 business days to prepare for the implementation of the new tariffs. AGN notes that the proposed Reference Tariffs are usually accepted by the AER given the mechanical nature of the process.

AGN believes that this tariff variation process complies with all aspects of Rule 97 as it:

- limits administrative costs to the AER, AGN, retailers and stakeholders more generally;
- considers arrangements that have applied in the past;
- only allows for Reference Tariffs to change once during a regulatory period, aside from any Cost-Pass-Through Events that might arise; and
- provides adequate oversight to the AER over any proposed variations to Reference Tariffs.

The notification to the AER will continue to provide an explanation of how the proposed variations have been calculated. AGN will also continue to publish its Reference Tariffs, including tariff proposals, on its website.

16.4 Ancillary Reference Services

AGN proposes to maintain its Reference Tariffs for Ancillary Reference Services (ARS) over the next AA period. It is also proposed to continue to adjust those tariffs by changes in inflation only.

16.4.1 Ancillary Reference Tariff Variation Mechanism

Subject to the approval of the AER, AGN will vary the Reference Tariffs for Ancillary Reference Services on the basis of the tariff control formula set out in Box 16.3.

Box 16.3: Ancillary Reference Tariff Variation Mechanism

The following formula applies separately to each ancillary reference service:

$$ART_t = ART_{t-1} \times CPI_t$$

where:

ART_t *is the Reference Tariff that will apply to an Ancillary Reference Service in year t;*

ART_{t-1} *is the Reference Tariff that will apply to an Ancillary Reference Service in year t-1; and*

CPI_t *is calculated as the CPI for the year ending 31 March immediately preceding the start of year t, divided by the CPI for the year ending 31 March immediately preceding the start of year t-1.*

16.4.2 Ancillary Tariff Variation Process

The tariff variation mechanism process for ARS is proposed to mirror that used to vary Reference Tariffs for Haulage Reference Services (as explained in Section 16.3.3).

16.5 Cost-Pass-Through Events

16.5.1 General

In accordance with Rule 97(1)(c), AGN has proposed certain Cost-Pass-Through events for the next AA period. In defining Cost-Pass-Through events, AGN has given consideration to events:

- for which it is unreasonable or unable to provide cost forecasts for the purposes of determining the total revenue requirement (whether it be due to the uncertainty of timing/occurrence or magnitude of the event); and
- that are not included in the capital or operating expenditure forecasts, or for which AGN might already be compensated for through the rate of return.

The proposed Cost-Pass-Through Events are generally consistent with those that applied in the current AA period and are defined in Section 4.5 of the AA Document for the next AA period. AGN is, however, proposing to amend one Cost-Pass-Through Event and include two additional Cost-Pass-Through Events that relate to potential improvements in the security of supply to customers and significant extensions of the Network.

For the purpose of any relevant Cost-Pass-Through Event, an event is considered to materially increase or decrease costs where that event has an impact of 1.0% of the smoothed forecast revenue from Reference Tariffs specified in the AER's Final Decision.

16.5.1.1 Significant Safety Event

The current AA allows AGN to recover (subject to a materiality threshold) costs arising from various factors outside of its control. For example, this includes decisions by governments or other authorities that cause AGN to incur costs (or cost savings as was the case with the removal of the carbon tax) and natural disasters such as floods and earthquakes.

The current Natural Disaster Cost-Pass-Through Event is as follows:

> *'Natural Disaster Event' means:*
>
> *Any major fire, flood, earthquake, or other natural disaster beyond the control of AGN (but excluding those events for which external insurance or self insurance has been included within AGN's forecast operating expenditure) that occurs during the forthcoming access arrangement period and materially increases the costs to AGN of providing reference services*.

A shortcoming of the above Cost-Pass-Through Event is that there may be other situations that:

- may not be categorised as a natural disaster;
- are outside the direct control of AGN; and
- can result in an unsafe situation that might require significant action by AGN to remedy.

For example, in 2007, AGN detected in its Adelaide network material quantities of oil that had been injected, possibly over the course of many years, by unknown upstream parties. AGN expended considerable resources in locating and removing this oil, with some large customers suffering damage to plant and equipment due to the contamination.

AGN is cognisant that, due to the hazardous nature of natural gas when released in an uncontrolled manner, all of its operating procedures and processes must, as far as is reasonably practical, eliminate or minimise risks to consumers and the public. However, combinations of circumstances could arise whereby, despite best practice, a significant safety incident or series of incidents could occur. In this instance, AGN would be obliged to take appropriate action, which may involve replacement or assets deemed to be unsafe. Such action would be undertaken in consultation with the Technical Regulator.

In order to reflect the above, AGN considers it appropriate to broaden the Natural Disaster Cost-Pass-Through Event to a Significant Safety Event, as follows:

> *'Significant Safety Event' means:*
>
> *Any flood, earthquake (or other natural disaster) or event, or series of events, that result in any part of the Network being damaged or posing an unacceptable risk to persons (but excluding those events for which external insurance or self insurance has been included within AGN's forecast operating expenditure) that occurs during the forthcoming access arrangement period and materially increases the costs to AGN of providing reference services.*

16.5.1.2 Improving Security of Supply

A significant gas outage occurred in April 2015 where almost 10,000 customers were impacted by the loss of gas supply to the cities of Port Pirie and Whyalla. The outage was a result of a fault on the upstream gas transmission pipeline owned by Epic Energy. Customers were left without gas supply for up to nine days, with significant disruption to residential, industrial and commercial businesses as well as to the local economy more broadly.

This follows a gas outage in May 2012 when a third party damaged a key supply main in the Whyalla network resulting in the loss of supply to 2,800 customers in that region. Another outage occurred in May 2008 as a result of another failure upstream of the AGN network, which left 3,300 Whyalla customers without supply for an extended period of time.

Such incidents highlight the vulnerability of some parts of the Network that rely on a single source of gas supply, which is often the case in regional areas. While severe interruptions to major pipelines are relatively rare, the experience above shows how communities can be impacted, including multiple times within a short period of time.

Furthermore, when major supply pipelines or gas processing facilities do fail, not only are large numbers of consumers impacted, but the repair and recovery time can be lengthy. As an example, the recent Whyalla and Port Pirie outage required six days for repair to Epic Energy's transmission pipeline and a further three days before AGN could reconnect all customers to the Network.

In the most recent incident, AGN utilised Liquefied Natural Gas (LNG) trucked in from Victoria in order to maintain a minimum safe level of gas supply in the Whyalla part of the Network. There is currently no LNG available in South Australia. AGN believes that the construction of a LNG plant in or near Adelaide, together with mobile LNG equipment, will provide a quicker and more effective response in emergency situations. Such options, however, may be capital intensive and require careful consideration together with an assessment of other options.

AGN is also reviewing the Adelaide gas network for areas that may be vulnerable to single supply risk. While most of the metropolitan gas network has multiple supply feeds, the continuing elongation of the Adelaide metropolitan area to the north and south means that sections of the Network are becoming increasingly vulnerable. Outages on these parts of the Network are likely to have significant safety and economic consequences.

Following the most recent outage, AGN has initiated a program of work to identify where actions can be taken on the Network to improve the security of supply. AGN is not in a position to incorporate the security of supply initiatives in its Revised AA Proposal given the time taken to properly scope out those projects that would satisfy the relevant requirements of the NGR. AGN has therefore proposed a Security of Supply Cost-Pass-Through Event, which will allow AGN to:

- conduct the above assessments on a considered basis, as significant engineering and commercial analysis is required, in addition to consultations with the State Government and other relevant stakeholders; and
- if required, submit for the AER's approval a Business Case in accordance with the Cost-Pass-Through provisions.

AGN believes it is in the long-term interests of consumers to investigate and implement prudent and efficient security of supply solutions as soon as the requisite analysis has been completed, which will be facilitated by the proposed Security of Supply Cost-Pass-Through Event. The proposed Security of Supply Cost-Pass-Through Event is as follows:

> *'Security of Supply Event' means:*
>
> *Approval by AGN's Board to proceed with a proposal to undertake expenditure that would enhance the security of gas supply to consumers and which materially increases the costs to AGN of providing reference services.*

16.5.1.3 Significant Extensions

AGN actively seeks to grow the Network, as this is in the long-term interests of consumers. During our stakeholder engagement program (see Chapter 3), stakeholders supported expanding and improving the network where there is a clear benefit to customers, but they wanted assurance that AGN would conduct an appropriate level of research prior to proceeding with any expansion.

Having regard for stakeholder feedback, and consistent with the National Gas Objective (NGO) (which is set out in Chapter 1), AGN is committed to investigating and evaluating opportunities to supply gas to new areas. Significant extensions to the Network, such as to new townships, are not frequent and usually involve long planning periods, up to several years, before coming to fruition.

AGN has recently expanded the supply of natural gas to Tanunda, north of Adelaide, at a cost of approximately $9 million following a significant planning and consultation period. Similarly, AGN is extending the Network to McLaren Vale, south of Adelaide.

Significant extensions, by their nature, will involve substantial capital investment. These extensions may arise during the next AA period, and as such, can not forecast with certainty a significant extension at the time this AA Proposal has been prepared. In this case, the associated expenditure would not be provided for in the expenditure benchmarks which could be an impediment to such projects proceeding.

Accordingly, it is appropriate that, where such projects are not identified or adequately defined at the time of an AA Proposal, this should not inhibit the development or implementation of such projects. It is therefore appropriate that the following Cost-Pass-Through Event be in place to facilitate significant extensions.

> *'Significant Extension Event' means:*
>
> *Approval by AGN's Board to proceed with a proposal to reticulate a new town or area at a material cost to AGN.*

For example, AGN has commenced investigations into the feasibility of reticulating gas in Mount Barker, in the Adelaide Hills. This region has one of the highest population growth rates in Australia. However, the distance from Adelaide (the closest point at which natural gas is available) is such that to date it has been uneconomic to build a pipeline to supply Mount Barker.

AGN is currently investigating non-traditional options for providing natural gas to the region, including the option of LNG. This option is of interest to AGN because the use of LNG for reticulation at Mount Barker would better facilitate the availability of LNG for security of supply purposes for other parts of AGN's Network.

AGN will continue with its investigations, with a view to developing a business case if the significant extension is deemed to satisfy the relevant requirements of the NGR. In that instance, AGN will trigger the above Cost-Pass-Through Event to progress the extension.

16.5.1.4 Other Cost-Pass-Through Events

The remaining proposed Cost-Pass-Through Events are consistent with the current AA Document and explained in this section.

Regulatory Change Event

A Regulatory Change Event means a change in a regulatory obligation or requirement that:

- falls within no other category of Cost-Pass-Through Event; and
- occurs during the course of an access arrangement period; and
- affects the manner in which AGN provides reference services (as the case requires); and that
- materially increases or materially decreases the costs of providing those services.

Service Standard Event

A Service Standard Event means a legislative or administrative act or decision that has the effect of:

- varying, during the course of an access arrangement period, the manner in which AGN is required to provide a reference service; or
- imposing, removing or varying, during the course of an access arrangement period, minimum service standards applicable to prescribed reference services; or
- altering, during the course of an access arrangement period, the nature or scope of the prescribed reference services provided by AGN;

and that materially increases or materially decreases the costs to AGN of providing prescribed reference services.

Tax Change Event

A Tax Change Event occurs if any of the following occurs during the course of an access arrangement period for AGN:

- a change in a relevant tax, in the application or official interpretation of a relevant tax, in the rate of a relevant tax, or in the way a relevant tax is calculated; or
- the removal of a relevant tax; or
- the imposition of a relevant tax;

and in consequence, the costs to AGN of providing prescribed reference services are materially increased or decreased.

Terrorism Event

A Terrorism Event means an act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear) and which materially increases the costs to AGN of providing a reference service.

Network User Failure Event

A Network User Failure Event means the occurrence of an event whereby an existing network user becomes insolvent or is unable to continue to supply gas to its customers, and those customers are transferred to another network user, and which increases the costs of AGN providing reference services. No materiality threshold applies for this event.

Insurer Credit Risk Event

An Insurer Credit Risk Event means an event where the insolvency of the nominated insurers of AGN occurs, as a result of which AGN:

- incurs materially higher or lower costs for insurance premiums than those allowed for in the access arrangement; or
- in respect of a claim for a risk that would have been insured by AGN's insurers, is subject to a materially higher or lower claim limit or a materially higher or lower deductible than would have applied under that policy; or
- incurs additional costs associated with self-funding an insurance claim, which would have otherwise been covered by the insolvent insurer.

Insurance Cap Event

An Insurance Cap Event means an event that would be covered by an insurance policy but for the amount that materially exceeds the policy limit, and as a result AGN must bear the amount of that excess loss. For the purposes of this Cost-Pass-Through Event, the relevant policy limit is the greater of the actual limit from time to time and the limit under AGN's insurance cover at the time of making this access arrangement. This event excludes all costs incurred beyond an insurance cap that are due to AGN's negligence, fault, or lack of care. This also excludes all liability arising from AGN's unlawful conduct, and excludes all liability and damages arising from actions or conduct expected or intended by AGN.

16.6 Summary

AGN proposes similar tariff variation mechanisms in the next AA period to that which has applied in the current AA period. In particular, AGN is proposing:

- the same tariff control formula, but applied across all Reference Tariffs relating to HRS, as opposed to each tariff class individually;
- the same rebalancing control constraint and formula;
- the same administrative processes for the approval of variations to Reference Tariffs, with a minor amendment to the submission date of the tariff variation proposal to reflect current practice;
- the same Cost-Pass-Through events as those approved by the AER for the current AA period with the addition of cost pass throughs related to improving the security of supply and to facilitate significant extensions of the network where this is in the long-term interests of consumers; and
- to broadened the Natural Disaster Event to address any serious safety concern that arises on the network and materially increases the cost to AGN.

The proposed tariff variation mechanism complies with all relevant requirements of the NGR. In particular, Reference Tariffs are to be varied pursuant to Rule 97(1)(b), the formula for varying tariffs is consistent with Rule 97(2)(b) and the process for the approval of reference tariffs complies with Rules 97(3), 97(4) and 97(5).

Page intentionally left blank

Part E
Other

Page intentionally left blank

17 Non-Tariff Components

Page intentionally left blank

17 Non-Tariff Components

17.1 Introduction

This chapter discusses the key policies and terms and conditions governing access to the South Australian gas distribution network (the Network) over the next (2016/17 to 2020/21) Access Arrangement (AA) Period.

A key part of the relationship between Australian Gas Networks Limited (AGN) and Network Users (who are primarily gas retailers) is a contractual agreement between the parties that governs the conditions (or terms) of access to the Network, which is commonly referred to as a 'Haulage Agreement'. The terms and conditions of the Haulage Agreement typically reflect the terms in the Australian Energy Regulator (AER) approved AA for the relevant network, unless otherwise agreed by the parties.

The terms and conditions have been subject to considerable stakeholder consultation through a number of successive AA review processes, and consequently, have been amended over time to take into account submissions received from stakeholders and decisions made by the AER on those submissions. AGN has applied previous AER decisions as a base for setting the terms for the Network going forward. Further to the above, AGN has received feedback on our proposed terms from our Retailer Reference Group.

As noted in Chapter 2, AGN has networks in most Australian states and territories (not just in South Australia). One benefit of national regulation has been to harmonise our terms across all jurisdictions where AGN has networks. This process of standardisation commenced during the last South Australian AA review process, which was the first review undertaken by the AER in respect of the networks that are owned by AGN.

AGN is continuing with the process of standardising its terms across its networks for the next AA period. AGN considers this process promotes greater efficiency (through lower transaction costs) across the industry by eliminating, to the extent possible, differences in the terms that apply between jurisdictions (noting that, like AGN, many retailers operate across more than one jurisdiction). This was indeed a significant driver behind the decision to introduce a national customer regulatory regime for natural gas networks in 2008.

Some adjustments to the current (AER approved) South Australian terms and conditions are, however, necessary to take into account:

- the stakeholder comments and AER decisions made on our Victorian terms and conditions, which decision was made after the South Australian terms were last approved by the AER;
- comments received from our Retailer Reference Group in the period leading up to the submission of our revised AA proposal to the AER;
- changes necessary as a result of the introduction of the National Energy Customer Framework (NECF) in South Australia; and
- minor changes to reflect the change in our name from Envestra to AGN.

This chapter explains the process undertaken in developing our revised terms and the key changes made to the terms that currently apply to the Network.

17.2 Terms and Conditions

17.2.1 General Approach

The general terms and conditions set out in AGN's revised AA proposal (referred to here as the General Terms) are substantially the same as those that are currently in place.

The South Australian General Terms were reviewed by the AER in 2011 at which time they were revised to take account of around 40 changes deemed appropriate by the AER and retailers. The final General Terms were then approved by the AER in June 2011 and have applied to the Network over the current (2011/12 to 2015/16) AA period. AGN notes that there have been no major areas of dispute or disagreement with Network Users over the General Terms that currently apply to the Network.

The differences between the current and proposed General Terms to apply for the next AA period essentially relate to those changes necessary to ensure the AA reflects the NECF, which was introduced on 1 February 2013 in South Australia (see Section 17.2.2). The terms have also been updated to reflect feedback from our Retailer Reference Group (see Section 17.2.4).

AGN is maintaining its approach of using substantially consistent General Terms across all jurisdictions. As discussed further above, this approach is of particular importance for AGN given the national footprint of the networks owned by the business. This approach has the advantage of improving efficiency and lowering transaction cost by:

- streamlining the contracting process with retailers and other Network Users across jurisdictions;
- reducing the legal costs related to entering into a Haulage Agreement and the costs of administering the agreement over the AA period;
- enabling AGN and retailers to develop and utilise consistent internal procedures across multiple jurisdictions;
- streamlining AGN's response to changes in national laws; and
- streamlining regulatory review processes.

AGN (and Network Users) have therefore taken a consistent and national approach to contracting on AGN's networks, taking into consideration that jurisdictional differences will always contribute to some variation. AGN submits that our national approach to developing and implementing the General Terms across our networks best promotes the National Gas Objective (NGO) set out in Section 23 of the National Gas Law (NGL), which states that:

> *"The objective of this Law is 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 of natural gas."*

17.2.2 The NECF Amendments

In 2002, the Council of Australian Governments conducted a review of the national energy market and devised a set of reforms, known as the NECF. The NECF reforms were aimed at harmonising certain jurisdictional arrangements, developing greater efficiency and enhancing consumer protections. The NECF package of reforms requires a greater interface between distributors and customers through formal contractual relationships and has created new/different obligations between distributors and retailers.

The NECF reforms were agreed to by each jurisdiction in the Australian Energy Market Agreement (AEMA) in 2004. The Ministerial Council on Energy (MCE), which was responsible for developing the NECF, enacted the lead legislation in March 2011, with State legislation following thereafter. On 1 February 2013, the NECF-related changes to the National Gas Rules (NGR) commenced operation as a law of South Australia.

A significant number of legislative and regulatory activities were undertaken by jurisdictions, market bodies, regulators, retailers and distributors to facilitate the introduction of the NECF reforms. AGN, along with other distributors, worked closely with the Government and other key stakeholders (particularly retailers) to implement the new framework in an efficient manner.

The development of the National Energy Retail Law, National Energy Retail Rules (NERR) and amendments to the NGR included significant consultation with all relevant stakeholders over a period of more than four years, with stakeholder working groups and the public more generally providing submissions on multiple drafts of policy papers and draft legislation released by the Government.

As the framework is now embedded in new legislation, AGN is bound by the obligations of the NECF. Consequently it has become necessary to amend:

- Chapter 6 (Terms and Conditions) of the AA Document – Section 6.4 (Credit Policy) is now superseded by NECF law requirements;
- General Terms – amendments are predominantly required to take into account the concept of 'shared customers' and the changed billing and credit support arrangements; and
- Chapter 10 (Glossary) of the AA Document – amendments are required to cater for the new terminology that accompanies the NECF law and which terminology is used in the varied General Terms.

The remainder of this chapter explains the above changes.

17.2.2.1 Chapter 6 of the Access Arrangement Document – Changes due to NECF

The NECF only applies to Networks Users that are retailers. The NECF sets out the credit support arrangements that must apply between AGN and a retailer. However, the Credit Policy (Section 6.4) in the current AA Document applies to all Network Users, including retailers. The credit support requirements in Section 6.4 of the AA Document therefore need to be amended so that they do not apply to retailers (otherwise this would impose duplicate obligations that may be different from those under relevant law).

Below is shown the current Credit Policy, marked up (shaded) to show the obligations that will no longer apply to Network Users that are retailers.

> *"6.4 Network User Policy*
>
> *AGN will not be required to provide Network Services to a Network User, or Prospective Network User, who does not meet the requirements of AGN's Credit Policy. The Credit Policy requires that:*
>
> *(a) a Network User must be resident in Australia or have a permanent establishment in Australia;*
>
> *(b) (if the Network User is incorporated or constituted under any law other than the Corporations Act 2001) the Network User must have provided AGN with a legal opinion in form and substance satisfactory to AGN that confirms:*
>
> (i) the due incorporation and good standing of the Network User;
>
> (ii) the legal capacity of the Network User to enter into and perform the Agreement between the Network User and AGN; and
>
> (iii) the due execution of that Agreement and the enforceability of that Agreement against the Network User;
>
> *(c) the Network User must be capable of being sued in its own name in courts established under the laws of South Australia and other States;*
>
> *(d) the Network User must not enjoy any immunity from legal proceedings or legal process (including, but without limitation, any immunity from execution);*
>
> *(e) the Network User must have an acceptable credit rating, or provide AGN with security acceptable to AGN, on terms and conditions acceptable to AGN;*
>
> *(f) the Network User must have the necessary financial capability to discharge its present and future obligations in relation to Network Services; and*

(g) the Network User must not be an externally-administered body corporate or insolvent under administration (as defined in the Corporations Act 2001) or under a similar form of administration under any laws applicable to the Network User in any jurisdiction.

For the purposes of paragraph (e), AGN will from time to time determine what constitutes an acceptable credit rating. Until otherwise determined by AGN, an acceptable credit rating is a rating of BBB or higher for long-term unsecured counterparty obligations of the entity, as rated by Standard & Poors (Australia) Pty Ltd.

Whenever AGN decides to alter the acceptable credit rating, it will notify all Network Users and Prospective Network Users of the acceptable credit rating or ratings as altered. This information will also be included in the Information Package that AGN is required to maintain under the Rules.

For the purposes of paragraph (e), acceptable security will be:

(a) a bank guarantee, given by an Australian bank acceptable to AGN, for an amount of not less than AGN's reasonable estimate of three months average Charges (calculated by reference to a 12 month period); or

(b) a guarantee of the Network User's obligations given by an entity, acceptable to AGN, that has an acceptable credit rating (as defined above)."

AGN has therefore amended Section 6.4 to make clear that those credit support requirements do not apply to retailers. The new Section 6.4 is shown below, with the amended sections again shaded.

“6.4 Network User Policy

AGN will not be required to provide Network Services to a User, or Prospective User, who does not meet the requirements of AGN's Network User Policy. The Network User Policy requires that:

(a) a Network User must be resident in Australia or have a permanent establishment in Australia;

(b) (if the Network User is incorporated or constituted under any law other than the Corporations Act 2001) the Network User must have provided AGN with a legal opinion in form and substance satisfactory to AGN that confirms:

(i) the due incorporation and good standing of the Network User;

(ii) the legal capacity of the Network User to enter into and perform the Agreement between the Network User and AGN; and

(iii) the due execution of that Agreement and the enforceability of that Agreement against the Network User;

(c) the Network User must be capable of being sued in its own name in courts established under the laws of South Australia and other States;

(d) the Network User must not enjoy any immunity from legal proceedings or legal process (including, but without limitation, any immunity from execution);

(e) if the Network User is a retailer, the Network User must have an acceptable credit rating in accordance with the law, or provide security in accordance with the law. If the Network User is not a retailer, the Network User must have an acceptable credit rating or provide AGN with security acceptable to AGN, on terms and conditions acceptable to AGN;

(f) the Network User must have the necessary financial capability to discharge its present and future obligations in relation to Network Services; and

(g) the Network User must not be an externally-administered body corporate or insolvent under administration (as defined in the Corporations Act 2001) or under

a similar form of administration under any laws applicable to the Network User in any jurisdiction.

For the purposes of paragraph (e), where the Network User is not a retailer, AGN will from time to time determine what constitutes an acceptable credit rating. Until otherwise determined by AGN, an acceptable credit rating is a rating of BBB or higher for long-term unsecured counterparty obligations of the entity, as rated by Standard & Poors (Australia) Pty Ltd.

Whenever AGN decides to alter the acceptable credit rating, it will notify all Network Users that are not retailers of the acceptable credit rating or ratings as altered. ~~This information will also be included in the Information Package that AGN is required to maintain under the Rules.~~

For the purposes of paragraph (e), acceptable security will be:

(a) a bank guarantee, given by an Australian bank acceptable to AGN, for an amount of not less than AGN's reasonable estimate of three months average Charges (calculated by reference to a 12 month period); or

(b) a guarantee of the Network User's obligations given by an entity, acceptable to AGN, that has an acceptable credit rating (as defined above)."

It is noted that AGN has deleted reference (in the above section) to an "*Information Package*" as this is no longer a requirement under the Rules, and such information is in any event provided on an 'as required' basis.

NECF Changes to General Terms

AGN is also required to amend the General Terms set out in the AA Document to cater for NECF and to ensure consistency with the NERR and NGL. (Variations are shown in mark-up in Attachment 17.1). They are made simply to ensure that the terms and conditions are consistent with NECF. In summary, the variations provide for:

- the concept of a 'shared customer', which refers to a customer that is shared by a distributor and retailer;
- supply curtailment, disconnection and reconnection obligations consistent with Parts 5 and 6 of the NERR; and
- revised credit support, billing, invoicing obligations consistent with Part 21 of the NGR.

NECF Changes to Access Arrangement Glossary

AGN is proposing a number of minor amendments to the AA glossary that either reflects new terminology consequential to the introduction of NECF or to simply provide for the definition of terms that assist in the interpretation of the AA. Some of these terms are not new but they may not have previously been required to appear in the glossary. In other cases, a slight change in terminology may be required in order to be consistent with NECF terminology.

The new or amended definitions are consistent with those recently approved by the AER for the AGN Victorian and Albury Access Arrangements.

17.2.3 Other Amendments to the General Terms

In addition to changes to account for the introduction of NECF, the following minor changes to the General Terms have been made, prior to consultation with retailers:

- clause 29.1 – deletion of "*… other than clause 27.6*" – this simply corrects an error in the terms and conditions;

- clause 37.5 – updated to reflect the current entity name of Institute of Arbitrators; and
- clause 42.1 – minor changes to the interpretation clause.

The resultant amended General Terms, which are consistent with those approved by the AER for the AGN Victorian and Albury Access Arrangements, are shown in a marked-up version of Annexure G in Attachment 17.1. Those Victorian and Albury AA terms were subject to extensive public consultation as part of the Victorian and Albury AA review processes, with stakeholders making submissions and the AER deciding on appropriate changes to those terms as recently as April 2013.

17.2.4 Consultation on General Terms

As explained in Chapter 3, AGN developed and implemented a dedicated stakeholder engagement program to inform the initiatives described in this Access Arrangement Information (AAI). Key to the design and implementation of our stakeholder engagement program was the establishment of our Retailer Reference Group, which comprises representatives from four retailers that retail natural gas in the South Australian market. The key matters discussed with our Retailer Reference Group were tariff structures, vulnerable customers and terms and conditions.

With regard to the latter, AGN provided to the Retailer Reference Group several drafts of the General Terms and this Chapter 17 for comment, including on:

- 21 November 2014 – AGN circulated the first draft of the General Terms to the Retailer Reference Group for their comment;
- 21 January 2015 – AGN, after considering the feedback received on the earlier draft, issued a further draft of the General Terms to the Retailer Reference Group;
- 4 March 2015 – AGN circulated a further draft of the General Terms and this Chapter 17 to the Retailer Reference Group, again inviting any further comment on any outstanding issues that remained (AGN notes no further comments were received from the Retailer Reference Group).

Attachment 17.2 sets out all of those comments received from the Retailer Reference Group through the above consultation process and the AGN response to those comments. Attachment 17.2 also sets out the specific amendments that were made to the General Terms as a result of the feedback from the Retailer Reference Group. It is clear from the attachment that there have been extensive comments that have been addressed by AGN as part of the process of developing the terms for this AAI.

AGN appreciates the commitment shown by the Retailer Reference Group to actively engage with AGN to develop our revised General Terms. AGN intends to continue to engage with the Retailer Reference Group through the finalisation of the revised South Australian AA and over the course of the next AA period.

17.2.5 Summary of General Terms

This summary of the General Terms is intended to assist Prospective Users to understand the structure and content of the terms of access to the Network:

1. Pursuant to Section 6 of the AA Document, it is a condition that a Prospective Network User enters into an Agreement with AGN for the provision of any Network Service. The term 'Agreement' is defined in the AA Document and means the entering into of a binding contractual arrangement between AGN and a Network User. Prior to entering into an Agreement, a Prospective Network User must satisfy AGN that it:
    - has the necessary financial capacity to meet its obligations to AGN; and
    - where necessary, has adequate arrangements in place to ensure it can keep gas deliveries into and out of the Network in balance.

2. Annexure F of the AA Document allows for the details pertaining to the specific circumstances of the parties entering into the agreement.
3. Annexure G of the AA Document sets out the general terms and conditions that are to apply, as a minimum, to the provision of each Reference Service. It describes terms and conditions that are applicable to both Haulage Reference Services and Ancillary Reference Services (Part IV of the terms and conditions), as well as those terms and conditions that apply specifically to each type of Reference Service (Part II - Haulage Reference Services, and Part III - Ancillary Reference Services).
4. The clauses applying to Haulage Reference Services (Part II) address matters including:
   - procedures for classifying Delivery Points;
   - meter accuracy and reading;
   - minimum gas quality and delivery pressures;
   - possession of gas and responsibility;
   - warranties and title to gas; and
   - supply curtailment.
5. Part III applies only to the Ancillary Reference Services. This part only consists of one clause because the Retail Market Procedures deal extensively with the obligations surrounding these services.
6. Part IV applies both to Haulage Reference Services and Ancillary Reference Services. These clauses address matters including:
   - invoices and payment arrangements;
   - procedures for determining delivered quantities;
   - termination;
   - liability and indemnities;
   - relationship to the Trade Practices Act 1974;
   - Force Majeure;
   - assistance;
   - access to premises;
   - confidentiality;
   - notices;
   - assignment by the Network User;
   - amendment of the Agreement; and
   - other miscellaneous provisions.

The obligations, duties and responsibilities of AGN and any Network User described in the General Terms are in addition to those established in law or by any relevant regulatory instrument. Where the General Terms described in Annexure E of the approved AA Document are amended, the default position is that the General Terms applying to an existing Agreement will also change accordingly, subject to agreement with the User.

However, a Network User and AGN may agree that all or some of the terms and conditions applicable to their Agreement will not change during the term of an Agreement, regardless of any amendments to Annexure E of the AA Document. Both parties are therefore free to agree to arrangements that reflect their preferred risk profile at a point in time.

17.3 Capacity Trading

There has never been any capacity trading on the Network, as it is a distribution system and, unlike with a transmission pipeline, Network Users do not own capacity on the Network. Nevertheless, the opportunity has been taken to simplify and align the wording in this section to that of Rules 105 and 106, which set out access arrangement capacity trading requirements and Delivery Point change requirements respectively.

17.4 Network Extensions

No changes to the network extensions section of the AA Document are proposed.

It is rare for significant extensions of the Network to take place, and where they have occurred (for example in Tanunda and McLaren Vale); these are usually incorporated into AA forecasts, thereby negating the need for AGN to apply to the AER for significant extensions.

17.5 Summary

The terms and conditions are a key part of the relationship between AGN and Network Users. The terms and conditions are the basis that Network Users gain access to the Network and generally form the basis for the contractual agreement entered into between the parties. Our proposed General Terms have gone through considerable consultation with stakeholders over the past five years, including:

- during the last AA review process for the Network (AGN commenced a process of standardising its terms across all of its networks during the last South Australian AA review process);
- during the last Victorian and Albury AA review process;
- as part of the NECF reforms; and
- most recently, with our Retailer Reference Group as part of the process of developing the revised terms and conditions to apply to the Network from 1 July 2016.

AGN considers that the above engagement process has facilitated the development of revised General Terms that comply with the NGL, NGO and NGR.

Page intentionally left blank

Page intentionally left blank

Australian Gas Networks