Dampier Bunbury Pipeline

Five year plan for the Dampier to Bunbury Natural Gas Pipeline

2021-2025 Final Plan

January 2020

Contents

We are Australian Gas Infrastructure Group. We provide natural gas transportation and other pipeline services for customers in Western Australia via the Dampier to Bunbury Natural Gas Pipeline (DBNGP).

Our services play a critical role in the Western Australian economy. Through the DBNGP we transport gas directly to mining, industrial, commercial and power generation customers. We also transport gas to distribution networks in Perth and other towns to provide energy to homes and businesses.

We understand that the safety, reliability and security of the pipeline are important for our customers, and to support economic prosperity in Western Australia.

With this in mind, our future plans are developed by ensuring we listen, understand and respond in the long term interests of our customers and stakeholders.

Foreword from the CEO

I am delighted to present our Final Plan for the Dampier to Bunbury Natural Gas Pipeline (DBNGP) for the five years commencing on 1 January 2021.

The DBNGP is one of the most important pieces of energy infrastructure in Western Australia. It transports natural gas over 1,600km from the state's north-west to Perth and the surrounding regions for use in power generation, minerals processing, industry and for heating our homes.

Our Final Plan sets out our proposals for the five-year Access Arrangement (AA) period commencing on 1 January 2021 (AA5), which builds on our strong performance in the current AA period (2016-2020, or AA4).

During AA4 we have maintained 100% reliability on the DBNGP – in fact we have required no curtailments of capacity for over ten years. We have also maintained our strong safety record, with no recordable injuries over the past 24 months on the DBNGP.

In planning for AA5, and for the first time for the DBNGP, we introduced a formal customer and stakeholder engagement program. Over 18 months we have engaged with customers and other stakeholders to explain our plans and receive their feedback.

In developing our Final Plan, our objective has been to develop a plan that delivers for current and future customers, is underpinned by effective stakeholder engagement, and is capable of being accepted by our customers and stakeholders. We have also sought to deliver a "no surprises" approach to developing our plans.

For AA5, our focus remains on safety and reliability, alongside managing our costs to ensure we remain sustainably cost efficient.

Our Final Plan includes a reduction in revenue of $241 million from $1,914 million for AA4 to $1,673 million for AA5. This is the result of a drop in total expenditure (totex), from $671 million allowed in AA4 to $618 million in AA5, and a reduction in the rate of return, from 5.83% at the end of AA4 to 4.31% at the start of AA5.

"We will deliver at or near 100% reliability for 8% lower costs and 13% lower revenues."

Our Final Plan proposes a price of $1.43 per GJ. This represents a 6% price cut for many of our customers on negotiated prices and a 4% increase compared to the current reference price. This increase to our reference price, despite the reduction in revenue, reflects the reduction in demand for gas transportation services by our customers, which in-turn is largely driven by a shift away from natural gas to renewable sources of energy to generate electricity.

The Final Plan outlines our approach to addressing the transformation already underway in the energy sector – the increasing penetration of renewable electricity as customers large and small seek to reduce their carbon footprint.

Our customers play a fundamental role in the Western Australian economy – a role which puts them at the forefront of the technological transformation underway as a result of renewable electricity. We are also seeing the effects of the transformation directly, as gas flows along the DBNGP vary considerably across the day to offset intermittent renewable electricity supplies.

We recognise the energy market is changing and this is reflected in our Final Plan – a plan which will deliver value for customers in AA5 and beyond.

We believe we have prepared a Final Plan that responds to the feedback received from our customers and stakeholders and, as such, is capable of being accepted.

This Final Plan also reflects our no surprises approach. I encourage customers and stakeholders to participate in the forthcoming Economic Regulation Authority (ERA) consultation process.

Ben Wilson

Chief Executive Officer

Australian Gas Infrastructure Group

2021-2025

Final Plan

Our Final Plan outlines the activities and expenditure we propose to undertake from 2021 to 2025. It builds on our draft plan published in May 2019, and incorporates the feedback we have received from our customers and stakeholders.

13% ↓

$241 million cut in revenue means savings for our customers

8% ↓

Lower total expenditure

Delivering for Western Australia.

Lower revenue, lower costs, maintaining our strong safety, reliability and service performance.

Delivering for customers

100%

reliability of the DBNGP

0

loss of containment of an energy source

>8 out of 10

customer satisfaction

A good employer

close to top quartile employee engagement

>98%

mandatory training compliance

further process safety improvements and a continued focus on achieving zero harm

Sustainably cost efficient

$53m ↓

cut in expenditure

1.5% ↓

finance costs down from 5.83% to 4.31%

supports the long term competitive position of DBNGP

Full Haul reference price of $1.43 per GJ ($2020)

Dampier Bunbury Pipeline

Glossary			
AA	Access Arrangement	LTI	Lost Time Injury
AA4	DBNGP Fourth Access Arrangement (for the period 2016-2020)	LTIFR	Lost Time Injury Frequency Rate (the number of lost time injuries per million hours worked)
AA5	DBNGP Fifth Access Arrangement (for the period 2021-2025)	MLV	Mainline Valve
AER	Australian Energy Regulator	MRP	Market Risk Premium
AGIG	Australian Gas Infrastructure Group	NGL	National Gas Law
ALARP	As low as reasonably practicable	NGR	National Gas Rules
AMP	Asset Management Plan	opex	Operating Expenditure
BEP	Burrup Extension Pipeline	PJ	Petajoule/s
capex	Capital Expenditure	PMM	Project Management Methodology
CRS	Customer Reporting System	PMO	Project Management Office
DBNGP	Dampier to Bunbury Natural Gas Pipeline (used in reference to the pipeline)	PPRC	Project and Procurement Review Committee
DBP	Dampier to Bunbury Pipeline (used in reference to the companies which own and operate the pipeline)	SCADA	Supervisory Control and Data Acquisition
DRP	Debt Risk Premium	SSC	Standard Shipper Contract
EBSS	Efficiency Benefit Sharing Scheme	SUG	System Use Gas
ECI	Electrical Control and Instrumentation	SWIS	South West Interconnected System
ERA	Economic Regulation Authority	TAB	Tax Asset Base
FFO	Funds from operations	TJ	Terajoule/s
GEA	Gas Engine Alternator	TRI	Total Recordable Injury
GJ	Gigajoule/s	TRIFR	Total Recordable Injury Frequency Rate (the number of total recordable injuries per million hours worked)
		WPI	Wage Price Index

1 Plan Highlights

Our Final Plan outlines the activities and investments we propose to undertake for the AA5 period and the resulting price change for our customers.

IN THIS CHAPTER

We have a strong track record of safety, reliability and cost performance in AA4

Our investments in AA5 are designed to ensure we maintain this strong performance

We are proposing a $53 million cut in totex and $241 million lower revenue compared to AA4

Our Final Plan outlines our proposals for the AA5 period and has been informed by a robust customer and stakeholder engagement program.

This section highlights how we have developed our Final Plan, our achievements for AA4 and the key elements of our proposal for AA5.

1.1 Developing this plan

We have engaged directly with our customers and stakeholders over 18 months to guide the development of this plan. Our process involved:

- talking to our customers and stakeholders about how they would like to be engaged and what topics were most important to them;
- holding several meetings with our customers, called Shipper Roundtables, to enable their direct input into all aspects of our plan;
- publishing a Draft Plan in May 2019, providing an additional opportunity to share our plans with our customers and stakeholders and to seek feedback prior to our submission to the ERA; and
- refining our plans in response to the feedback received.

Our open and transparent approach is integral to making sure there are 'no surprises' for our customers and stakeholders and to achieve our objective of developing a plan capable of being accepted.

1.2 Our track record

Over the AA4 period we have met the high expectations of our customers and stakeholders, including meeting key safety and reliability standards set for our business.

Our vision is to continue to deliver quality services that our customers value, be recognised as a good employer and to remain sustainably cost efficient. During the AA4 period we have come a long way to achieving that vision, and we aim to continue our progress during AA5.

Our key achievements during AA4 so far are summarised below.

Delivering for customers

- Strong reliability, with 100% system reliability, 99% compressor station availability and no curtailments.
- Zero tier 1 and tier 2 safety events, which means there have been no incidents of primary loss of containment of an energy source along the DBNGP.
- Completed intelligent pigging (and in line inspections of unpiggable portions) of the entire DBNGP.
- Built standalone communications infrastructure for the southern section of the DBNGP.
- Ensuring continued reliability with investments in: renewal of metering equipment, including installation of remote controls on shutdown valves at nine sites and over pressure protection at 21 sites; upgrades of a further eight odorant facilities to conform with new standards; and replacement of 28 end-of-life flow computers.

A good employer

- Strong safety performance with no recordable injuries for the last 24 months, and a Total Recordable Injury Frequency Rate (TRIFR) of zero for the last 12 months.
- Employee engagement close to the top quartile for our industry.
- In 2019 98.2% of mandatory training was completed – a new KPI not previously measured.
- Minor refurbishments of our offices and depot.
- Began our program to renovate/refurbish original compressor station accommodation (rather than building new accommodation as originally considered).

Sustainably cost efficient

- Totex of $598 million, $73 million below our allowances in AA4.
- Implemented robust and efficient cyber security systems, which we will build on during AA5.

1.3 What we will deliver

Our Final Plan for AA5 builds on our strong performance during AA4. The activities and expenditure we propose to undertake in the next five years are summarised below.

Delivering for customers

- Maintain our strong safety and reliability performance.
- Deliver standalone communications infrastructure for the northern section of the DBNGP to further ensure the reliability and availability of our network.
- Replace 25 obsolete control systems on compressor units and gas engines to continue to meet customers' needs.
- Modernise the customer experience by improving customer IT interfaces.

A good employer

- Maintain strong health and safety performance.
- Top quartile employee engagement.
- Redevelop our Jandakot depot to provide fit-for-purpose office and training spaces, weatherproof warehousing for critical equipment and spares, and improve site ingress/egress.

Sustainably cost efficient

- Deliver a $241 million reduction (down 13%) in the revenue (or total costs) recovered from our customers over AA5 relative to AA4.
- Reduce totex by $53 million (down 8%) compared to allowed totex in AA4, while delivering prudent and efficient asset and risk management.
- Better position the DBNGP to provide services to current and future customers in response to changes occurring in the energy sector, including increasing renewable electricity and the Western Australian Government's commitment to net-zero emissions by 2050.
- Supporting strong incentive arrangements by proposing an opex incentive scheme.
- Investing in our IT systems, data management, digital capabilities and cyber resilience.

Our Final Plan puts in place the measures necessary to minimise our prices by reducing our costs.

Our proposed price of $1.43 per GJ ($ of December 2020) reflects our lower costs while continuing to deliver the safe and reliable service our customers value.

1.5 Our review timeline

Figure 1.1 sets out the AA review timeline. It includes our process to date and an indicative timeline for the ERA's review process.

1.6 Regulatory framework

The National Gas Law (NGL) and National Gas Rules (NGR) provide the framework for the regulation of certain gas pipelines in Australia. This framework is enacted in Western Australia through the *National Gas Access (WA) Act 2009*.

In Western Australia, the Economic Regulation Authority (ERA) is responsible for regulation under the NGL and NGR framework, including the approval of AA proposals and revisions every five years.

The AA proposal, which we call our Final Plan, contains our proposed reference services and the terms and conditions under which a customer can gain access to the DBNGP.

This includes:

- the services offered on the pipeline;
- the price paid for those services; and
- the non-price terms under which access will be provided.

The terms and conditions approved through an AA set a framework around which pipeline operators like DBP and customers can negotiate access. We may work with our customers to reach agreements that provide more tailored access and services on the pipeline beyond the reference services.

More information on the regulatory framework is included in Attachment 1.1, including a table cross-referencing relevant provisions from the NGR with the relevant sections of our Final Plan, attachments and Access Arrangement document. A document map for the entire Final Plan is at Attachment 1.3.

1.7 Our review objectives

Our aim is to develop a plan that:

✓ delivers for current and future customers;

✓ is underpinned by effective stakeholder engagement; and

✓ is capable of being accepted by our customers and stakeholders.

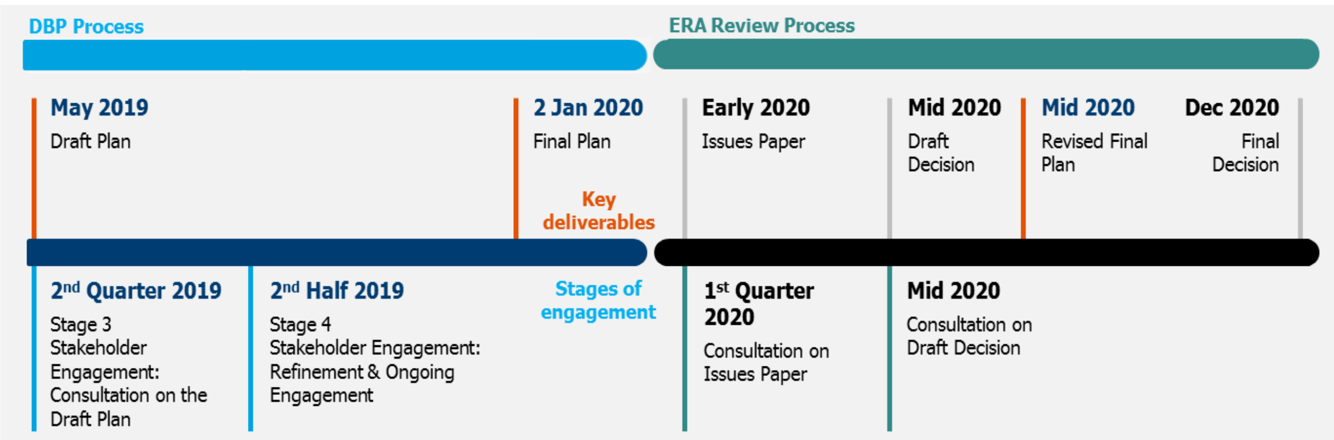
This Final Plan sets out our plans for the DBNGP for the five-year period commencing 1 January 2021 (AA5). The Final Plan presents the proposed revisions for the DBNGP AA, which we are required to submit to the ERA by 2 January 2020. This is in accordance with the review submission date in the current DBNGP AA in respect of the current five-year period (AA4).

The Final Plan follows publication of our Draft Plan in May 2019, the preparation of which included for the first time a robust stakeholder engagement program. The Draft Plan provided an opportunity to engage with our customers and stakeholders prior to developing this Final Plan, which forms our submission to the ERA.

As part of our no surprises approach to running our business, our stakeholder engagement program has enabled our customers and other stakeholders to inform and shape the Final Plan. An important aspect of this has been a series of nine Shipper Roundtables. At least 85% of our customers were represented at the Roundtables, with customers welcoming the process and our commitment to added transparency.

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

Figure 1.1: AA5 Indicative Timeframe



This Final Plan provides the activities and expenditure we propose to undertake during AA5, incorporating feedback received on the Draft Plan and through stakeholder engagement. We also provide an indication of the likely change in prices for our customers (noting prices will be updated to reflect the most recent information available before 1 January 2021).

1.8 How to read this plan

The first six chapters of this document provide an overview of our plans, our business, our stakeholders, our pipeline services and the process we have undertaken to develop a plan that meets our vision, our review objectives and the requirements of the NGL and NGR.

Thereafter, each chapter steps through the regulatory building blocks that form our required revenue and prices. These are:

- *Operating expenditure* (opex) – the expenditure we require to run our business day-to-day (Chapter 7);
- *Capital expenditure* (capex) – the investment in our assets required to deliver services to our customers (Chapter 8);
- *Capital base* – the total value of our investment in the DBNGP, which we have not yet recovered from customers and therefore need to finance (Chapter 9);
- *Financing costs* – the cost of financing our capital base and meeting our tax obligations (Chapter 10);
- *Demand forecasts* – the total amount of services we forecast our customers will demand over the period (Chapter 11); and
- *Incentive arrangements* – additional rewards and penalties that we consider should be applied to strengthen our efficiency and performance, while promoting the long-term interests of our customers (Chapter 12).

In the last two chapters, we outline how we have calculated the total revenue required, the resulting prices for our services (Chapter 13), and the terms and conditions for access (Chapter 14).

This document should be read in conjunction with the attachments highlighted throughout, which together form the Access Arrangement Information required by rule 42.

Attachment 1.3 - the *Final Plan Document Map* – provides an overview of the Chapters of the Final Plan, attachments and Access Arrangement document.

All numbers quoted throughout this Final Plan are dollars of December 2020, unless otherwise labelled.

1.9 Next steps

After receipt of this Final Plan, the ERA will commence a formal engagement process. Customers and other stakeholders are encouraged to participate in this process.

We also welcome any feedback, which can be provided:

💻 online at gasmatters.agig.com.au/

🖃 by mail

💬 in person

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

2 Our business

IN THIS CHAPTER

We are one of Australia's largest gas infrastructure businesses

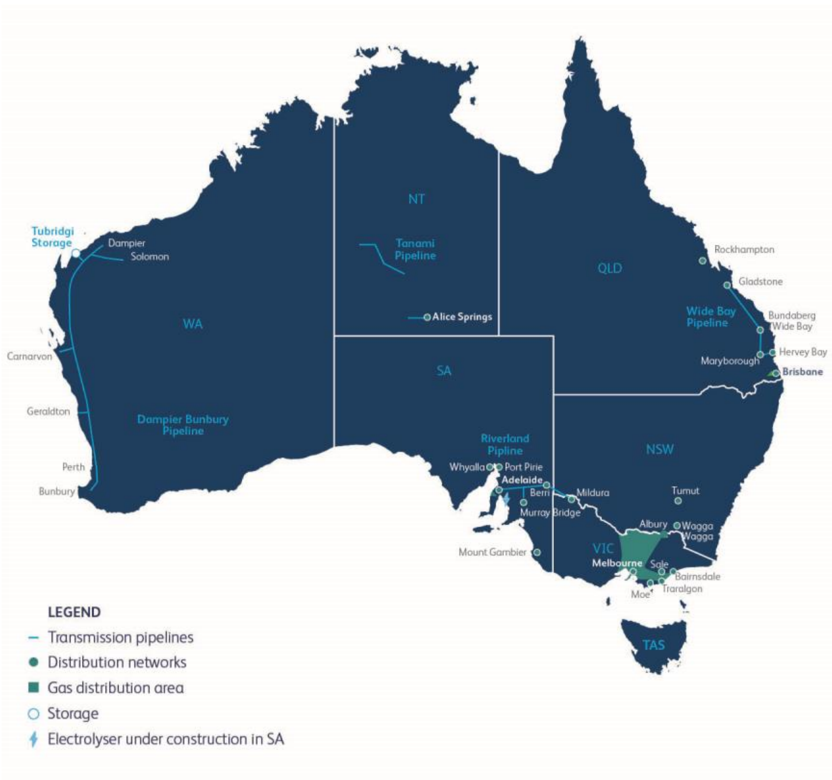
Our vision and values drive what we do and the way we do it

The way customers have used the DBNGP has changed over time and will continue to change as part of a low carbon future

Natural gas provides over half of Western Australia's energy needs, and the DBNGP is the cornerstone of the state's gas sector delivering energy for industry, power generation, homes and export.

DBP, the owner and operator of the DBNGP, is part of the Australian Gas Infrastructure Group (AGIG), one of the largest gas infrastructure businesses in Australia.

Figure 2.1: AGIG assets and operations



2.1 About AGIG

AGIG serves over two million customers across every mainland state and the Northern Territory. Our assets include around 34,000km of distribution networks, over 4,000km of transmission pipelines and 57 petajoules of storage capacity.

In Western Australia, we own and operate assets that deliver and store natural gas. This includes the DBNGP, which transports natural gas from production facilities in the state's north-west to industries, businesses and customers all along the west coast.

In 2017 Australian Gas Networks (AGN), Multinet Gas Networks (MGN) and DBP came together to create AGIG. The scale and expertise of AGIG is delivering enhanced benefits to DBP's customers as outlined in Chapter 3 below. These benefits will be further enhanced as we implement our Final Plan.

2.2 Our vision

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

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

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

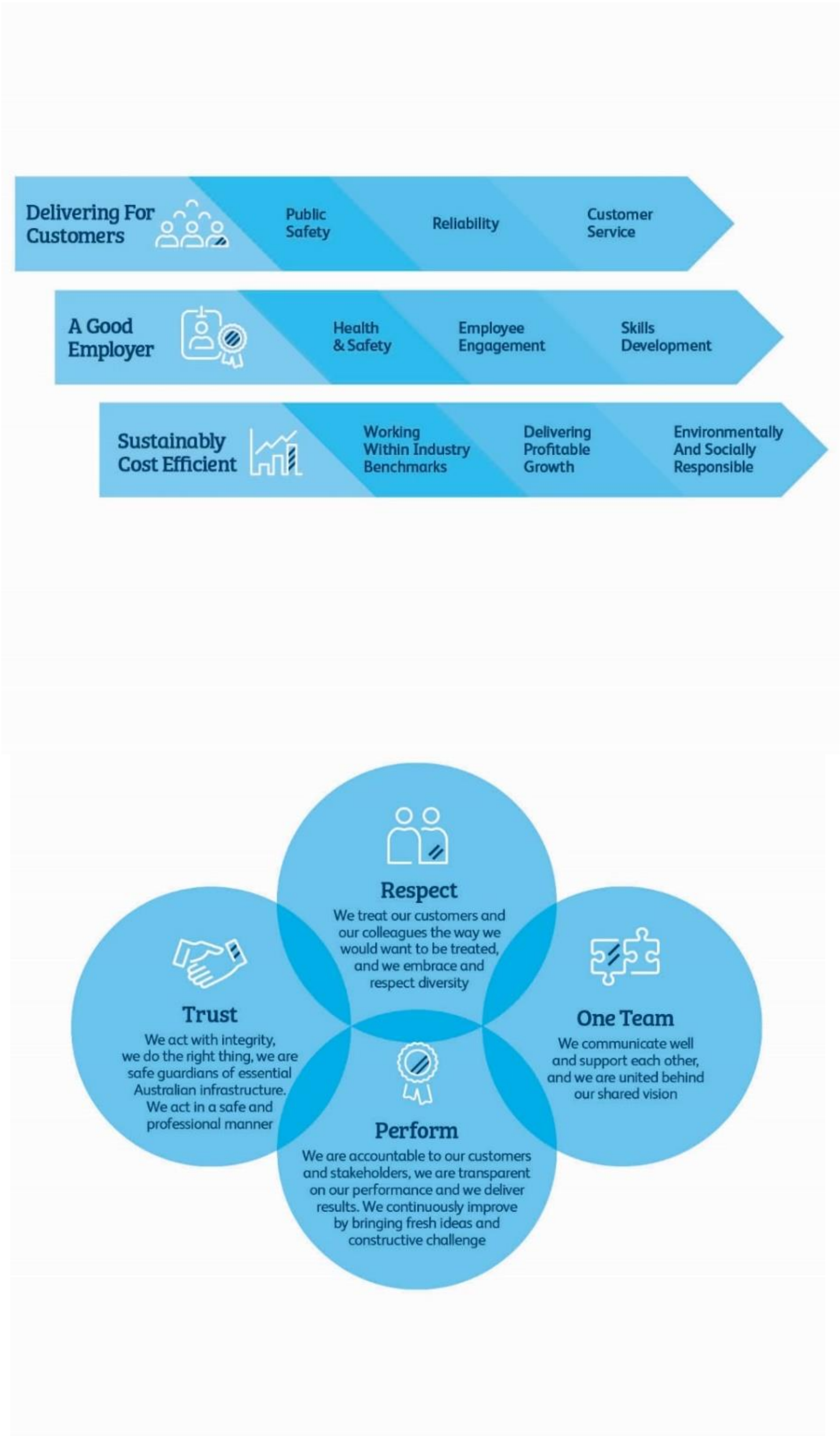
The activities and investments in this Final Plan are designed to achieve these objectives. The chapters that follow will discuss our plans in the context of these objectives alongside the requirements of the NGL and NGR.

We also publicly report under our Vision, most recently in our 2018 Annual Review (Attachment 2.1).

2.3 Our values

Our values of respect, trust, perform and one team drive our culture, how we behave and how we make decisions. As the owner and operator of critical infrastructure providing

Figure 2.2: Our Vision and Values



essential services to Australians, we must ensure we act with integrity and do the right thing for current and future generations.

2.4 Putting customers at the centre of our business

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

Furthering our commitment to put customers at the centre of our business, we are proud to be a founding member of the Energy Charter – giving extra visibility and accountability to this commitment.[1]

This commitment has also been embedded, for the first time, in our Final Plan for the DBNGP. In developing this Final Plan, we have engaged with our customers through nine Shipper Roundtable meetings over 15 months. This engagement process has enabled customers and other stakeholders to inform and shape our proposals. The outcomes of this process are explained throughout this document, while the stakeholder engagement program is detailed in Chapter 5.

Early in our engagement program, we worked with our shippers to develop customer experience aspirations. These are listed in Figure 2.3, and will continue to be an important part of the customer experience we provide.

Figure 2.3: Our customer aspirations

[1] See https://www.agig.com.au/the-energy-charter

2.5 Zero Harm

Maintaining the safety of our workforce and the public is always front and centre in all our activities. When developing our Final Plan and the work programs that underpin it, our aim is to do everything we can to meet the obligations of our safety case and asset management strategies.

We are continually striving to achieve Zero Harm and have comprehensive health and safety policies, procedures and training that support the delivery of this ambition.

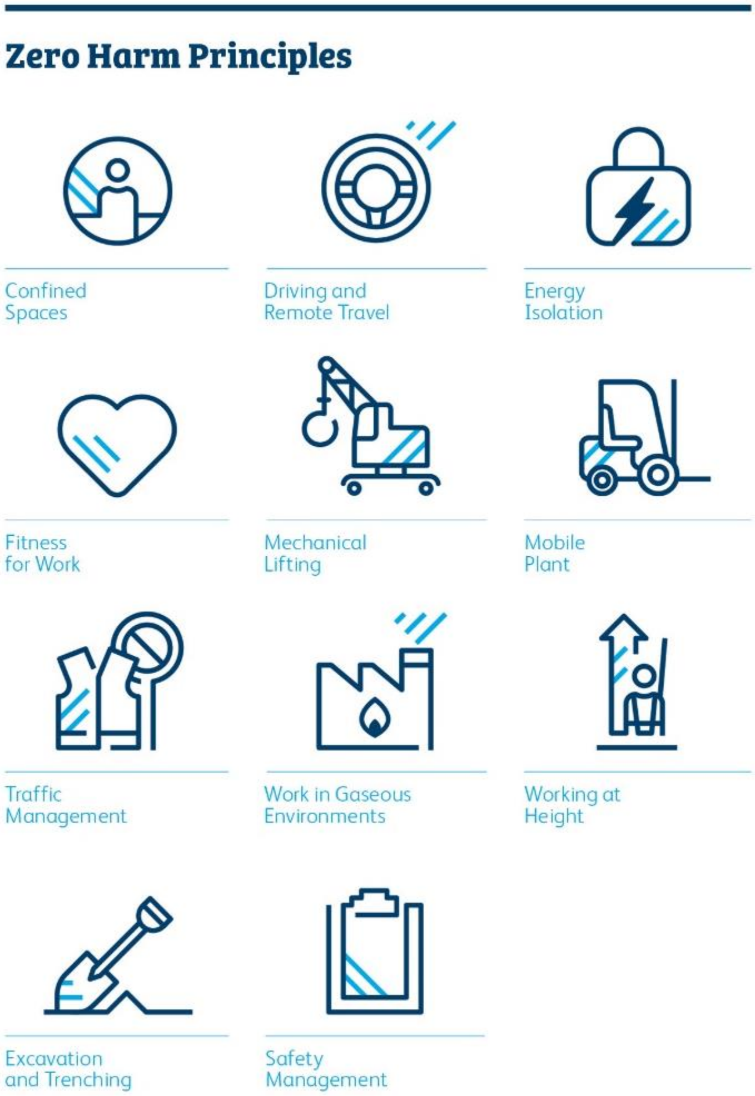
Our Zero Harm Principles (shown in Figure 2.4) highlight areas of risk in our operations where we have non-negotiable rules for our staff and contractors to follow. These are essential to keep our workforce and the public safe. They also help us create a strong safety culture where every employee is personally committed to managing health and safety.

2.6 The gas supply chain

AGIG owns and operates gas infrastructure, including transmission pipelines, distribution networks and gas storage facilities across Australia. Our assets play an important role in the safe and reliable supply of gas to customers at various parts of the gas supply chain. Key components of the gas supply chain are illustrated in Figure 2.5 and include upstream production and processing, transmission, distribution, storage and downstream consumption.

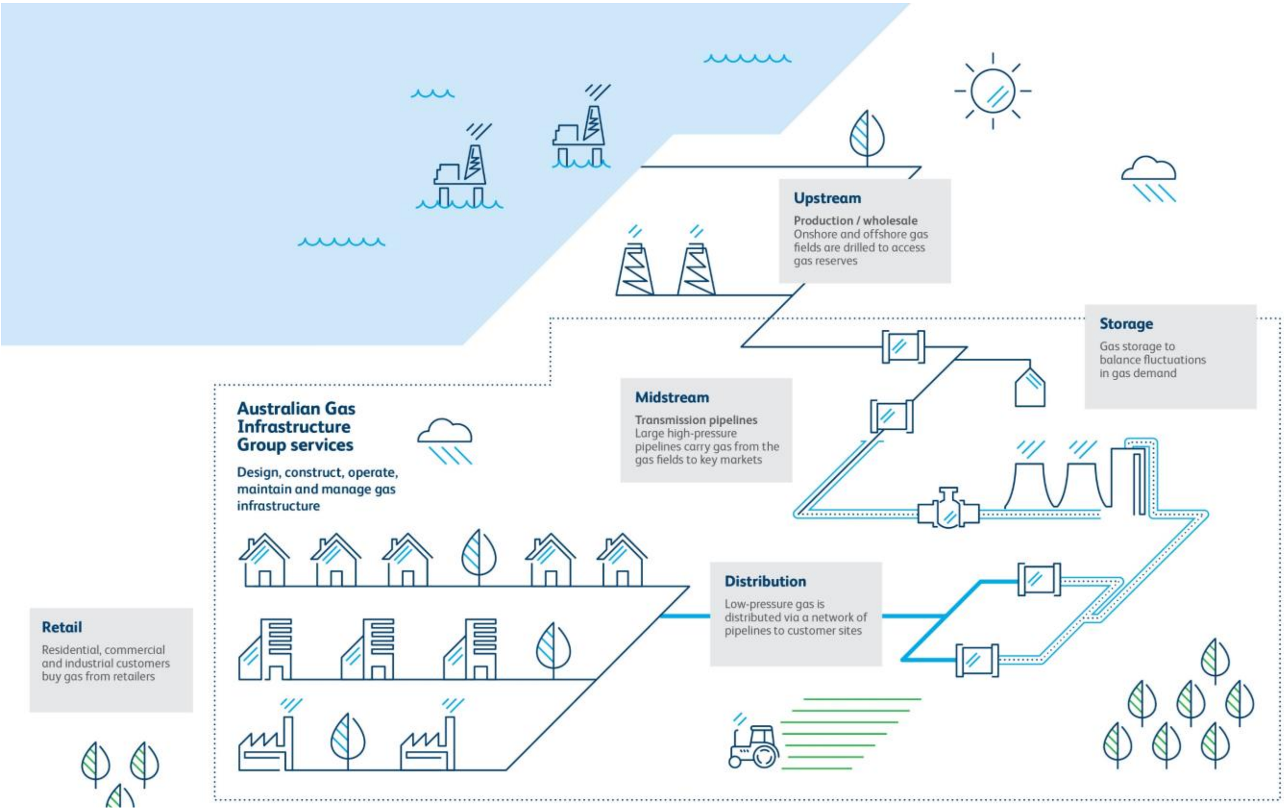
The DBNGP is in the "mid-stream" part of the natural gas supply chain.

Figure 2.4: Our Zero Harm Principles



The DBNGP transmission pipeline carries gas for our customers (shippers) from production facilities in the north-west of Western Australia to the major load centres in the south of the state and around Perth. Over 90% of gas transported through the DBNGP is delivered to large customers connected to the pipeline. The remainder is delivered to Perth's gas distribution network owned by ATCO Gas Australia, who in turn delivers the gas to homes and business. Their customers are billed by a retailer of their choice. For small businesses and householders in Perth, only 3% of the total retail gas bill is a result of our transmission costs.

Figure 2.5: The gas supply chain



2.7 Our role in Western Australia

Western Australia is one of the most gas dependent states in Australia. Natural gas contributes 53% of primary energy usage. Gas also fuels approximately 59% of electricity generated in the state,[2] and 41% in the SWIS,[3] Western Australia's primary power system.

Our customers receive gas transportation and other services on the DBNGP – we transport large quantities of gas safely and reliably every day.

The DBNGP transports the vast majority of Western Australia's gas and is therefore critical to the state's economy.

One of the largest capacity natural gas pipelines in Australia, the pipeline stretches almost 1,600km, linking the gas fields located in the state's north-west directly to mining, industrial, commercial, and ultimately via distribution networks (not owned by AGIG), to residential customers in Perth.

Figure 2.6: The Dampier to Bunbury Natural Gas Pipeline

[2] Department of the Environment and Energy, *Australian Energy Statistics 2017-18*, Table O Electricity Generation by Fuel Type
[3] AEMO, *Wholesale Electricity Market Fact Sheet*, 2017 data.

2.8 About the DBNGP

Since 1985, the DBNGP has transported large quantities of gas safely and reliably to provide energy for industry, power generation, homes and businesses in Western Australia. Figure 2.8 shows the gas transported by industry in 2018.

We deliver leading operational performance with 100% system reliability and 99% compressor station availability in 2018, and no curtailments over the past ten years.

Figure 2.7 outlines the development of the DBNGP since its construction in 1984. From 2006 to 2010 the pipeline underwent significant expansion. Since 2011 several new sources of supply have come online and energy markets have begun a significant transition. Over AA5 we will see further changes in demand for natural gas, and the way the DBNGP is used, as more wind and solar generation enters the electricity market, becoming a viable and commercial competitor to natural gas supply.

Figure 2.8: Industries receiving gas via the DBNGP in 2018 (total 370PJ)

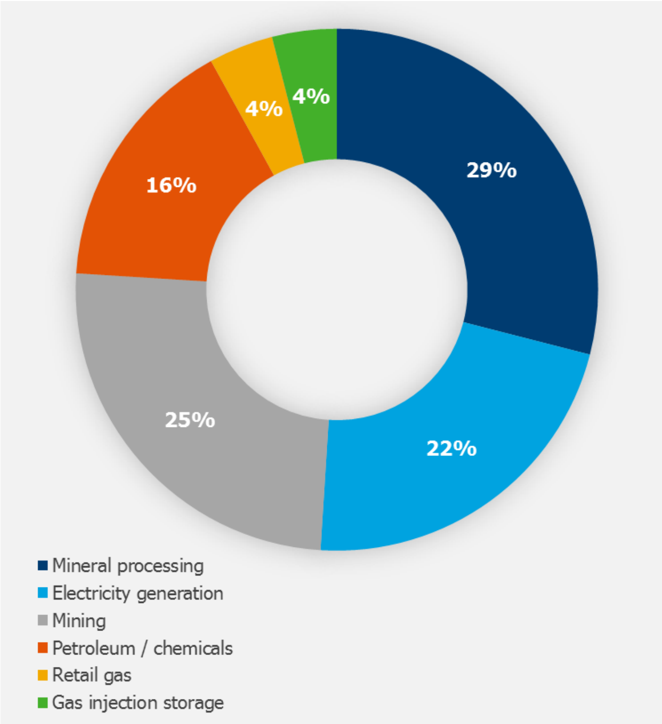
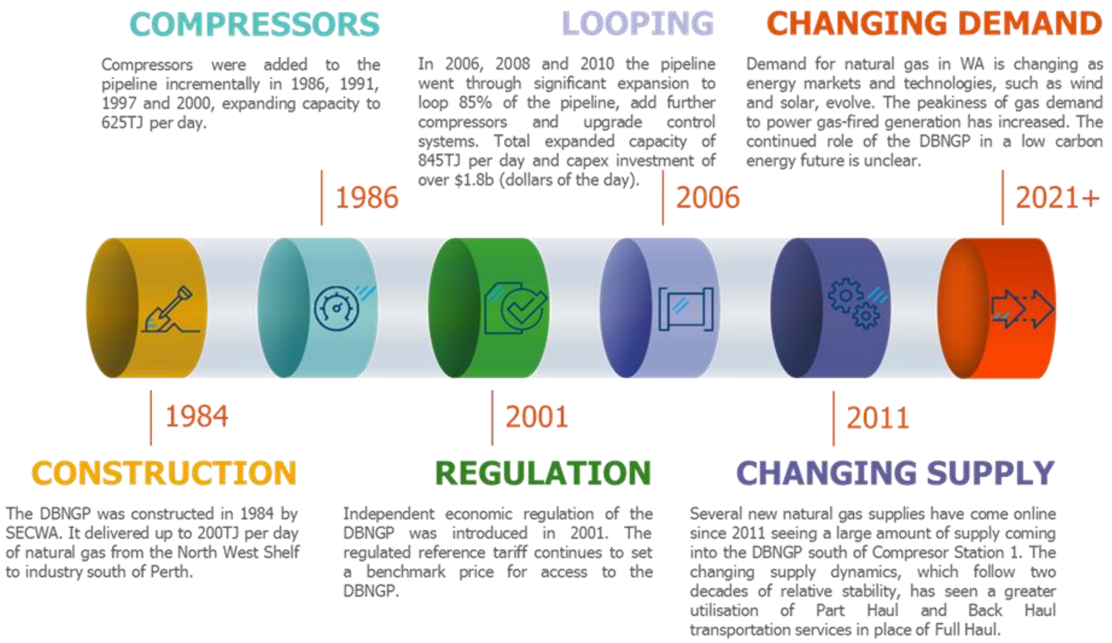


Figure 2.7: History of the DBNGP



2.9 Gas in a rapidly changing energy sector

Long-lived assets like the DBNGP are not immune from change in the energy sector and the wider economy. In recent years, and particularly since the ERA's approval of AA4, the energy sector has undergone a period of rapid change, which is only expected to accelerate during AA5 and beyond.

The rapid progress in renewable power and green hydrogen technology is already changing demand for natural gas and the ways in which energy is generated, transported and used. This effect is over and above that of policy frameworks to reduce carbon emissions.

This has significant implications for the DBNGP, which is currently assumed to have an indefinite life. This is despite Western Australia's policy target to achieve net zero emissions by 2050 and various forecasts that suggest renewable energy will be cheaper than gas by then or sooner. Peaks and troughs in renewable electricity supplies are already affecting the way we operate the pipeline with a growing divergence between nominations and actual use of our services.

Meanwhile in the medium to long term, competition from alternative energy sources, including renewable electricity but also green hydrogen production, is likely to change the nature of regulatory pricing constraints. These issues are discussed in more detail in Chapter 9 Capital Base, where we elaborate on our plans to address these issues in accordance with the NGR.

2.10 Summary

The DBNGP is part of AGIG, one of Australia's largest gas infrastructure businesses. The DBNGP is one of the most important pieces of energy infrastructure in Western Australia, however the role and operation of the DBNGP in transporting natural gas long distances is changing as the energy sector itself changes.

3 Our track record

During AA4 (2016-2020) we maintained our strong safety and reliability record while lowering totex compared to the approved forecasts.

IN THIS CHAPTER

Safety – strong public and workforce safety performance, with a continued focus on our Zero Harm Principles

Reliability – 100% system reliability and no curtailments

Efficiency – below forecast totex

Throughout AA4 we have been working towards achieving our vision.

We have reduced our opex, invested in our pipeline in a prudent manner and maintained our strong safety and reliability performance.

Our activities throughout AA4 have been guided by our key objectives of delivering for customers, being a good employer and remaining sustainably cost efficient. Figure 3.1 below summarises our performance in AA4 to date against our vision.

Figure 3.1: Our performance against our vision in AA4 (2016 to date, with forecast performance to the end of the period)

Vision	Which means	Our performance 2016 to date
Delivering for customers	• Public safety • Reliability • Customer service	• We have had no primary losses of containment and have introduced a new index for maintaining process safety • We have maintained system reliability at 100 % and no curtailments of supply to our customers • For the first time we have completed a robust customer engagement program to inform our Final Plan to the ERA, including a series of nine Shipper Roundtables • We conducted our second annual customer survey and achieved a score of 8.4
A good employer	• Health & Safety • Employee engagement • Skills development	• Our Total Recordable Injury Frequency Rate (TRIFR) was zero throughout 2019 to date, and we have had no recordable injuries for 24 months • We undertook our first employee engagement survey in 2017 with a score of 65 % and improved our score to 67 % in 2019, which sits close to the top quartile of industry performance
Sustainably cost efficient	• Working within industry benchmarks • Delivering profitable growth • Environmentally and socially responsible	• We forecast totex (opex and capex combined) of $598 million which is $73 million below the approved forecasts • We have remained within our established emissions benchmark (the safeguard mechanism) • We had zero reportable environmental incidents

3.1 Delivering for customers

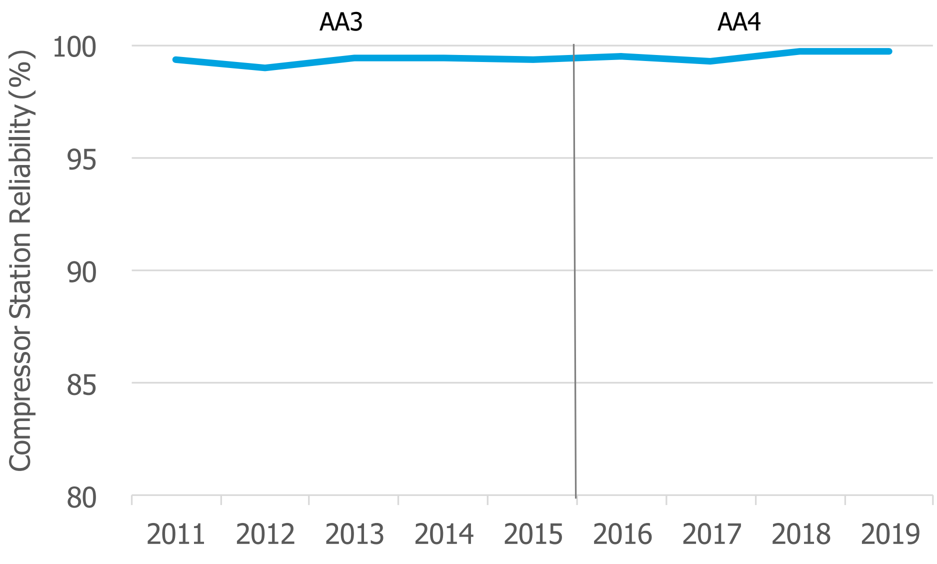
During the AA4 period we have maintained the strong safety, reliability and service performance our customers value. To date, we have:

- maintained public safety with zero incidents of primary loss of containment of an energy source;
- achieved near 100% system reliability throughout the period (Figure 3.2);
- achieved a score of 8.4 in our second annual customer satisfaction survey; and
- invested $92 million in capex projects (forecast by the end of the period) to maintain services.

Our investments to maintain our services to customers have included:

- building standalone communications infrastructure for the southern section of the pipeline;
- intelligent pigging (and alternative inspections for unpiggable portions) of the entire length of the DBNGP; and
- renewals of metering equipment including the installation of remote controls on shutdown valves at nine sites, over pressure protection at 21 sites, upgrades of a further eight odorant facilities to conform with new standards and the replacement of 28 end-of-life flow computers.

Figure 3.2: DBNGP average reliability of all ten compressor stations 2011 to Nov 2019



3.2 A good employer

During the AA4 period we have continued to be a good employer. To date we have:

- maintained our strong safety performance with a total recordable injury frequency rate (TRIFR) of zero at the end of 2019 which has been maintained for 12 months, and no recordable injuries for 24 months (Figure 3.3);
- employee engagement in our 2019 survey was close to the top quartile for our industry with a score of 67%; and
- invested $21 million in capex projects (forecast by the end of the period) to help improve employee health and safety.

Our investments to be a good employer have included:

- upgrades to ladders, platforms, fall protection, gates and railing to improve the safety of employees and contractors working at heights;
- commencing refurbishment of our compressor station accommodation for our remote field staff; and
- minor refurbishments of our Jandakot depot.

New index for process safety

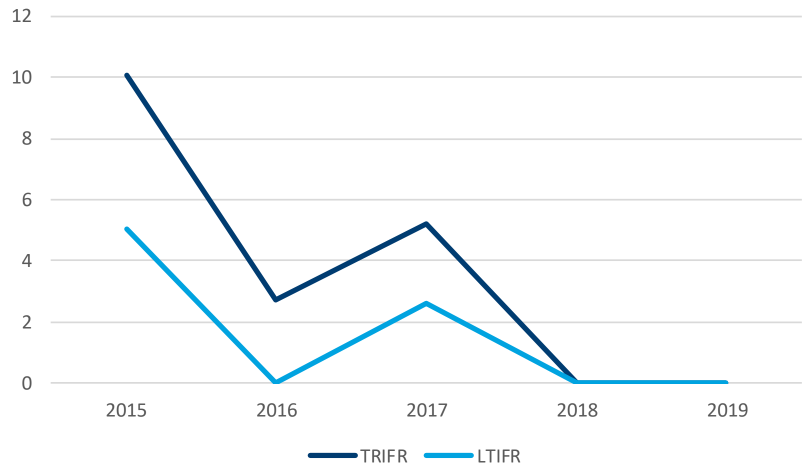
During AA4 we have introduced a new index for monitoring process safety.

In the first stage the index has tracked tier 1 and tier 2 safety events. These are events which include a primary loss of containment of an energy source. We have had no tier 1 or tier 2 events.

In 2019, as part of a second stage, we began tracking tier 3 and tier 4 events. These are leading indicators that help to pre-empt any tier 1 and 2 events, enabling action to prevent more serious incidents.

This new index further improves our ability to maintain public safety and the safety of our workforce.

Figure 3.3: DBNGP safety performance



3.3 Sustainably cost efficient

We have focussed on being sustainably cost efficient. By the end of the AA4 period we forecast we will have:

- incurred $350 million in opex (excluding SUG) which is in line with our allowance and includes ongoing annual savings of around $7 million reflecting changes in our business structure as a result of coming together as AGIG in 2017 (Figure 3.4);
- incurred an estimated $83 million in SUG expense, lower than our allowances, as a result of moderating gas prices during AA4 (Figure 3.5); and
- invested $123 million of stay-in-business capex, which is $14 million above our allowance in AA4, partly offset by lower expansion capex which is $4 million below our allowance (Figure 3.6).

We have invested prudently to ensure the integrity of our assets. Specifically, we have:

- invested in cyber security to protect our systems against the increasing threat levels and built a strong cyber security culture to ensure we remain resilient; and
- extended, improved, replaced and retired assets in line with our asset management plans and Safety Case (Attachments 8.1, 8.2 and 8.3).

3.4 Summary

During AA4 we have maintained our strong safety and reliability record, while lowering costs since becoming part of AGIG.

Figure 3.4: Total opex in AA4

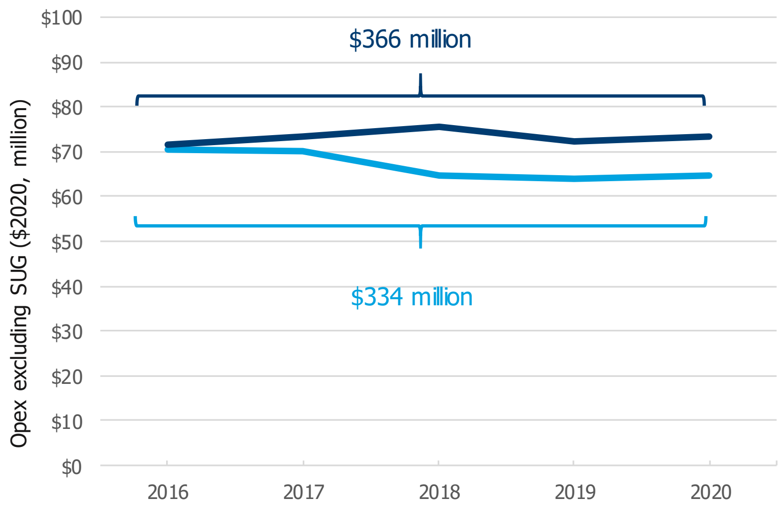


Figure 3.5: SUG in AA4

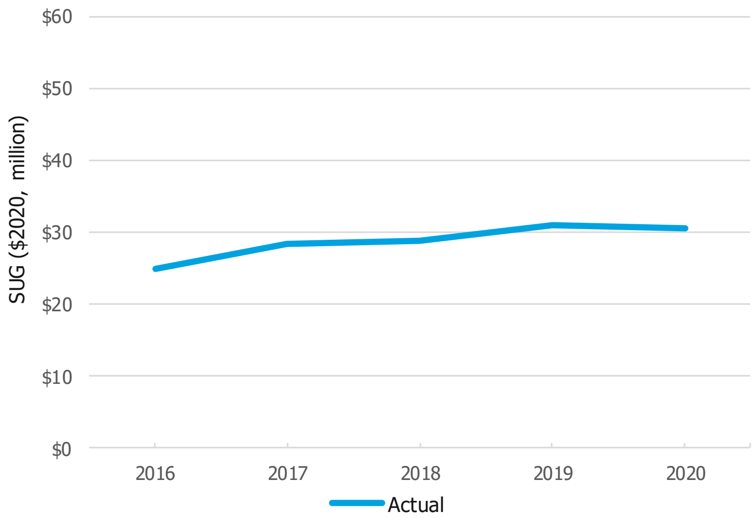
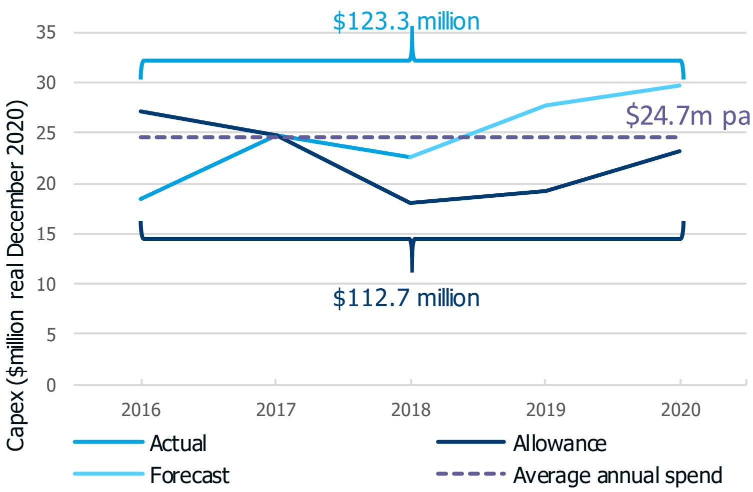


Figure 3.6: Total capex in AA4



4 What we will deliver

IN THIS CHAPTER

We will continue to deliver services that customers value

We will maintain our strong safety and reliability performance, while incurring less totex than in AA4

We will recover $241 million (13%) less revenue than in AA4

We will continue to deliver a safe and reliable natural gas supply for Western Australia. We will be a good employer and seek opportunities to remain cost efficient and to play an important role in a low carbon economy.

During AA5 our investments and activities will continue to be guided by our vision and the objectives that underpin that vision.

Figure 4.1 below outlines our performance targets for the AA5 period.

4.1 Overview

Our Final Plan proposes to maintain the strong performance we have delivered in AA4, while delivering a

Figure 4.1: Our performance targets in AA5

Vision	Which means	2021 to 2025 Target
Delivering for customers	• Public safety • Reliability • Customer service	• Maintain leading public safety performance by maintaining zero primary loss of containment on the DBNGP • Maintain system reliability at or near 100 %, meaning no curtailments of supply to our customers • Improve our customers' satisfaction with the services we provide over the period • Inform our plans through ongoing engagement with our customers
A good employer	• Health & Safety • Employee engagement • Skills development	• Continued focus on achieving zero harm by driving Lost Time Injuries (LTIs) and our Total Recordable Injury Frequency Rate (TRIFR) toward zero • Top quartile employee engagement to ensure our workforce remains customer and safety focused • Maintain compliance with mandatory training requirements above 98 %
Sustainably cost efficient	• Working within industry benchmarks • Delivering profitable growth • Environmentally and socially responsible	• Deliver a $241 million reduction in our revenue while maintaining our service levels • Deliver our expenditure programs within allowances • Improve and strengthen our incentives for efficiency • Operate within our established emissions benchmarks and position the DBNGP to serve customers into the future as the emissions intensity of the Western Australian energy sector decreases • Continue to achieve zero reportable environmental incidents

$241 million (13%) reduction in the revenue we will recover in AA5.

Our plans support our vision to be the leading gas infrastructure business in Australia by achieving top quartile performance on our targets.

We are also responding to changes in the energy sector by planning for the long-term use of our assets in a carbon-constrained economy.

4.2 Delivering for customers

Delivering for customers means maintaining our record of public safety and continuing to provide reliable and high-quality services that customers value.

Our customers expect strong reliability from our services, which is more challenging as the energy sector changes. Increasing penetration of renewable electricity into the SWIS is changing the way the DBNGP is used. We expect more volatility as we respond to the demands of gas-fired generation in the SWIS being used to offset the peaks and troughs of renewable electricity production. This makes achieving 100% reliability more challenging than it has been in the past. Our plans respond to these developments to ensure we continue to meet customer expectations for reliability.

During the AA5 period we will deliver for our customers with lower prices while maintaining service standards:

- reducing revenue by $241 million (or 13%) compared to AA4 helping to minimise our prices;
- offering a Full Haul reference price of $1.43 per GJ ($ 2020), a 4% increase compared to the current reference price and 6% below current negotiated prices as paid by most of our customers.
- maintaining our public safety performance with no losses of primary containment of an energy source;
- maintaining the reliability of the DBNGP at or near 100%;
- continuing to offer Full Haul, Part Haul and Back Haul reference services consistent with feedback from our customers;
- continuing to provide responsive and efficient field works, asset maintenance and customer service; and
- investing $160 million in capex projects.

Our capex investments which deliver for customers include safety and reliability initiatives such as:

- replacement of the obsolete northern communications network (completing the replacement program for our communications network);
- replacement of a number of obsolete control systems; and
- undertaking continuing programs of work such as dry gas seal and valve replacements, hardware and software upgrades and cathodic protection.

4.3 A good employer

To be a good employer we focus on the health and safety of our employees, employee engagement and the skills of our workforce. In AA4 we demonstrated strong performance in all three areas and our Final Plan for AA5 maintains this performance.

We will be a good employer by:

- targeting Zero Harm;
- continuing ongoing health and safety initiatives such as undertaking audits, reporting and investigating incidents, and providing employee training;
- achieving employee engagement scores in the top quartile of our industry;
- investing $22 million on capex projects focussed on employee safety and wellbeing.

Our capex investments to be a good employer include:

- redevelopment of our Jandakot depot; and
- renovations to remote accommodation.

4.4 Sustainably cost efficient

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

Figure 4.2 summarises the regulatory building blocks, demand and price in AA4 and AA5. We will deliver lower costs compared to AA4, even while facing a number of upward cost pressures such as IT support and field expenses.

Our Final Plan is sustainably cost efficient as it:

- proposes an opex (excluding SUG) reduction of $17 million (4%) compared to our actual opex in AA4, while maintaining at or near 100% system reliability of the pipeline;
- forecasts a reduction in SUG expenses to $107 million, almost half the AA4 allowance;
- delivers a capex program which is prudent, efficient, in line with good industry practice and appropriately balances our costs and risks over time;
- proposes $17 million in IT and communications capex projects

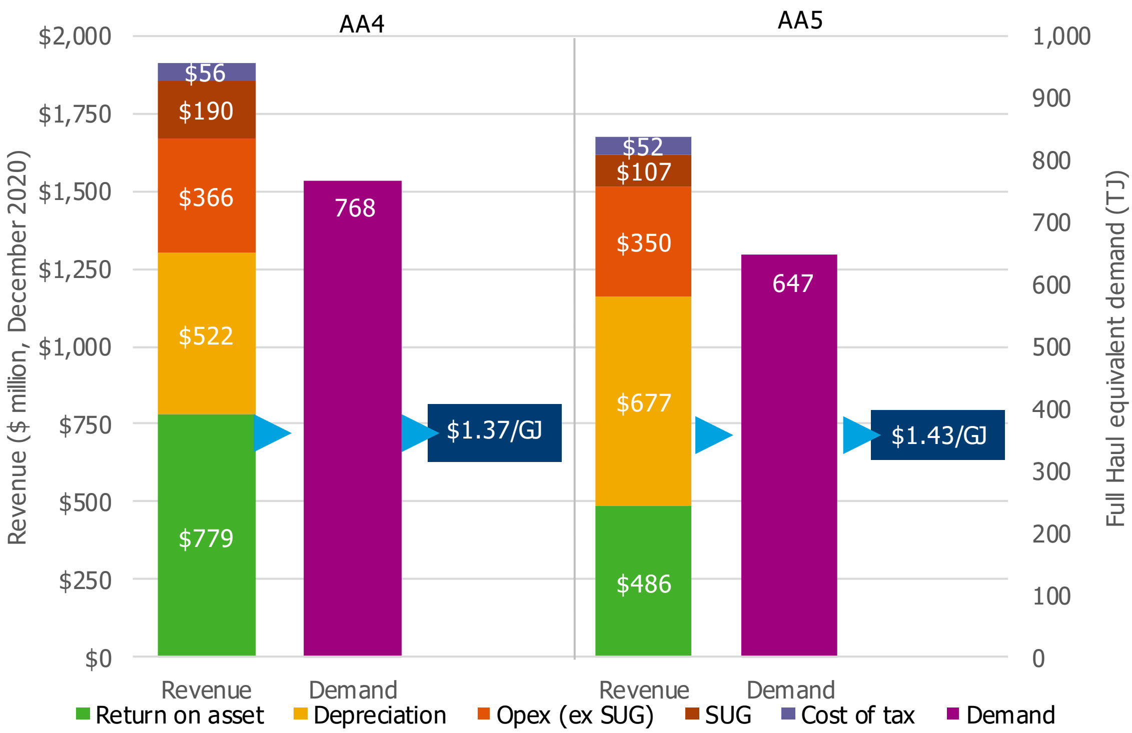
including increased investment in cyber security, data management, digital capabilities and modernising our IT systems;

- sets current asset lives consistent with industry practice;
- recognises the economic life of the DBNGP in the context of the changing energy market;
- calculates financing costs consistent with the ERA's Final *Rate of Return Guidelines* (the Guidelines or the ERA Guidelines);
- is based on the forecast demand for our reference services as informed through engagement with our customers and reviewed by independent experts;
- strengthens our incentives to incur efficient opex by proposing the introduction of an efficiency benefit sharing scheme;
- proposes total revenue in AA5 that is $241 million (13%) lower than total revenue in AA4; and
- proposes to recover revenues from our Full, Part and Back Haul reference services consistent with the current approach supported by our customers.

4.5 Summary

Our plans for AA5 will ensure that we continue to deliver a safe and reliable supply of natural gas to our customers. We will deliver a significant reduction in the revenue that we recover from our customers, while maintaining service standards and addressing the long-term future of the pipeline.

Figure 4.2: Summary of regulatory building blocks, demand and price in AA4 and AA5



5 Customer and Stakeholder Engagement

We actively engaged with customers and stakeholders to inform and shape our Final Plan.

IN THIS CHAPTER

We engaged with our customers and stakeholders to understand how they wanted to be involved in the development of our plans

We held a series of Shipper Roundtables to develop our plans with our customers

We provided customers and stakeholders with the opportunity to comment on all aspects of our plans

We have engaged extensively with our customers and stakeholders to develop a plan that will deliver value for customers in AA5 and beyond.

We adopted a staged approach to our engagement program to support the development of our plans, including the publication of our Draft Plan for consultation in May 2019.

A key aspect of our program was a series of Shipper Roundtables to explain our plans and receive feedback from our customers.

Effective stakeholder engagement is key to developing a plan that delivers for current and future customers and is capable of acceptance. It is integral to achieving our 'no surprises' approach.

This chapter explains our approach to stakeholder engagement and outlines how the program has influenced our plans for AA5.

5.1 Overview

We are committed to effective engagement with our customers and stakeholders.

We began in July 2018 by publishing *Engaging Stakeholders on our Future Plans* (Attachment 5.1) which outlined our proposed approach to engaging with customers and stakeholders in the development of our plans. In this document we also asked for feedback on the most important aspects of our services and issues we should be considering in our future planning for the pipeline.

Our customers told us they value reliability and price, noting that for many customers gas is a critical input into their business operations.

Other topics of interest that were raised included opportunities to improve customer experience, transparency of products and services, and flexibility of solutions for customers in the future. Also discussed were the

many changes to the energy industry, with a focus on renewable energy to decarbonise energy supplies. With increased diversity of energy sources, some stakeholders were uncertain about the future role of gas in a low emission energy future.

Key insights from our early engagement enabled us to focus on the topics of interest to customers in subsequent engagement activities.

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

Feedback was used to inform our final engagement strategy – ensuring our activities were appropriate and allowed effective engagement.

In September 2018 we published our *Stage 1 Stakeholder Engagement Report* (Attachment 5.2) which summarised key insights from our early engagement and documented our final engagement plan.

In October 2018 we commenced the next stage of our engagement program, namely a series of Shipper Roundtables.

The Shipper Roundtables were established to consider and advise on key topics and issues of interest. The Shipper Roundtable meetings were facilitated and documented by an independent third party, KPMG (Attachment 5.4 – *KPMG Customer Engagement Report*).

Through a series of nine meetings, we consulted with customers on the key elements that make up our Final Plan:

- pipeline services;
- customer experience and flexible solutions;
- tariff structure;
- capex proposals
- opex proposals;
- demand forecast;
- rate of return;
- incentives;
- setting our regulated asset base; and
- our role in future energy models.

Feedback from Shipper Roundtables has been captured and used to shape and inform this Final Plan.

In May 2019 we published a Draft Plan for public consultation for a six-week period. We distributed our Draft Plan widely and encouraged feedback and formal submissions. We met with interested parties one-on-one and documented all feedback.

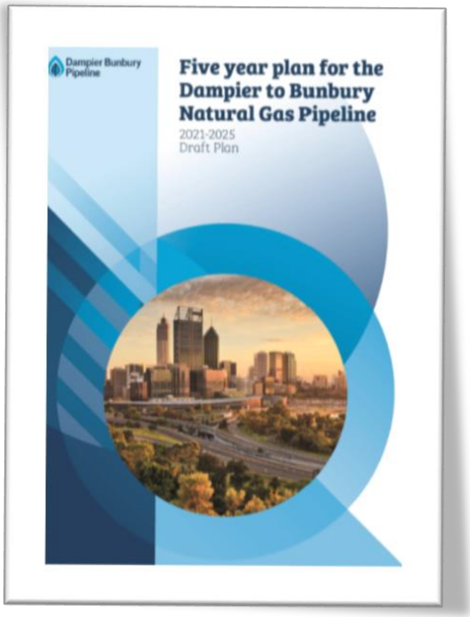
5.1.1 Engagement Informing Our Plans

Our key objective is to deliver a plan that is underpinned by effective stakeholder engagement and is capable of being accepted by our customers and stakeholders.

Our aim is to be open and transparent in our approach and we have sought and responded to feedback throughout the process of developing our plans.

"The theme of no surprises was consistently held throughout nine Shipper Roundtable meetings. AGIG methodically worked through key areas relevant to the development of plans for the future", KPMG (Attachment 5.4)

Our engagement activities commenced 18 months prior to lodgement of this



Final Plan. This has facilitated customer and stakeholder involvement from the very early stages of development, on our Draft Plan through to developing our Final Pan.

Our engagement activities have informed this Plan. We have:

- clearly documented feedback and how we have responded in each chapter;
- clearly demonstrated where there has been customer and stakeholder support for our proposals; and
- been transparent where there hasn't been support from all customers and stakeholders on issues or proposals.

We have documented our process and transparently reported on how feedback has been used across the four stages of our engagement plan.

A summary of all customer and stakeholder feedback, and how it has informed our Final Plan, is included in Table 5.7.

5.2 Our Stakeholders

Given the important role the DBNGP plays in Western Australia, numerous stakeholders have an interest in our transmission business.

Our key stakeholder groups, as shown in Figure 5.1, represent our customers, other pipelines connected to the DBNGP and other businesses in the gas supply chain. Government departments and agencies are identified as a stakeholder group recognising the key role played by the DBNGP in Western Australia's energy security.

Figure 5.1: Stakeholder Map

5.3 Our Approach to Stakeholder Engagement

We are committed to effective engagement practices. We adopted a series of engagement principles to guide how we engaged, which were reviewed and endorsed by our Shipper Roundtable members. Our engagement principles are illustrated in Table 5.1.

We have adopted a four-stage approach to engage and involve customers in our planning process, which is shown below in Figure 5.2.

<u>Stage 1: Strategy and Research</u>

Stage 1 was a research stage to better understand customer and stakeholder needs and expectations. It included consultation on our proposed engagement strategy. This was important to ensure we engaged in a way which met customer and stakeholder expectations.

We sought to understand who our key stakeholders are and how they wanted to be engaged. In concluding Stage 1 we released a Stage 1 Report summarising customer and stakeholder feedback, and our final engagement strategy.

Figure 5.2: Our Four Staged Engagement Approach

Stage 2: Developing our Plan

Stage 2 included targeted engagement activities on our investment proposals and regulatory modelling. In this stage we ran a series of Shipper Roundtable meetings, consulting on key topics to guide the development of our plan.

Stage 3: Consultation on our Draft Plan

In Stage 3 we consulted on our Draft Plan, which we published in May 2019. We actively engaged with customers and stakeholders through one-on-one meetings in addition to Shipper Roundtable meetings.

Stage 4: Refinement and Ongoing Engagement

Consultation feedback from the Draft Plan as well as feedback gained from further Shipper Roundtable meetings has been used to inform our Final Plan. We will continue our engagement efforts after we submit to the ERA, to ensure our customers and stakeholders can continue to provide input into our plans before the ERA Final Decision is made towards the end of 2020.

This chapter summarises all customer and stakeholder engagement feedback and input across all four stages of our engagement program.

Table 5.1: Our Customer and Stakeholder Engagement Principles

Principle		Our Commitment
Genuine and Committed	✓	We listen and respond to the needs of our customers and stakeholders, driving a culture of delivering value for our customers.
Clear, accurate and timely communication	✓	We provide information that is clear, accurate, relevant and timely
Accessible and Inclusive	✓	We involve customers and stakeholders on an ongoing basis in a meaningful way to ensure that our plans deliver for our customers.
Transparent	✓	We clearly identify and explain the role of customers and stakeholders in the engagement process, and consult with customers and stakeholders on information and feedback processes.
Measurable	✓	We measure success, or otherwise, of our engagement practices to ensure ongoing improvement

5.5 Stage 1 Engagement – Strategy and Research

Between July and September 2018 we undertook several actives to better understand our stakeholder preferences for engagement, and to identify key issues.

5.5.1 Activities

We sent our draft engagement strategy, *Engaging Stakeholders on our Future Plans*, to all key stakeholders, and made the document publically available on our website in July 2018.

We directly contacted 23 shippers, gas marketers and producers, nine Government agencies and departments, seven consumer representative groups, two gas trading agents, and one gas distributor.

In August and September 2018, we met stakeholders to discuss our proposed approach and explore key issues. We held one-on-one consultation meetings with 17 customers and stakeholders.

All meetings were documented, summarised and used to guide our final engagement strategy, including topics for engagement. At the completion of Stage 1 we documented all customer and stakeholder feedback which is included in our final Engagement Strategy in *Stage 1 Stakeholder Engagement Report* (Attachment 5.2).

5.5.2 Key insights

During stakeholder meetings we facilitated discussion around three consultation questions.

- What are the most important aspects of our services?
- What issues should we be considering in our future planning for the pipeline?
- What aspects of our future plans would you like to engage on?

A summary of key insights is captured in Table 5.3.

We also tested our proposed engagement approach with stakeholders, covering key topics such as:

- our engagement approach and stakeholder engagement principles;
- our identification of key stakeholder groups;
- our proposed engagement activities, timeline and reporting.

A summary of all customer and stakeholder feedback received during Stage 1 is captured in Table 5.4.

Table 5.2: Stage One Consultation Questions

Topic	Consultation Question
Our stakeholders	*Have we identified all relevant customer and stakeholder groups?*
Engagement principles	*Are our engagement principles appropriate to develop plans that deliver for our stakeholders and customers?*
Engagement activities	*Are our proposed engagement activities appropriate for our stakeholders?* *How would you like to participate in our process?* *Should we establish a Shipper Roundtable to guide and inform our plans?* *Should we establish a Stakeholder Roundtable with representatives across all our stakeholders?* *Should we establish Roundtables on specific topics?*
Our Future Plans	*What are the most important aspects of our services?* *What issues should we be considering in our future planning for the DBNGP?* *What aspects of our future plans would you like to engage on?*
Approach and Timeline	*Is our proposed approach open and transparent?* *Are there ways to improve our proposed approach?* *Have we allowed sufficient activities and time to allow meaningful engagement to take place?*

Table 5.3: Summary of Stage One Key insights

Delivering for customers today	Delivering for customers in the future
Reliable services	Future energy models
• **Reliability** – Our customers place a high value on the current levels of reliability • **Price** - Reliability and price are two of the most important considerations for customers and are often raised together • **Critical for business operations** - Some businesses receiving gas via the pipeline are highly reliant on gas as an input into their business operations • **Operational maintenance** - It was noted that maintaining a strong focus on operational issues is important for both reliability and emergency management	• **Uncertainty** - Many stakeholders noted the rapid changes to the energy industry with a focus on renewable electricity to decarbonise energy supply, in particular that they were uncertain about the future role of gas and the DBNGP more specifically • **Changes to the energy mix** - It was noted the diversity of energy sources and an increase in renewable electricity is creating change for energy models which is impacting on infrastructure operation and planning (e.g. peakiness of the system) • **Renewable energy** - The future of renewable electricity was a topic of interest, including the potential role hydrogen and biogas may play in the future
Customer experience	Flexible solutions
• **Relationship management** - Our customers value the relationships they have with us and how they are managed by our staff • **Transparency around types of services available** - Customers would like more transparency of products and services that are available • **Pro-active service offerings** - Some customers indicated that we could be more pro-active in offering service improvements as opposed to responding to requests • **Enhanced service experience** - Feedback from customers highlighted there are opportunities to improve customer facing processes such as billing, invoicing, and digital services	• **Innovation** - Customers supported our focus on innovation to ensure the products and services we offer are responsive to the needs of our customers, and the changing dynamics of gas supply • **Gas trading market** - The future of gas trading in Western Australia was commonly raised by customers as an issue for consideration • **Flexible products and services** - Customers expressed an interest in greater flexibility in commercial terms of transportation contracts

Table 5.4: Stage One Summary of Customer and Stakeholder Feedback

Topic	Customer and Stakeholder Feedback	Our Response
Our Engagement Approach and Principles	• Customers and stakeholders noted Stage 1 engagement activities were important to clearly define our stakeholders, the broad areas for engagement and timing. • Customers and stakeholders supported our staged approach to developing our plans, particularly the release and engagement on a Draft Plan. • Customers and stakeholders supported an open, transparent and timely process, with strong support for our 'no surprises' approach.	• We confirmed our four stage approach to develop our Final Plan. • We confirmed our commitment to our engagement principles and 'no surprises' approach.
Our Stakeholders	• Some customers questioned whether we should be engaging with household and small business end-users who are not directly connected to the DBNGP. They considered this relationship should be managed by retailers and/or ATCO Gas. • Consumer representative groups did not want to be directly involved in our stakeholder engagement program. This reflects the low cost impact of our services on the total retail gas bill (on average DBNGP costs account for 3% of a household gas bill). • For similar reasons, other stakeholder representative groups indicated they did not want to be directly involved in our engagement program.	• We focused our engagement program on customers directly connected to the DBNGP (and their representatives). We have revised our stakeholder map accordingly. • We kept other stakeholders updated on our progress, including through the release of our Draft Plan. • We considered the outcomes of other engagement programs where relevant, particularly the recent engagement undertaken by ATCO Gas.
Key Insights	• Customers highly value current reliability levels. • Customers value our current relationship but also noted ways their customer experience could be improved. • Customers highlighted the importance of flexibility to ensure we are responsive to their needs. • Customers noted uncertainty in the ongoing role of the DBNGP as energy supply becomes less carbon intensive (and the related focus on renewable electricity).	• We explored these key insights with our customers as we developed our Draft and Final Plans.
Our Engagement Activities	• Customers were keen to be involved in our stakeholder engagement program, although the level of involvement was variable. • Customers supported establishing a Shipper Roundtable and considered this was an efficient way for us to receive input into the development of our plans. • Customers also value regular one-on-one meetings and expect these to continue through the development of our plans. • Consumer and stakeholder representative groups indicated they would like to be kept informed of our progress and plans. • Digital updates and fact sheets were considered an efficient way to keep stakeholders informed. • The ERA indicated it may participate in our engagement activities as an observer, noting it could also be kept informed of our progress through ongoing one-on-one meetings and there may be opportunities to engage with its CCC.	• We established a Shipper Roundtable as a key part of our engagement program. We invited all Shippers to be a part of the roundtable. • We engaged with our customers through a series of one-on-one meetings. • We provided regular stakeholder updates, which will provide an opportunity for any stakeholder to become involved.
Our Timeline	• Customers and stakeholders supported our timeline.	• We confirmed the timeline for developing our plans.

5.6 Stage 2 Developing Our Draft Plan

In Stage 2 we delivered engagement activities based on customer and stakeholder preferences in Stage 1.

During Stage 2 we held five Shipper Roundtable meetings. A summary table of meetings and topics is provided in Table 5.5.

During Stage 2 we:

- provided shippers with background and contextual information about the DBNGP and our vision and values;
- discussed our approach to working together with shippers to deliver a plan which is capable of acceptance by our customers and stakeholders;
- provided an overview of the regulatory building blocks to provide transparency and clarity around how prices are set;
- consulted with shippers on Pipeline and Reference Services;
- provided shippers with our price modelling information (January 2019);
- provided shippers with our proposals for both opex and capex;
- provided shippers with early demand forecast; and
- discussed how we deliver in the long-term interest of our customers (future focus).

A summary of all customer feedback in Stage 2 (together with feedback received in Stages 3 and 4) is shown in Table 5.7.

Shipper Roundtables

In September 2018 we invited all direct customers and gas trading agents to be involved in a series of Shipper Roundtables.

The Shipper Roundtables were established as a forum for AGIG to actively engage Shippers in the development of its plans for 2021 to 2025.

A total of nine meetings were held between October 2018 and November 2019.

Shipper Roundtable meetings were a critical input and valuable way to work together with customers to shape our plans.

- ✓ 85% of Shippers attended one or more Roundtables
- ✓ Attendance at Roundtable meetings more than doubled over time
- ✓ We proactively shared information early with Shippers to get input and ensure 'no surprises'
- ✓ We shared our Draft Plan seven months early to capture feedback and allow for meaningful engagement
- ✓ We publicly reported all agendas, minutes and presentation materials online (gasmatters.agig.com.au)

Meetings were facilitated by a third party (KPMG) to ensure independence in the documentation of feedback. Shippers were offered the opportunity to provide feedback during or after meetings.

KPMG offered one-one-one stakeholder feedback sessions at any time. We encouraged Shippers to request any additional information that may assist in understanding our plans.

KPMG independently surveyed Shipper Roundtable members after meeting 8 to assess how AGIG had performed against its engagement principles and found that:

100% of Shippers agreed that the Shipper Roundtables had provided a useful format to engage with AGIG as part of its AA5 Submission.

91% of Shippers agreed that AGIG had adopted a 'no surprises' approach.

82% of Shippers agree that the 2021-2025 Plan is representative of presentations and discussions at Shipper roundtables (noting the remaining respondents were neutral, no Shippers disagreed).

Full survey results are included in KPMG's Shipper Roundtable engagement Report (Attachment 5.4).

Table 5.5: Summary of Shipper Roundtable Meetings

Stage	Meeting	Key Topics	Summary of information presented
Stage 2: Developing our Draft Plan	Meeting 1	Our Engagement Approach Pipeline Services	• Our Stakeholder Engagement Approach – including key objectives, timelines • Role of the Shipper Roundtable • Key Insights from Stage 1 Engagement • An overview of pipeline services we currently offer on the DBNGP and our proposed reference services
	Meeting 2	Customer Experience/ Flexible Solutions	• Confirmation of our proposed reference services • An overview of our current tariffs and tariff structure • Opportunities to improve customer experience • Our customer satisfaction survey and recent results • AGIG's customer experience aspirations
	Meeting 3	Our Capital and Operating Expenditure Proposals	• Follow up information on customer experience actions • Regulatory process overview • Early price modelling • Regulatory building block model • Operating framework for our expenditure proposals • Proposed capex and opex proposals for AA5
	Meeting 4	Rate of Return Demand Forecast Incentives	• Additional information relating to proposed capex and opex proposals for AA5 • Demand forecast • Our proposed approach to Rate of Return • Incentives
	Meeting 5	Future Focus	• Regulatory modelling - price and demand update • Additional information on demand including SUG • Incentives, our AA5 proposal • Future focus, including decarbonisation • Asset categorisation • Regulated Asset Base, recovery profile • Regulatory Building Blocks for AA5 • Engagement on our Draft Plan
Stage 3 – Consultation on the Draft Plan	Meeting 6	Draft Plan	• Draft Plan overview • Proposed price • How the Draft Plan delivers for customers in AA5 • Consultation process
Stage 4 – Refining and Ongoing Engagement	Meeting 7	Draft Plan Feedback	• Summary of feedback and AGIG response • Refining our plans • Gas Matters, online engagement platform
	Meeting 8	Refining our Plans	• WACC update and price modelling • Depreciation Supporting Information Paper • KPMG Assurance Review (Demand Forecast) • Terms and Conditions
	Meeting 9	Refining our Plans	• Our Final Plan (2021 – 2025) • KPMG Reporting

5.7 Stage 3 Consultation on our Draft Plan

In Stage 3 we published and consulted on our *Draft Plan* (Attachment 1.2).

The Draft Plan was published on the DBP and AGIG websites on 17 May 2019. The Draft Plan was distributed widely to stakeholders including all customers, Government agencies, other pipeline owners (e.g. ATCO Gas) and regulators.

The Draft Plan was open for public consultation for a six-week period and closed on 28 June.

We presented our Draft Plan to Shippers at Shipper Roundtable 6 on 20 May 2019 and feedback was provided during the session.

To facilitate effective engagement, the Draft Plan:

- highlighted key issues of importance that had been identified by our customers and stakeholders;
- showed how we have considered and responded to feedback in developing our proposals;
- demonstrated how we propose to deliver in the long-term interests of customers and stakeholders; and
- asked a series of consultation questions to facilitate engagement on key topics and regulatory drivers of our plan as shown in Table 5.6.

We held one-on-one meetings with our customers where we captured and documented their feedback. We also received a written submission from a Shipper which is included in Attachment 5.3.

As part of our consultation on the Draft Plan we received very positive feedback regarding our engagement activities, in particular that:

Table 5.6: Stage Three Consultation Questions

Topic	Consultation Question
What we will deliver	*Do you have any feedback on our targets for AA5, including whether our targets are consistent with feedback received through our stakeholder engagement program so far?*
Customer and Stakeholder Engagement Program	*Do you have any feedback on our customer and stakeholder engagement program?* *Have we considered customer and stakeholder feedback and responded appropriately in the Draft Plan?*
Pipeline and Reference Services	*Do you think the Pipeline and Reference Services we have proposed are appropriate?*
Operating and Capex	*Do you support our approach for forecasting opex and capex?* *Have we provided sufficient information to understand our proposals and the basis of the costs included?*
Capital Base	*Is our approach to adjusting the capital base, including our assumed asset categories, asset lives and aligning the economic life of the main and loop lines, appropriate?*
Financing Costs	*Do you have any comments on our approach to setting the financing and tax costs in the Draft Plan?*
Demand	*Do you support our approach to forecasting demand?* *Are there any other factors you think we should consider?*
Incentives	*Do you support our proposal to introduce an opex efficiency benefit sharing scheme (EBSS)? Are there any additional considerations that should be incorporated into an opex EBSS?* *Do you support our proposal to introduce an innovation scheme?* *Are there any additional considerations that should be incorporated into an innovation scheme?* *What level of allowance should be allowed under any proposed innovation scheme?*
Revenue and Prices	*Have we provided enough information to understand the basis of our proposed price, including how it is split between the capacity and commodity components?*
Other	*Is there anything that our Draft Plan hasn't considered that it is important to you?*

"*the process had provided transparency on the building blocks and enabled a good degree of understanding of the method used to determine the reference tariff*";

and

"*that shippers were appreciative of Roundtable discussion including the format, openness, content and that they were kept informed and provided input into changes to decisions or positions as they occurred*";

and

"*that a 'no surprises' objective had been achieved'.*

(KPMG Customer Engagement Report December 2019, Attachment 5.4)

Customers indicated a general level of comfort with the Draft Plan.

Key areas of feedback from Stage 3 engagement in relation to the Draft Plan included:

- support for our Pipeline and Reference Services with some additional information requested (e.g. terms and conditions);
- more detailed information on opex and capex proposals was requested (e.g. derivation of costs);
- more information around benchmarking and the efficiency of our costs was requested;
- support for the approach to asset re-categorisation of our asset base with additional visibility of the mapping;
- more information on the rationale for aligning the economic life of the loop and the mainline was requested;
- more information and detail on the demand forecast was sought, noting that customer confidentiality needs to be preserved;
- support for an opex EBSS applying in AA5; and
- no support for a capex, customer service or an innovation incentive scheme to apply in AA5.

All feedback captured during Stage 3 is documented in Table 5.7.

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

Resources include

- ✓ Stage 1 and 2 Engagement Reports
- ✓ KPMG Customer Engagement Report
- ✓ All Shipper Roundtable Meeting agendas, presentation materials and minutes
- ✓ Depreciation Supporting Information Paper
- ✓ KPMG Demand Assurance Review

5.8 Stage 4 Engagement – Refining our Plans

In Stage 4 we addressed all feedback from stakeholders during the Draft Plan consultation. This information was used to guide and shape our Final Plan.

Feedback received during Stages 3 and 4, and how we have responded in our Final Plan, is summarised in Table 5.7

All information requests were responded to in Shipper Roundtables 7, 8 and 9.

5.8.1 Key topics for further exploration

Customers were particularly interested in further discussion and understanding around two key issues: demand forecasting for AA5 and our approach to depreciation.

In order to help customers understand these issues in detail, we undertook two pieces of work:

- Depreciation Supporting Information Paper (which has been updated and provided as Attachments 9.1 and 9.2); and
- KPMG Reasonable Assurance Report on Demand Forecasts (Attachment 11.1).

In August 2019 we circulated to Shipper Roundtable participants an information paper relating to our position on depreciation. The information paper provided customers with supplementary information and detail regarding the reasoning for our approach. We sought feedback on this paper at Shipper Roundtables 7 and 8.

Customers also requested more detail on our demand forecasting, while recognising the need to maintain confidentiality around individual Shipper forecast demand information supplied to AGIG.

We engaged KPMG to undertake a Reasonable Assurance Review to provide an independent assessment of our demand forecast, including our forecast of contracted capacity and throughput for reference services during AA5.

As part of the review, we provided KPMG with access to detailed forecast information and actual contracted capacity and throughput in AA4. All information provided to KPMG as part of the review was under a strict confidentiality agreement.

The Assurance Review Report was made available to all customers by KPMG (Attachment 11.1). We also held a teleconference with interested customers in October 2019 to respond to any queries or questions.

5.9 Summary

We have actively engaged with customers and stakeholders to inform this Final Plan.

All customer and stakeholder feedback received during the engagement program is summarised in Table 5.7 over leaf. The table shows how we have listened and responded to all feedback. Final plan outcomes are also included in the table to demonstrate how engagement has shaped our proposals, and are illustrated as follows:

	• Positive/Green – we have responded to all feedback and have customer/stakeholder support for our proposal
	• Neutral/Orange – we have responded to customer and stakeholder feedback, but we do not have full support of all customers/ stakeholders
	• Negative/Red – we have not responded to customer feedback and we do not have customer/ stakeholder support for our proposal

Table 5.7: Customer and Stakeholder Feedback Summary

Topic	Customer and Stakeholder Feedback	Our Response
Pipeline and Reference Services	**Stage 1 and 2 Engagement : Developing our Plans**	
	• Customers value transparency around the products and services that are available. • Customers requested that additional detail related to services be included on the DBP website. • Agreement that Reference Services should be consistent with those offered in AA4 (Shipper meetings 1 and 2).	• We provided information to customers during Shipper Roundtable Meetings 1 and 2 including an overview of current services, and definition of reference and non-reference services. • We updated the DBP website to include more information of all services provided to customers in March 2019. • We have proposed Full Haul, Part Haul and Back Haul Reference Services consistent with the current Reference Services, noting that we will continue to negotiate bespoke services with customers.
	Stage 3 Engagement : Draft Plan Consultation • **Do you think the Pipeline and Reference Services we have proposed are appropriate?**	

	• Customers supported the proposed Full Haul, Part Haul and Back Haul Reference Services consistent with the current Reference Services.
	• Customers requested information on the relative importance of reference services and non-reference services for our revenues.
	• Customers requested that any potential changes to terms and conditions be identified.
		• At Shipper Roundtable Meeting 7, we provided further information to customers noting:
		  • The distinction between Reference Service Contracts and the Standard Shipper Contracts (SCC).
		  • That non-reference service revenue in the previous 3 years ranged from 2-5% of revenue and is highly variable year on year.
		• We provided customers with our proposed changes to Reference Service Terms and Conditions in November 2019, with comments provided prior to submission of the Final Plan.

	Stage 4 Engagement: Refining our Plans	
	• Customers requested that a list of proposed amendments to the terms and conditions be circulated and discussed.	• On 15 November 2019 we circulated for consultation a table of proposed amendments and a mark-up of the Reference Service Terms and Conditions for T1, P1 and B1 Reference Services. We sought feedback by 2 December 2019, however we noted the tight timeline and offered to continue to engage with shippers through the new year.
	Final Plan Outcome	
	• Our proposal provides transparency around the services we provide, which are valued by our customers. • Our proposal for Full Haul, Part Haul and Back Haul Reference Services is consistent with the current Reference Services and is supported by customers and stakeholders.	

Topic	Customer and Stakeholder Feedback	Our Response
Operating expenditure	**Stage 1 and 2 Engagement : Developing our Plans**	

	• Customers highly value current levels of safety and reliability.
	• Customers are keen to ensure opex is efficient.
	• Maintaining a strong focus on operational issues is important for reliability and emergency management.
	• Customers requested clear visibility of changes in forecast opex between AA4 and AA5.
	• Customers requested additional information relating to the proposed 94/6 split between fixed and variable opex costs.
	• Customers queried the opex of turbines and GEAs.
		• We prepared draft opex proposals focused on maintaining current levels of system reliability.
		• We provided information to customers on the cost categories that are increasing in AA5 and included this in our Draft Plan for comment, and in this Final Plan.
		• At Shipper Roundtables 3 and 4 we provided detailed information regarding turbines and GEAs, including:
		  ◦ the treatment of turbines and GEA overhauls as opex, rather than capex;
		  ◦ the cost split between turbines and GEA overhauls;
		  ◦ the DBNGP operating profile including run hours, maintenance schedule and activities to ensure efficient operation, noting critical stations and the impact of stop-start costs and other network impacts on overhauls.
		• We provided supporting information in our Draft Plan, and have included this information in our Final Plan, as requested by customers relating to how our spend compared to previous years, and where there had been areas of change (e.g scheduling of overhauls).

	Stage 3 Engagement : Draft Plan Consultation • **Do you support our approach to forecasting opex?** • **Is there sufficient information to understand our proposals and the basis of the costs included?**	

	• Customers were interested in more detail regarding the derivation of costs.
	• Customers wanted further transparency on the difference between opex and capex activities relating to turbines and GEAs.
	• Customers want to ensure that costs are efficient and questioned whether there should be benchmarking costs against similar pipeline businesses.
	• Customers would like to see trends in fuel efficiency over previous AA periods.
		• At Shipper Roundtable 7, we explained the supporting information that is included in the Final Plan including assurance of actual spend in the current period, and project and program business cases and supporting models (Attachment 7.2). Customers agreed that this was sufficient information.
		• We discussed efficiency and benchmarking with customers at Shipper Roundtable 7 and 8 including:
		  ◦ a presentation of data illustrating that opex per unit of total energy delivered and opex per km has reduced over time;
		  ◦ highlighting that while we value benchmarking, sourcing benchmarking data for transmission pipelines is challenging, particularly given the uniqueness of the DBNGP.

Topic	Customer and Stakeholder Feedback	Our Response
Operating Expenditure	**Stage 4 Engagement: Refining our Plans**	
	Customers requested more information in relation to the change in forecast opex from AA4 actual to AA5.	• We provided additional information at Shipper Roundtable 8, highlighting that the key driver behind the $27 million increase period-on-period is the change in capitalisation policy (approximately $12 million) to better reflect the nature of these costs. We have provided independent advice that this is reasonable under accounting principles in this Final Plan (see Attachment 7.4).
	Final Plan Outcome	
	• Our opex proposal delivers against customer expectations that current levels of safety and reliability are maintained. • Our opex proposal is responsive to customer needs for a strong focus on operational issues, which is important for reliability and emergency management. • Our Final Plan provides required supporting information on opex, and evidence that we are cost efficient, specifically Attachments 7.1, 7.2, 7.3 and 7.4. • Customers are comfortable with our approach to forecasting opex., noting it is consistent with the ERA's preferred methodology.	

Topic	Customer and Stakeholder Feedback	Our Response
	Stage 1 and 2 Engagement : Developing our Plans	

Capital expenditure	• Customers told us they highly value current levels of reliability and would be concerned if this were to change.
	• Maintaining a strong focus on operational issues is important for reliability and emergency management.
	• Customers requested more information on changes in capex between AA4 and the forecast AA5.
	• Customers asked for clarification on the potential cost duplication of turbine overhauls.
	• One customer asked for clarification on our tender and contracting processes.
	• Customers support an improved customer experience (IT investment) where there is a business case to do so.
	• Customers requested information on:
	  – how we ensure we deliver our capex program efficiently;
	  – how our demand forecasts have been factored into our capex program;
	  – how we deal with changing business needs during an AA period.
		• We provided explanatory information in our Draft Plan, and further information in this Final Plan in Chapter 8, to provide information for customers on our capex spend, including comparative spend with AA4 and how we have demonstrated our forecast is prudent and efficient.
		• We provided clarity to customers on why overhauls are considered to be opex.
		• Our Final Plan does not propose major investment in improved customer experience, but rather proposes that small improvements would be made to billing within existing system improvements.
		• An overview of our tender and contracting process was summarised in our Draft Plan.
		• Our Final Plan includes copies of our Procurement Policy and Purchasing Procedure at Attachments 8.9 and 8.10.

	Stage 3 Engagement : Draft Plan • **Do you support our approach to forecasting capex?** • **Is there sufficient information to understand our proposals and the basis of the costs included?**	
	• Customers were interested in more detail regarding the derivation of costs. • Customers wanted further transparency on the difference between opex and capex activities relating to turbines and GEAs. • Customers want to ensure that AGIG's costs are efficient. • Customers noted that our approach to governance is consistent with what they would expect to see.	• At Shipper Roundtable 7, we explained the supporting information that is provided in the Final Plan including our Asset Management Plan (Attachments 8.1 and 8.2), Stay in Business Capex Plan (Asset Replacement Plan), Cost estimation methodology and IT Investment Plan. Customers agreed that this was sufficient information.
	Stage 4 Engagement: Refining our Plans	
	• No further information was requested in relation to capex.	• This Final Plan reflects feedback from Shippers in Stages 1 to 3.
	Final Plan Outcome	
	• Our capex proposal delivers against customer expectations that current levels of reliability are maintained. • This Final Plan provides supporting information on capex and evidence of our governance arrangements that support cost being efficient. • Customers are comfortable with our approach and level of capex.	

Topic	Customer and Stakeholder Feedback	Our Response
Future Focus and Capital Base	**Stage 1 and 2 Engagement : Developing our Plans**	

	• Customers acknowledged the increasing use of renewable electricity and resultant uncertainty around future energy models.
	• Many stakeholders noted the rapid changes to the energy industry with a focus on renewable energy to decarbonise energy supply and electricity specifically; there was uncertainty about the future role of gas and the DBNGP more specifically.
	• Customers asked if an early recovery of depreciation will impact on the price in the future.
		• At Shipper Roundtable 5 we discussed how a future focus is a key consideration in our approach to asset categorisation and depreciation – in order to deliver in the long-term interests of customers.
		• We proposed our approach to the capital base is to:
		  • align asset categories and lives with good industry practice, including by having regard to other transmission pipelines in Australia; and
		  • examine the economic life of our longest-lived assets and the DBNGP system as a whole.
		• We have ensured that the price impacts of our depreciation proposals are made clear to customers as our plans are developed and in our Final Plan in Chapter 9.

	Stage 3: Draft Plan Consultation • **Is our approach to adjusting the capital base, including our assumed asset categories asset lives and aligning the economic life of the main and loop lines appropriate?**	

	• Customers supported our approach to asset categorisation but would like visibility of the mapping.
	• Customers requested more detail on the change in economic lives, including evidence of regulatory precedent.
	• Customers asked for information on the rationale for considering the economic life of the DBNGP system as a whole.
	• Customers asked for evidence that supported the proposal to act now on accelerated depreciation.
		• At Shipper Roundtable 7, we showed a mapping of asset categorisation differences between AA4 and AA5.
		• In August 2019 we circulated to Shipper Roundtable participants an Information Paper relating to our position on depreciation. The Information Paper provided customers with supplementary information and detail regarding the rationale in response to Draft Plan feedback. It was prepared to facilitate more in depth engagement with our customers. Our Final Plan provides a further update to the information provided at Attachments 9.1 and 9.2.
		• Additional information regarding depreciation and asset lives was presented to customers at Shipper Roundtable 7 and 8, including:
		  • an overview of the economic modelling evidence that supports acting now (e.g. WOOPs model, future carbon scenarios); and
		  • further evidence on the decarbonisation transition taking place in the energy industry.

Topic	Customer and Stakeholder Feedback	Our Response
	Stage 4 Engagement : Refining our Plans	
	• Some customers questioned whether there was enough evidence available to support our proposed approach to depreciation to reflect a revised economic life. • Customers queried the price impact of the proposed approach to depreciation of the loop line.	• We provided the best available price impact information to customers to facilitate the discussion based on forecast modelling, indicating a price impact of $0.6-0.8 per GJ due to the changing depreciation profile of the DBNGP. • We continued discussions with customers regarding depreciation, noting that while there was broad recognition and acceptance of an uncertain future, some customers were not actively supporting the proposal. • Our Final Plan provides further information on our depreciation proposals in Chapter 9 including detailed supporting information in Attachments 9.1 and 9.2, and a report from ACIL Allen on the framework adopted at Attachment 9.3.
	Final Plan Outcome	
	• Our Final Plan provides comprehensive supporting information and rationale for our proposed approach to depreciation of our capital base. • Our rationale for asset recategorisation was understood by our customers and stakeholders as reasonable and consistent with good industry practice.	
	• There is broad recognition and acceptance by customers and stakeholders that the future of the DBNGP is uncertain given the rapidly changing renewable energy market, consistent with the challenges that many of our customers face. Some customers accepted the need to amend the overall asset life to match a revised economic life, however some customers reserved their position until we provide our Final Plan.	

Topic	Customer and Stakeholder Feedback	Our Response
Financing Costs	**Stage 1 and 2 Engagement : Developing our Plans**	
	Customers were keen to understand how AGIG intends to calculate the rate of return.	• We advised that we have applied the ERA's *Rate of Return Guidelines* to calculate the rate of return to meet the objective of a plan capable of acceptance, noting the Guidelines had not been finalised when we provided this assurance in the Shipper Roundtable meetings. • In January 2019 we provided an estimate of 5.6% with a forward estimate of 5.99%, and then in March we updated the estimate to 5.39% (based on information available at the time).
	Stage 3 Engagement : Draft Plan Consultation • **Do you have any comments on our approach to setting the financing and tax costs in this Draft Plan?**	
	Customers acknowledged AGIG's intention to adopt the ERA's the Guidelines in formulating its plans.	• We advised customers that applying the ERA's Guidelines is consistent with the approach taken for other AGIG assets, and that this is consistent with submitting a plan which is capable of being accepted by our customers and stakeholders.
	Stage 4 Engagement: Refining our Plans	
	No further feedback was received.	• In Shipper Roundtable 9 we provided updated building block calculations, including rate of return and tax allowances based on currently available information.
	Final Plan Outcome	
	• We have applied the ERA's *Rate of Return Guidelines* in this Final Plan, and this approach is supported by customers and stakeholders. • The rate of return applied in this Final Plan is 4.31%. • We have also updated our approach to calculating the tax allowance following the release of the ERA Final Decision for ATCO Gas. This had the impact of reducing allowed tax relative to the information provided to customers in October/November 2019.	

<table>
<tr><th>Topic</th><th>Customer and Stakeholder Feedback</th><th>Our Response</th></tr>
<tr><td rowspan="9">Demand</td><td colspan="2">Stage 1 and 2 Engagement : Developing our Plans</td></tr>
<tr><td>- Customers and stakeholders are seeing an increase in renewable electricity in the energy market.
- Customers noted uncertainty about the ongoing role of the DBNGP as the energy system decarbonises, and the related focus on renewable electricity.
- Customers were keen to understand the assumptions underpinning our demand forecast in AA5.</td><td>- We discussed our approach to forecasting demand at Shipper Roundtables 4 and 5, including overviews of:
  - market supply and demand;
  - throughput and end-use by industry sector for 2018;
  - the diversification of current and future supply (e.g. Wheatstone);
  - the current and forecast fuel mix, noting increasing renewable electricity generation facilities in the South West Integrated System (SWIS).
- We presented a Full Haul equivalent demand forecast averaging 691 TJ/Day in January 2019.
- We updated our forecast to an average of 682 TJ/ Day in March 2019 based on updated information that was available.
- We forecast decreasing Full and Part Haul demand and increasing Back Haul Demand in AA5.</td></tr>
<tr><td colspan="2">Stage 3 Engagement : Draft Plan Consultation
- Do you support our approach to forecasting demand?
- Are there any other factors you think we should consider?</td></tr>
<tr><td>- Customers want to better understand how we have forecast demand and how this compares to the Gas Statement of Opportunities (GSOO) and Electricity Statement of Opportunities (ESOO).
- Customers requested information on the sources of generation in the SWIS used for the demand forecast. Information was also requested on the historical use and future forecasts of SUG.</td><td>- We provided further information to customers on the methodology to forecasting capacity, highlighting that there are a number the factors (e.g. relinquishments) that need to be considered when comparing and attempting to reconcile the GSOO and ESOO with our forecast demand for AA5.
- We committed to looking for a way to provide a greater level of assurance in our demand forecast without providing detail that would compromise customer confidentiality.</td></tr>
<tr><td colspan="2">Stage 4 Engagement: Refining our Plans</td></tr>
<tr><td>- Customers requested more detail on our demand forecast, while recognising the need to maintain confidentiality for individual Shipper forecast demand information supplied to AGIG.</td><td>- We engaged KPMG to undertake a Reasonable Assurance Review to provide an independent assessment of our demand forecast, including our forecast contracted capacity and throughput for reference services during AA5.
- The Reasonable Assurance Review report was made available to all customers by KPMG and is included at Attachment 11.2 of the Final Plan.
- We also held a teleconference with interested customers in October 2019 to respond to any queries or questions in relation the Review and our Demand Forecast for AA5.</td></tr>
<tr><td colspan="2">Final Plan Outcome</td></tr>
<tr><td colspan="2">- Our approach to developing the demand forecast in AA5 is supported by customers.
- We have provided additional informational to customers by providing an independent assurance that our forecasting methodology is reasonable, accurate and representative of the best forecast or estimate possible in the circumstances.</td></tr>
</table>

Topic	Customer and Stakeholder Feedback	Our Response
	Stage 1 and 2 Engagement : Developing our Plans	
	- Customers support a focus on innovation to ensure the products and services we offer are responsive to the needs of our customers, and the changing dynamics of gas supply. - Customers highlighted the importance of flexibility to respond to their needs. - Customers noted that price is important and they could see potential benefits in strengthening our incentives for efficient opex. - Customers supported innovation, particularly for renewable energy. - Customers did not indicate support for a CESS or a customer incentive scheme.	- We discussed potential incentive arrangements for opex, capex, service performance and innovation. - In March we presented our plans to only propose an opex and innovation scheme based on feedback received to that point.
	Stage 3 Engagement : Draft Plan Consultation - **Do you support our proposal to introduce an opex efficiency benefit sharing scheme (EBSS)?** - **Are there any additional considerations that should be incorporated into an opex EBSS?** - **Do you support our proposal to introduce an innovation scheme?** - **Are there any additional considerations that should be incorporated into an innovation scheme?** - **What level of allowance should be allowed under any proposed innovation scheme, and what type of innovation projects should be in scope?**	
Incentives	- Customers supported an opex EBSS in AA5. - Customers did not support an innovation or capex incentive scheme applying in AA5.	- At Shipper Roundtable 8 we further discussed an opex EBSS in more detail, including the design basis and an example of how the proposed scheme could work in practice.
	Stage 4 Engagement: Refining our Plans	
	- Customers sought assurance that the proposed scheme would include both rewards and penalties. Customers also wanted to understand the mechanics as to how the rewards and penalties are determined.	- We provided an example model to customers for their review and consideration. The proposed scheme includes both rewards and penalties.
	Final Plan Outcome	
	- Price is important to our customers and we have customer support for strengthening our incentives for efficient opex. - Our proposal to introduce an opex incentive scheme in AA5 is supported by customers and stakeholders. - We haven't included an innovation, capex or a customer incentive scheme in our proposal in AA5, as these were not supported by customers.	

Topic	Customer and Stakeholder Feedback	Our Response
Revenue and prices	**Stage 1 and 2 Engagement : Developing our Plans**	
	• Reliability and price are two of the most important considerations for customers and are often raised together. • Customers were keen to understand the price impact of our proposals.	• We provided information to customers during Shipper Roundtable Meetings 1 and 2 including an overview of how our prices are determined using the regulatory building blocks. • We also adopted an approach to cost allocation consistent with that accepted in AA4. • We adopted a transparent approach to informing customers of the price impacts of our proposals, including regular updates to the regulatory building blocks and resultant prices for almost 12 months prior to submission of our Final Plan. • Our Draft Plan presented customers with the building block revenue and price based on various assumptions and our proposals at the time. It included a $130 reduction in revenue, resulting in a price of $1.40 per GJ.
	Stage 3 Engagement : Draft Plan Consultation • **Have we provided enough information to understand the basis of our proposed price, including how it is split between the capacity and commodity components?** • **Is there anything that our Draft Plan hasn't considered that is important to you?**	
	• Customers requested further information on cost allocation between fixed and variable costs and between different services.	• We explained that Part and Back Haul prices are calculated using a distance factor of the Full Haul price. • We provided further explanation on our approach to adjusting the split between the capacity and commodity components of our price
	Stage 4 Engagement: Refining our Plans	
	• Customers wanted to be continually updated on our proposed price.	• We continued to provide building block and price updates to Shipper Roundtable members as we developed our Final Plan.
	Final Plan Outcome	
	• We have delivered a revenue reduction of $241 million. • Our Final Plan outlines further information on cost allocation and adopts an approach consistent with the approach accepted in AA4.	

6 Pipeline and Reference Services

The proposed pipeline and reference services for AA5 are consistent with those currently provided on the DBNGP.

IN THIS CHAPTER

- **We have followed new requirements for outlining pipeline and reference services**
- **Full haul, part haul and back haul services are proposed to continue as reference services for AA5**
- **These reference services are complemented by a suite of non-reference services**

We offer various pipeline services to meet the needs of our customers. Within the regulatory framework, we offer three reference services – full haul, part haul and back haul.

Our reference services are a subset of our pipeline services. They have been determined based on 'reference service factors',[4] which include factors such as actual demand for the service, the ability to reliably forecast demand for the service, substitutability with other services and the usefulness of the service in supporting access negotiations.

The reference services we propose for AA5 are consistent with those currently applied in AA4; full haul, part haul and back haul services. The reference services form the basis for this Final Plan.

The following sections outline the pipeline services and provide further detail on the three reference services we will provide to our customers.

An overview of the terms and conditions of our reference services is provided in Chapter 14 of this Final Plan with further details provided in the attachments to that chapter.

6.1 Regulatory framework

Recent changes to the NGR put in place a new approach to addressing pipeline services and reference services within and leading up to AA proposals.

Under transitional provisions included in the amendments to the NGR adopted in March 2019, a modified version of these rules applies to the DBNGP for AA5.[5]

Our Final Plan is required to:[6]

- describe all pipeline services provided on the DBNGP;
- specify which services are reference services having regard to the reference service factors; and
- describe any feedback from pipeline users and end users in identifying the reference services.[7]

6.2 Customer and stakeholder engagement

We engaged with our customers on our pipeline services and proposed reference services.

We discussed pipeline and reference services at the Shipper Roundtables and included the proposed reference services in our Draft Plan for further engagement.

Shippers valued the current reference services as the key

[4] NGR47A(15)
[5] NGR Schedule 1 Transitional Provisions, s 60
[6] NGR Schedule 1 Transitional Provisions, s 62(5)
[7] NGR Schedule 1 Transitional Provisions, s 60 "48(b), (c), (d)

services offered on the DBNGP and in support of negotiations.

Our shippers agreed it was appropriate to continue with the current three reference services in AA5. This was on the basis that the reference services continue to reflect the key services demanded on the DBNGP, noting other pipeline services reflect the bespoke requirements of certain shippers (which also have largely unpredictable demand, costs and revenue).

The potential for Inlet Sales to be included as a reference service was queried. It was however recognised that this service did not meet the reference service factors. Specifically, this service has close substitutes (in bilateral swaps) meaning we have little market power, limited basis to inform negotiations for other services and, a very small revenue of $0.4 million per year.

An updated list of our services is available at https://www.dbp.net.au/about-dbp/customer-access/

During our stakeholder engagement process we also provided customers with our proposed changes to the reference service terms and conditions. Our proposed changes are available in Attachment 14.1.

A summary of all customer and stakeholder feedback regarding pipeline services and how we have responded is summarised in Table 6.1.

6.3 Pipeline Services

Table 6.2 outlines the pipeline services to be offered in AA5 to current and prospective users on the DBNGP.

Table 6.2 also includes further information on the characteristics of different pipeline services,[8] specifically the service type, and receipt and delivery points (or inlet and outlet points as defined in the Terms and Conditions). More detail can be found in the terms and conditions for each service.

[8] NGR47A(2)

Table 6.1: Customer and stakeholder engagement: Pipeline and reference services

Topic	Customer and Stakeholder Feedback	Our Response
Pipeline and Reference Services	**Stage 1 and 2 Engagement : Developing our Plans**	
	Customers value transparency around the products and services that are available. Customers requested that additional detail related to services be included on the DBP website. Agreement that Reference Services should be consistent with those offered in AA4 (Shipper meetings 1 and 2).	• We provided information to customers during Shipper Roundtable Meetings 1 and 2 including an overview of current services, and definition of reference and non-reference services. • We updated the DBP website to include more information of all services provided to customers in March 2019. • We have proposed Full Haul, Part Haul and Back Haul Reference Services consistent with the current Reference Services, noting that we will continue to negotiate bespoke services with customers.
	Stage 3 Engagement : Draft Plan Consultation • **Do you think the Pipeline and Reference Services we have proposed are appropriate?**	

	Customers supported the proposed Full Haul, Part Haul and Back Haul Reference Services consistent with the current Reference Services.
	Customers requested information on the relative importance of reference services and non-reference services for our revenues.
	Customers requested that any potential changes to terms and conditions be identified.
		• At Shipper Roundtable Meeting 7, we provided further information to customers noting:
		  • The distinction between Reference Service Contracts and the Standard Shipper Contracts (SCC).
		  • That non-reference service revenue in the previous 3 years ranged from 2-5% of revenue and is highly variable year on year.
		• We provided customers with our proposed changes to Reference Service Terms and Conditions in November 2019, with comments provided prior to submission of the Final Plan.

	Stage 4 Engagement: Refining our Plans	
	Customers requested that a list of proposed amendments to the terms and conditions be circulated and discussed.	• On 15 November 2019 we circulated for consultation a table of proposed amendments and a mark-up of the Reference Service Terms and Conditions for T1, P1 and B1 Reference Services. We sought feedback by 2 December, however we noted the tight timeline and offered to continue to engage with shippers through the new year.
	Final Plan Outcome	
	• Our proposal provides transparency around the services we provide, which are valued by our customers. • Our proposal for Full Haul, Part Haul and Back Haul Reference Services is consistent with the current Reference Services and is supported by customers and stakeholders.	

Table 6.2: Pipeline services

Pipeline service name	Service type	Category of service
Full Haul T1 Service	Forward Full Haul (subject to available capacity) with outlet point south of CS9, regardless of the location of inlet point	Reference
Part Haul P1 Service	Forward Part Haul (subject to available capacity) with outlet point upstream of CS9, regardless of the location of inlet point	Reference
Back Haul B1 Service	Back Haul (subject to available capacity) service where the inlet point is downstream of the outlet point.	Reference
Seasonal service	A gas transportation service where the profile of reserved capacity can be customised to suit the monthly requirement of the Shipper (subject to available capacity)	NA – not a stand-alone service
Metering and temperature service	A pipeline service where particular metering and temperature specifications can be set (subject to available capacity)	NA – not a stand-alone service
Odorisation service	A pipeline service where particular odorant requirement can be specified (subject to available capacity)	NA – not a stand-alone service
Pilbara service	The Pilbara Service is an interruptible transportation service on the DBNGP where deliveries are within the Pilbara Zone (subject to available capacity)	Non-reference
Spot capacity service	Allows access to gas transmission capacity on a day ahead basis where available via auction (subject to available capacity)	Non-reference
Peaking service	A pipeline service where a shipper can obtain additional peaking limits to those set in standard terms (subject to operational availability)	Non-reference
Pipeline impact agreement (PIA)	An agreement specified under the *Gas Supply (Gas Quality Specifications) Act 2009* developed to compensate PIA Pipelines (including AGIG) for costs incurred when producers wish to bring broader quality gas into the relevant pipeline.	Non-reference
Inlet sales agreement	A pipeline service that facilitates the trading of gas between shippers at a single inlet point on the DBNGP (subject to operational availability)	Non-reference
Data services	A service developed to assist gas marketers providing gas allocations on Shippers' behalf on the DBNGP (subject to operational availability)	Non-reference
Storage service	A service designed to allow shippers to store gas in the pipeline. Forecast to decline substantially due to rise of competitive storage market (Tubridgi and Mondarra)	Non-reference
Other reserved service	A suite of interruptible services offered on a bespoke basis to shippers with new projects and/or uncertain demand, often ahead of a firm service	Non-reference

6.4 Reference services

We are proposing to offer three reference services in the AA5 period, consistent with those in AA4. These are:

- Full Haul T1 Service
- Part Haul P1 Service
- Back Haul B1 Service.

Our pipeline services have been assessed against the reference service factors[9] in Attachment 6.1. The reference service factors are:

- actual and forecast demand for the pipeline service and the number of prospective users of the service;
- the extent to which the pipeline service is substitutable with another pipeline service specified as a reference service;
- the feasibility of allocating costs to the pipeline service;
- the usefulness of specifying the pipeline service as a reference service in supporting access negotiations and dispute resolution for other pipeline services; and
- the likely regulatory cost.

The three reference services proposed have been assessed against the reference service factors as follows:

- they are in high demand;
- they are non-substitutable with other services (meaning there is no other way shippers can obtain the service);
- they form the foundation of our demand forecasts and cost allocation;
- they provide prospective users with an aid for use in access negotiations; and
- they minimise the cost and regulatory burden.

We do not consider the remaining pipeline services are appropriate to specify as reference services having regard to the reference service factors for a range of reasons, including the following issues which vary across each service:

- varying degrees of demand and revenue forecastability;
- high substitutability with reference services where the pricing applied to reference services provides an appropriate basis on which to consider the reasonableness of prices for non-reference services (eg, using the Part Haul reference service to understand the Pilbara service);
- costs which are in general separable from the costs of providing reference services and thus not included in the cost base which makes up our regulatory services;
- minimal usefulness as an aid to negotiations for other services because the service is unique and does not provide a useful benchmark in considering the reasonableness of other services; and
- impose a high regulatory cost-burden relative to the share of the service in our revenue, specifically where revenues generated are small relative to the likely regulatory costs.

The remaining pipeline services are therefore considered non-reference services. The vast majority (around 97%) of our revenues continue to be derived from services with a reference tariff and terms and conditions to form the basis of negotiations.

More detail on our assessment of the reference service factors is included in Attachment 6.1.

6.5 Summary

We propose that the Reference Services for the DBNGP in the AA5 period remain consistent with those applied in AA4. In response to our engagement program, customers confirmed the three reference services remain appropriate when considered against the reference service factors.

Our AA5 plans have therefore been underpinned by providing the:

- Full Haul T1 Service (T1 Service);
- Part Haul P1 Service (P1 Service); and
- Back Haul B1 Service (B1 Service).

We also continue to offer other pipeline services and invite any current and prospective shipper to discuss their specific requirements with our commercial team, as currently occurs.

In response to shipper requests for more information on all of the services we offer we have provided a full list of our services in Table 6.2 above, and also on our website.

[9] NGR47A(15)

7 Operating expenditure

IN THIS CHAPTER

Real opex reduction of 4% compared to actual opex incurred in AA4

Maintaining the safe, reliable and high-quality service our customers value

Lower system use gas costs

Since becoming part of AGIG, we have been able to embed operating expenditure (opex) savings at DBP that will be passed on to our customers in AA5, along with lower system use gas costs.

We incur opex to undertake activities that allow us to operate and maintain the DBNGP safely, reliably and efficiently. Opex also underpins our customer service.

Consistent with our objective of a plan capable of acceptance, we have adopted an approach to forecasting opex in line with that applied by the ERA for AA4 and the other businesses it regulates.

The forecast comprises a base-step-trend approach for recurrent expenditure as well as specific bottom up forecasts of expenditure, such as for System Use Gas (SUG), where this would reflect a more reasonable estimate of our efficient costs for AA5.

The following sections outline this approach, key drivers of expenditure and the outcomes we will deliver in AA5. In addition, this chapter outlines how we ensure the opex we incur is efficient, and how we have performed in AA4. All numbers quoted are dollars of December 2020, unless otherwise labelled.

The opex in this chapter is supported by a number of attachments that provide further information to demonstrate it satisfies the criteria of rule 91, including:

- a reconciliation of the actual opex for 2016 to 2018 with statutory accounts (Attachment 3.1); and
- Business Cases for the bottom-up forecast items, which have been provided in Attachment 7.2.

For opex that is forecast by adopting a base-step-trend approach, we have included information in this chapter to demonstrate the efficiency of our base year, including our opex performance overtime, and our performance in the current period compared to our allowances.

7.1 Regulatory framework

The NGR, and specifically rule 91, require that our forecast opex must reflect that incurred by a prudent gas pipeline business, acting efficiently and in accordance with good industry practice to achieve the lowest sustainable cost of providing reference services to our customers.

7.2 Overview

Our forecast opex including SUG for AA5 is $458 million over the five years. This is a reduction of $20 million (4%) compared to our actual performance over the AA4 period of $477 million (forecast to December 2020).

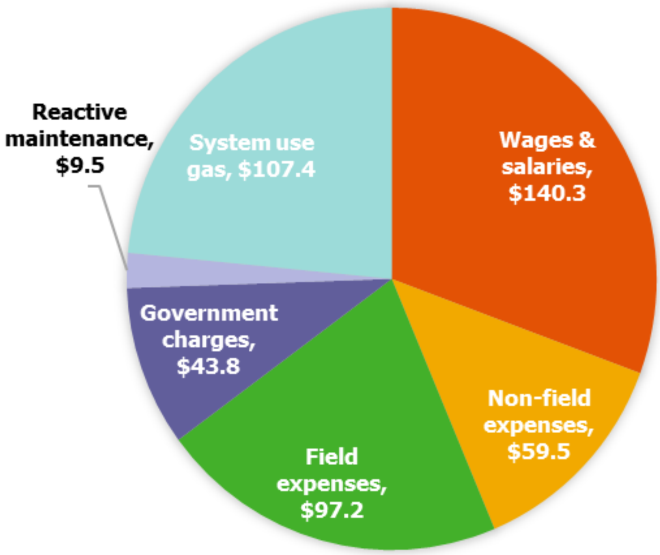
This reduction is largely driven by forecast lower SUG costs and our ability to keep other opex at similar levels to those achieved in the current period. It also builds on our outperformance of our allowances in AA4.

Since our Draft Plan, we have made a number of refinements and updates to our opex forecast, which increased by $20 million (4%) compared to our Draft Plan. The key drivers of this change are:

- updating our base year for nine months of actuals through to the end of September 2019 and other factors (increase of $20 million);
- refining our cost estimates and AA5 activities for mandatory asset inspections (increase of $4 million);
- changes in throughput which flow through to our forecast SUG and turbine and GEA overhauls (decrease of $4 million).

Our total AA5 opex by category is shown in Figure 7.1. We step through each of the elements of our opex forecast in sections 7.5, 7.6 and 7.7.

Figure 7.1: Forecast AA5 Opex by category, $December 2020



7.3 Customer and stakeholder engagement

We engaged with customers and stakeholders on the development of our opex proposal.

Customers highly value the current levels of reliability of service they receive, and it is important that this is maintained.

Customers were keen to understand and ensure that our costs are prudent and efficient, and that there is transparency around how our expenditure compares to previous years and where changes have occurred. This chapter and attachments demonstrates how we are cost efficient in our operations.

A summary of all customer and stakeholder feedback regarding opex and how we have responded is summarised in Table 7.1.

Customers are comfortable with our approach to forecasting opex, noting consistency with past practice, and the level of opex we are proposing.

Our opex proposal:

- is consistent with the ERA's preferred forecasting methodology;
- is responsive to customer needs for a continued focus on operational issues, which is important for safety, reliability and emergency management; and
- provides supporting information required and evidence that we are cost efficient, specifically Attachments 7.1, 7.2 and 7.3.

Table 7.1: Customer and stakeholder engagement: operating expenditure

Topic	Customer and Stakeholder Feedback	Our Response
	Stage 1 and 2 Engagement : Developing our Plans	

Operating expenditure	• Customers highly value current levels of safety and reliability.
	• Customers are keen to ensure opex is efficient.
	• Maintaining a strong focus on operational issues is important for reliability and emergency management.
	• Customers requested clear visibility of changes in forecast opex between AA4 and AA5.
	• Customers requested additional information relating to the proposed 94/6 split between fixed and variable opex costs.
	• Customers queried the opex of turbines and GEAs.
		• We prepared draft opex proposals focused on maintaining current levels of system reliability.
		• We provided information to customers on the cost categories that are increasing in AA5 and included this in our Draft Plan for comment, and in this Final Plan.
		• At Shipper Roundtables 3 and 4 we provided detailed information regarding turbines and GEAs, including:
		  ◦ the treatment of turbines and GEA overhauls as opex, rather than capex;
		  ◦ the cost split between turbines and GEA overhauls;
		  ◦ the DBNGP operating profile including run hours, maintenance schedule and activities to ensure efficient operation, noting critical stations and the impact of stop-start costs and other network impacts on overhauls.
		• We provided supporting information in our Draft Plan, and have included this information in our Final Plan, as requested by customers relating to how our spend compared to previous years, and where there had been areas of change (e.g scheduling of overhauls).

	Stage 3 Engagement : Draft Plan Consultation • **Do you support our approach to forecasting opex?** • **Is there sufficient information to understand our proposals and the basis of the costs included?**	

	• Customers were interested in more detail regarding the derivation of costs.
	• Customers wanted further transparency on the difference between opex and capex activities relating to turbines and GEAs.
	• Customers want to ensure that costs are efficient and questioned whether there should be benchmarking costs against similar pipeline businesses.
	• Customers would like to see trends in fuel efficiency over previous AA periods.
		• At Shipper Roundtable 7, we explained the supporting information that is included in the Final Plan including assurance of actual spend in the current period, and project and program business cases and supporting models (Attachment 7.2). Customers agreed that this was sufficient information.
		• We discussed efficiency and benchmarking with customers at Shipper Roundtable 7 and 8 including:
		  ◦ a presentation of data illustrating that opex per unit of total energy delivered and opex per km has reduced over time;
		  ◦ highlighting that while we value benchmarking, sourcing benchmarking data for transmission pipelines is challenging, particularly given the uniqueness of the DBNGP.

Topic	Customer and Stakeholder Feedback	Our Response
Operating Expenditure	**Stage 4 Engagement: Refining our Plans**	
	Customers requested more information in relation to the change in forecast opex from AA4 actual to AA5.	• We provided additional information at Shipper Roundtable 8, highlighting that the key driver behind the $27 million increase period-on-period is the change in capitalisation policy (approximately $12 million) to better reflect the nature of these costs. We have provided independent advice that this is reasonable under accounting principles in this Final Plan (see Attachment 7.4).
	Final Plan Outcome	
	• Our opex proposal delivers against customer expectations that current levels of safety and reliability are maintained. • Our opex proposal is responsive to customer needs for a strong focus on operational issues, which is important for reliability and emergency management. • Our Final Plan provides required supporting information on opex, and evidence that we are cost efficient, specifically Attachments 7.1, 7.2, 7.3 and 7.4. • Customers are comfortable with our approach to forecasting opex., noting it is consistent with the ERA's preferred methodology.	

7.4 Our opex over time

Figure 7.2 shows our opex performance, excluding SUG, over AA4 and AA5. It shows we have been able to reduce our opex compared to our approved allowances in AA4 and will pass this on to our customers in AA5. We have reduced our costs while continuing to provide the same levels of safety, reliability and service performance to our customers.

Figure 7.3 shows our SUG costs over AA4 and AA5, as well as our fuel gas efficiency (fuel gas being the largest component of our SUG requirements). We are expecting lower SUG costs in AA5 as a result of lower forecast gas prices.

7.5 How we develop our opex forecast

There are two different methods we use to forecast our opex over AA5.

Firstly, for most opex categories, we apply a base-step-trend approach.

Secondly, for SUG, turbine and gas engine alternator (GEA) overhauls, we determine specific forecasts for AA5 as the variability in costs

Figure 7.2: AA4 and AA5 opex excluding SUG

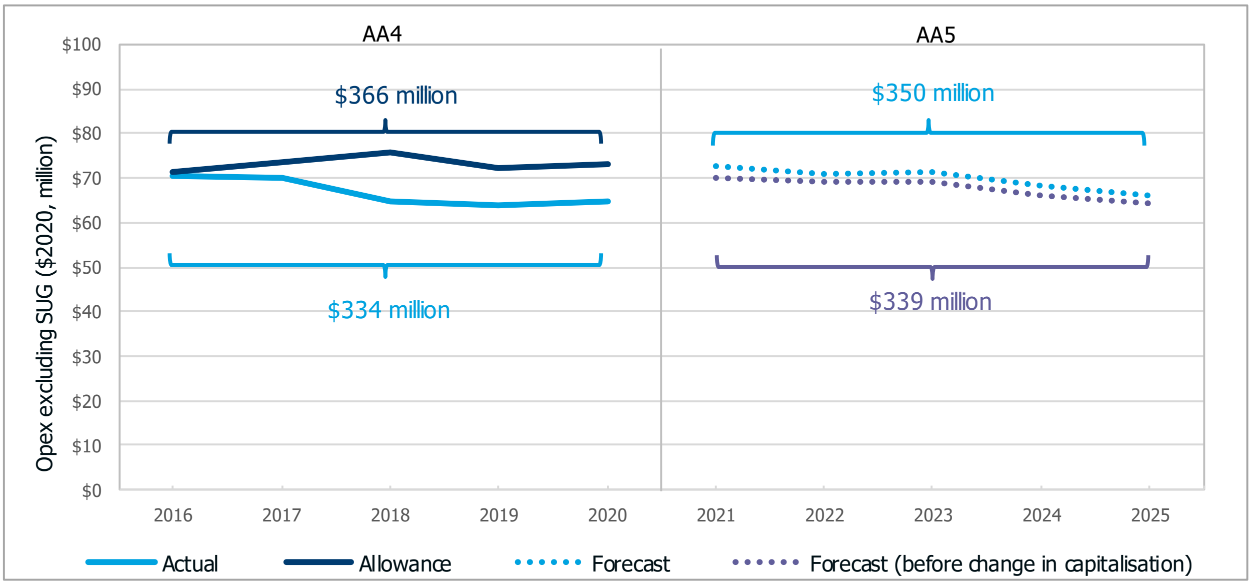
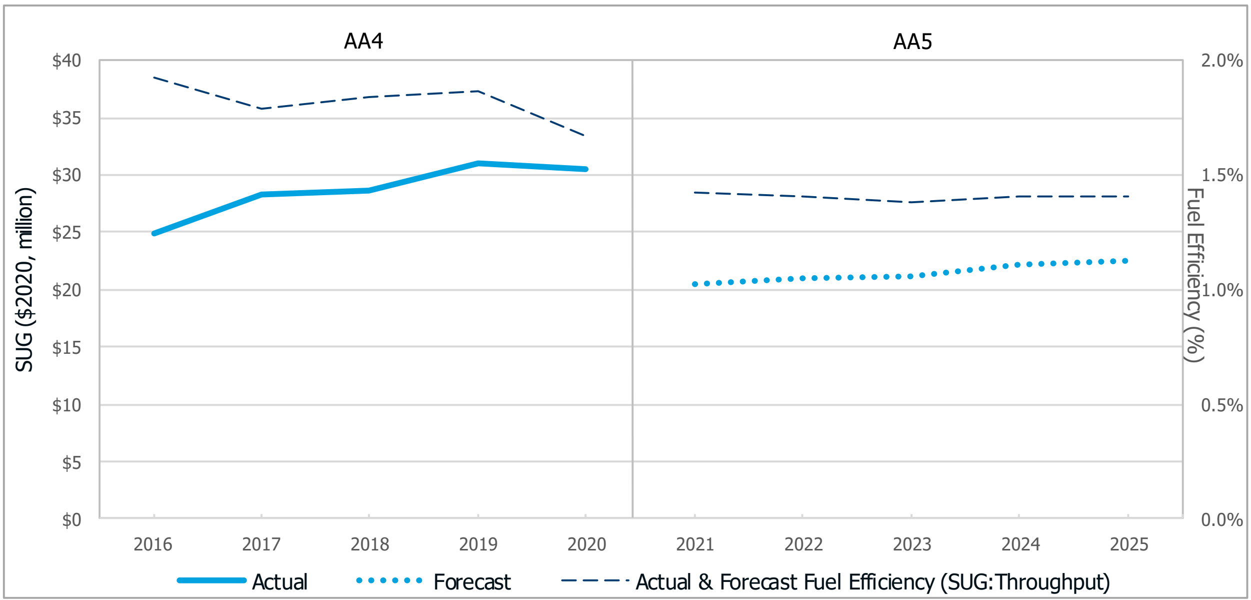


Figure 7.3: AA4 and AA5 System use gas costs



between periods does not lend itself to the base-step-trend approach.

Additionally, we are proposing that asset inspections, other minor pipeline works and small health and process safety initiatives be treated as opex in AA5 as the expenditure is more operating in nature.

Independent advice in support of the re-classification away from capex is included in Attachment 7.4, while derivation of the expected expenditure for each of the activities are contained in Attachment 7.1 to 7.3.

This methodology is consistent with the ERA's preferred forecasting method applied in AA4 and for its other regulated businesses, and as such, is consistent with achieving our objective of submitting a plan that is capable of being accepted.

7.6 Key drivers in AA5

We will maintain our strong safety, reliability and customer service performance, within our lower opex forecasts in AA5.

7.6.1 Delivering for customers

Our opex proposal is designed to allow us to undertake asset maintenance as required by our asset management plans, and activities to maintain our strong safety, reliability and customer service performance.

7.6.2 A good employer

Our opex proposal will help us continue to provide a healthy, safe, engaged and skilled workforce. Our non-field expenses include ongoing workplace health and safety programs, while field expenses include employee and contractor training and development initiatives.

7.6.3 Sustainably cost efficient

Our opex proposal shows we are sustainably cost efficient as we have:

- delivered real opex savings of around $21 million per annum compared to our approved allowances for AA4; and
- kept our opex excluding SUG in AA5 at similar levels to that incurred in AA4, despite facing a number of upward cost pressures in IT support, field expenses, and input cost changes along with the additional costs relating to the change in capitalisation.

7.7 Our AA5 opex forecast

The following sections step through each of the elements of our AA5 opex forecast.

7.7.1 2019 base year

We are proposing calendar year 2019 as our base year for forecasting our AA5 opex. 2019 is the penultimate year of the current AA period.

This is consistent with regulatory practice across Australia. This is because the penultimate year reflects the most recent actual information before the ERA's final decision.

We have included a forecast for 2019 opex. This includes nine months of actuals and three months of forecasts.

By the time the ERA makes its Draft Decision, we will be able to provide a full year of actuals for our 2019 base year.

We are proposing the same opex categories as used in AA4. These are:

- wages and salaries;
- non-field expenses;
- field expenses;
- government charges;
- SUG; and
- reactive maintenance.

We are confident our 2019 base year opex is prudent and efficient because it has been estimated based on most recent actuals and on verified records of actual opex over 2016-2018, with variances compared to 2018 having been tested through our internal budgeting processes.

7.7.2 Adjustments to base year opex

We make adjustments to our base year opex in those cases where it is not reflective of recurrent costs likely to be incurred in a typical year.

Specifically, we take a five-year average of our consulting and reactive maintenance costs, rather than the 2019 base year, due to some volatility that can be experienced in these cost categories year to year. This is consistent with the approach approved by the ERA in AA4.

Furthermore, we have taken a rolling six-year average of our insurance costs, rather than the 2019 base year, due to the cyclical nature of insurance markets. This is also consistent with the approach approved by the ERA in AA4.

As stated earlier, adopting approaches that align with those previously approved by the ERA is consistent with achieving our objective of submitting a plan that is capable of being accepted.

7.7.3 Opex step changes

We make adjustments to our AA5 opex for any step changes in our costs resulting from changes in legislation, regulatory obligations or new activities.

In our Draft Plan, we proposed to increase our opex in AA5 by $10,000 per annum to cover the increased cost of purchasing the data required to calculate our annual cost of debt updates in line with the ERA's *Final Rate of Return Guidelines 2018*. For our Final Plan, we have withdrawn this proposal and absorbed this cost within our existing opex levels.

Consistent with the Draft Plan, we have decided not to increase our IT opex in AA5, despite estimating a step change requirement of around $8 million (mainly in increased managed services costs) resulting from the increased IT investment we are proposing in AA5 to improve our business intelligence, data management and digital capabilities.

We took this approach because we believed these higher IT operating costs may be offset by reduced opex in other areas of the business, driven specifically by our IT enabling initiatives. Further this also provides a clear incentive on us to ensure that the benefits we estimate these programs can deliver are realised and passed through to customers.

7.7.4 Input cost escalation

We make adjustments to our base year opex to account for costs that are increasing at a faster rate than inflation (real cost escalation).

When considering real cost escalation, opex costs are typically split into two categories; labour and materials. We have applied the approach used by the ERA in recent decisions, which is to reflect the business's actual split of opex costs.

Labour cost escalation

For this Final Plan we have applied real cost escalation of 0.69% per annum to our labour costs based on the latest data available at the end of October 2019. This is 1.23% lower than the 1.92% per annum applied in our Draft Plan, which is primarily driven by incorporating the ERA's approach in its Draft and Final Decisions for ATCO Gas and the Goldfields Gas Pipeline (GGP).

Historically, a premium has been applied to real wage price growth to account for the typically higher wage growth in the Electricity, Gas, Water and Wastewater Services (EGWWS) industry compared to the average wage growth for all industries.

We consider this premium is appropriate as it reflects actual empirical observations. However, we note the ERA has considered this issue in its recent decisions for ATCO Gas and GGP,[10] and has concluded such a premium is not appropriate. Consistent with our objective of submitting a plan capable of acceptance, we have therefore not included this premium when determining the real labour cost escalation to apply to our forecasts for AA5.

Therefore, we have calculated the appropriate labour cost escalation by:

- taking the Western Australian Treasury Wage Price Index (WPI) forecasts for the upcoming period; *less*
- the Western Australian Treasury inflation estimate embedded in its WPI forecasts for the upcoming period.

Table 7.2 provides the values used in this calculation.

Table 7.2: Annual labour cost escalation estimate for AA5

Measure	Value
WA Treasury WPI forecast	3.15%
less WA Treasury Inflation forecast	2.46%
Annual labour cost escalation	**0.69%**

[10] See https://www.erawa.com.au/cproot/20818/2/GDS---ATCO---AA5---Final-Decision---Public-FINAL-Version.PDF and https://www.erawa.com.au/cproot/20818/2/GDS---ATCO---AA5---Final-Decision---Public-FINAL-Version.PDF

We have taken this approach having regard to:

- the approach applied by the ERA in its most recent decisions whereby the Western Australian Treasury estimate of inflation (rather than the ERA's benchmark estimate of inflation) is subtracted from the Western Australian Treasury WPI; and
- that while we have not applied an explicit productivity growth adjustment to our opex in AA5, we have proposed to absorb estimated IT opex step changes of around $8 million, which results in an implied annual productivity of around 0.6% per annum (this is discussed further below).

Our approach to labour cost escalation, including productivity, is consistent with the ERA's recent decisions.

We also note our decision to not apply a productivity factor is consistent with the ERA's recent decisions for ATCO Gas and GGP.[11]

Materials cost escalation

For this Final Plan we have applied 0% real cost escalation per annum to our materials costs. This is consistent with our approach in our Draft Plan, and also with recent regulatory decisions for gas and electricity service providers in Australia.

7.7.5 Output growth

We are not proposing to apply an output growth factor to our base-step-trend opex. Two of our key costs, SUG and overhauls, vary with throughput and are already forecast using a unit cost and volume methodology. Therefore, these costs are already linked to the level of forecast throughput.

7.7.6 System use gas

We are forecasting $107 million in SUG costs in AA5. This is a significant reduction compared to the SUG costs we are incurring in AA4. The reduction is mainly driven by lower gas prices compared to when we last tendered for our SUG requirements in 2014.

As mentioned in Section 7.5, our SUG costs are a function of forecast quantity and forecast price.

The forecast quantity of SUG is driven by expected gas quality, the quantity required as compressor fuel to transport forecast throughput and the quantity required for all other operational activities including in GEAs and heaters, and vented during normal operation and maintenance activities.

We have adopted the same quantity calculation that was approved in AA4. The ERA and its expert consultant considered this was reasonable as:

- the gas quantity calculation was based on an industry standard model;
- the model was calibrated using actual pipeline operation information;
- adjustment factors in the model were derived from operating experience around average heating values and pressure at receipt points; and
- the modelled relationship between fuel, throughput and other operating conditions was almost identical to the actual relationship, which indicated a valid model and valid input assumptions.

Our forecast throughput for AA5 is outlined in Chapter 11. Our forecast price for SUG is based on the weighted average price that we will achieve across our SUG supply contracts secured in the market. This is consistent with the ERA's approach in AA4 to adopt the weighted average price of our two SUG contracts.

Again, we have applied the most recent ERA approach to determine SUG costs consistent with our objective to develop a Final Plan capable of acceptance.

Our SUG performance in AA4 is discussed at 7.9.

7.7.7 Turbine and GEA overhauls

We are forecasting $31 million in turbine and GEA overhauls in AA5. This is $8 million less than the forecast in our Draft Plan in May 2019 due to updated throughput and utilisation assumptions. The latest throughput information we have received from our Shippers results in slightly fewer run hours than assumed in our Draft Plan, indicating one of the previously forecast turbine overhauls for AA5 can be delayed until AA6.

As mentioned in Section 7.5, our turbine and GEA overhaul costs are a function of unit run hours and estimated cost per unit.

The following provides a summary of each of the turbine and GEA overhauls forecast in AA5. More detail on this program of work, its drivers and how it compares to what has been delivered in the current period can be found in the Gas

[11] See https://www.erawa.com.au/cproot/20818/2/GDS---ATCO---AA5---Final-Decision---Public-FINAL-Version.PDF and https://www.erawa.com.au/cproot/20818/2/GDS---ATCO---AA5---Final-Decision---Public-FINAL-Version.PDF

Turbine and GEA Overhauls Business Case at Attachment 7.2.

Turbine overhauls

Our replacement strategy for our turbine units is to overhaul them after 30,000 run hours in line with manufacturer specifications. After 30,000 run hours, the likelihood and cost of failure of turbine units increases significantly, by around 1.5 times. As our turbines are integral to the safe and reliable delivery of our services, and because there can be long lead times in ordering parts, our turbine overhauls must be carefully planned.

Based on current run hours and utilisation rates for turbine units we are forecasting to overhaul seven units in AA5. In the event of a premature failure (outside of expectations in our AMP and manufacturers' guidance), we have also allowed for an overhaul of one additional turbine unit during AA5. We estimate two overhauls each year for the first three years of the period, with one each in the last two years at an average cost of $6 million per annum.

This compares to six turbine overhauls, two premature failures and two turbine swaps in AA4 at a total cost of $24 million (forecast to 31 December 2020). The lower expenditure in the current period is a result of managing both turbines at each compressor station to spread run hours and keep units below the operational hour level of 30,000 hours that acts as the key criteria in identifying an asset for overhaul (replacement) for longer.

This approach was adopted in response to changing business needs in other programs of work over AA4 (many of which are summarised in our discussion of capex in Chapter 8).

Figure 7.7.4: Turbine exchange, Compressor Station 2, Unit 3, September 2018

This approach cannot be adopted indefinitely, as more turbines approach the operational hours ceiling in line with manufacturer specifications; hence the small increase in the number of overhauls for AA5 even though throughput is forecast to fall slightly.

GEA overhauls

GEAs are the primary source of electricity at many of our remote facilities, including all compressor stations north of Perth.

Our GEAs are serviced regularly, with major services (overhauls) required at 12,000, 24,000, 48,000 and 52,000 hours.

Based on current run hours and utilisation we are forecasting 20 GEA overhauls in AA5, spread relatively evenly across the period, at an average cost of $1 million per annum.

This compares to 16 GEA overhauls in AA4 at a total cost of $4 million (forecast to 31 December 2020).

The run hours of GEAs are driven by the power demands at each site. Given the base load power requirements, the slight fall in throughput does not materially change the run hours nor the number of overhauls forecast for AA5.

7.7.8 Change in capitalisation

We have included $11 million of asset inspections, other minor pipeline works, health and process safety initiatives as opex from AA5. This is $4 million more than the $7 million proposed in our Draft Plan as a result of refining our cost estimates and the scope of the activities required.

While these activities have previously been treated as capex, we propose they are better aligned to opex. Similar activities undertaken across our distribution networks, and by other pipelines and electricity networks, are treated as opex. We also sought expert advice to confirm this treatment is appropriate, which is available at Attachment 7.4. The report concluded that:[12]

"the forecast expenditure by DBP as part of undertaking all of these activities and programs in the next access arrangement…meets the definition of an expense."

This change has no impact on totex (the sum of opex and capex) in AA5.

More detail on these programs of work, the drivers and how the forecast expenditure and activities compare to what has been delivered in the current period can be found in the following Business Cases included in Attachment 7.2:

- Asset Management;
- Decommissioning;
- Health, Safety and Environment;
- Pipeline and MLV Inspections;
- Process Safety; and
- Station Inspections.

7.8 How we ensure the opex we incur is prudent and efficient

We operate within a framework of external and internal controls which govern the way we fund the day-to-day operations of our business. This framework ensures we are making sound decisions for our customers, our stakeholders and our business.

7.8.1 Our Safety Case, Asset Management Plan and maintenance regime

The *Petroleum Pipelines Act 1969* (WA) requires that we submit a Safety Case to the Department of Mines, Industry Regulation and Safety every five years for approval.

The Safety Case (Attachment 8.3) outlines how we operate the DBNGP in compliance with our obligations under the Act, Regulations and operating licences. It demonstrates the adequacy of the systems, processes and procedures in place to support the safe operation of the DBNGP.

The Safety Case also describes the hazards associated with operations, and the controls in place to manage hazards to a level that is as low as reasonably practical (ALARP). The maintenance requirements set out in our Asset Management Plan (AMP, Attachments 8.1 and 8.2) ensure these controls remain available, reliable and effective. Therefore, our AMP is a key part of our demonstration in the Safety Case of our ability to control the risks of our operations to ALARP.

Our overarching AMP considers the relationships between asset life/performance, economic returns, operating costs, safety and reliability all within the context of our short, medium and long-term business strategy. Individual AMPs consider these issues for specific asset classes.

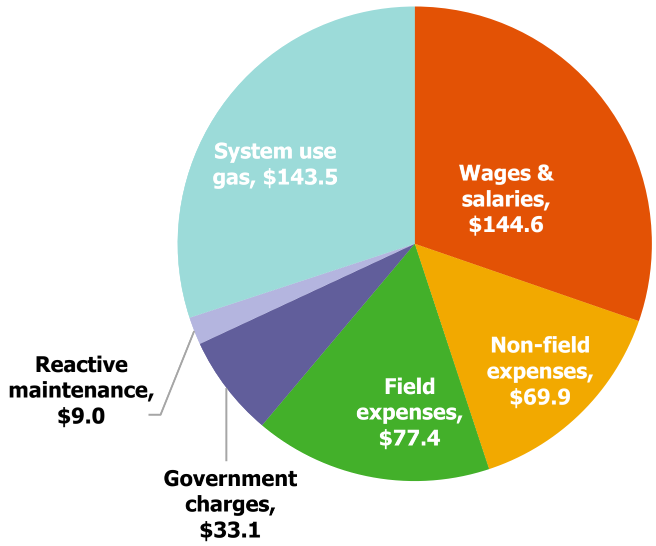
With regard to operational activities, the AMPs sets out the asset maintenance regime applied to the DBNGP.

The maintenance regime has been developed over time incorporating regulatory requirements, risk assessment outcomes, substantial operating experience, good industry practice and lessons learned from others.

More specifically, the maintenance regime for identified maintenance tasks outlines the purpose, failure impact, priority, frequency or condition, required tools, spares and consumables, estimated duration and required labour hours by skill, as well as any preconditions such as isolation or availability of alternate

[12] *Dampier to Bunbury Pipeline – Regulatory Cost Allocation Review'* BDO Advisory (SA) Pty Ltd, Page 6

Figure 7.5: AA4 Opex by category, $December 2020



equipment. Each maintenance regime drives planning for the execution of maintenance tasks to minimise the impact of maintenance activities on the safe, efficient and reliable delivery of gas.

We periodically review and update our AMPs to ensure our maintenance strategies evolve or are amended in response to investigations of equipment failures.

Work instructions for each maintenance activity and asset type ensure the required work is carried out in line with our AMP requirements and safe work practices.

We also have several procedures, guidelines, plans and performance targets which govern the way we operate the DBNGP day to day. These ensure we undertake all operating activities in a prudent and efficient manner, consistent with good industry practice and in line with our vision of being the leading gas infrastructure business in Australia.

7.8.2 Financial governance

We regularly report our forecast and actual opex through our internal performance reporting. Our performance against prior year spend and approved regulatory allowances is reviewed, particularly where there are variances or costs are increasing.

Furthermore, our corporate KPIs track our safety, reliability, customer service and financial performance. These performance measures incentivise us to continually seek out ways to meet or exceed our targets, without favouring one area over another (i.e. reporting against all of these measures means we cannot make financial savings to the detriment of safety, reliability or customer service).

We also have strict procurement processes, which apply to both opex and capex. Our procurement process is described in Chapter 8, Section 8.7.3.

7.8.3 Internal Audit

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

Each year the Board approves an Internal Audit Plan. Independent external professional firms are engaged to deliver the audit reviews. Audit review outcomes, and any required actions, are presented to and agreed by the Audit Committee. This provides our directors and management assurance as to the existence and strength of the controls implemented.

During the 2016-19 period, the procurement for opex and payment processes was reviewed. Improvements implemented in response to this review included:

- strengthening vendor evaluations and approval of preferred Vendors;
- improved management of our contracts database;
- improvements in competitive tendering processes (independent mailbox and clarity around required documentation);
- strengthening controls within the Maximo procurement management system; and
- introducing additional measures to enhance controls over payment file encryption, vendor master file access control and maintenance, corporate credit card reconciliations and accounts payable balance review.

7.9 Our performance in AA4

We estimate our opex in AA4 excluding SUG will be $334 million, which is $32 million (9%) below our approved allowance for AA4.

Our total AA4 SUG costs are expected to be $46 million (24%)

below our allowance of $190 million. As already described, our SUG costs are a function of quantity required and price. The drivers for lower SUG costs than expected in AA4 have been:

- lower Full Haul throughput than forecast, which reduces the quantity of SUG required (as well as the revenue we receive from commodity, or throughput, charges); and
- the average price of SUG incurred (which is mostly related to timing differences in the way we expense SUG compared to what was assumed in our SUG forecast).

Our turbine and GEA overhauls (which make up a component of our field expenses) are $8 million (25%) below our allowance of $33 million as a result of lower Full Haul throughput than forecast (which reduces the run hours required across our fleet of turbines and gas engines, and therefore extends the time taken to reach the defined run hour parameters for overhaul).

Our wages and salaries are forecast to be $22 million (14%) below our allowance and our non-field expenses are $20 million (25%) below our allowance, reflecting efficiencies made in coming together as AGIG. Our Government charges are $4 million (18%) above our allowance and our reactive maintenance is $4 million (38%) above our allowance.

7.10 Key opex drivers in AA4

Our opex in AA4 is supporting our vision of:

- delivering for customers;
- being a good employer; and
- being sustainably cost efficient.

7.10.1 Delivering for customers

We have undertaken field works, asset maintenance and customer service activities in AA4 to ensure we maintain the strong safety, reliability and service performance our customers have told us they value.

7.10.2 A good employer

In AA4 we have undertaken health and safety programs and employee and contractor training to ensure we have a healthy, safe, engaged and skilled workforce.

We have maintained a TRIFR of zero for the last twelve months and not had any recordable injuries for 24 months.

7.10.3 Sustainably cost efficient

In AA4 we will deliver around $6 million of annual opex savings, which we will pass on to our customers through lower prices in AA5. This reduction is due to a combination of lower opex costs and an increase in total energy delivered, particularly for part haul and back haul services, between AA3 and AA4.

7.12 Summary

The key aspects of our opex forecasting methodology are outlined below.

- We have adopted the same opex categories as used in AA4.
- We have applied a base-step-trend approach for most categories of opex, with 2019 as the base year.
- Our estimate of 2019 comprises 9 months of actual to September 2019 and 3 months of forecast, Full year actual opex for 2019 will be provided to the ERA once it becomes available, expected prior to the ERA's draft decision.
- We have reduced our base year to use multiple year averages of consulting, reactive maintenance and insurance costs given the potential for volatility or cyclical movements in these costs year to year, consistent with the approved approach in AA4.
- We have not proposed any step changes, including for increases in IT opex resulting from our IT capex program (rather we propose to absorb these additional costs).
- Real cost escalation of 0.69% per annum has been applied to labour costs and the real cost escalation methodology applied by the ERA for the most recent ATCO Gas and GGP Final Decisions.
- We forecast significantly lower SUG costs mainly as a result of the lower weighted average price we expect to achieve across our SUG supply contracts compared to AA4.
- Turbine and GEA overhauls averaging $6 million per annum based on unit run hours and estimated unit costs per overhaul.
- Asset inspections, other minor pipeline works and small health and process safety initiatives (totalling $11 million) are more operating in nature, and we therefore propose this expenditure be treated as opex instead of capex from the commencement of AA5.

We believe our approach to forecasting opex incorporates feedback from our customers and stakeholders and reflects the ERA's preferred approach wherever possible. We therefore consider that our approach to forecasting opex is consistent with meeting our objective of providing a plan that is capable of being accepted by our stakeholders and the regulator.


ASTARIGLAS
CAST ACRYLIC SHEET

8 Capital expenditure

We are investing $160 million on the DBNGP over AA5. Our proposed capex will ensure we maintain our strong safety, reliability and service performance in AA5.

IN THIS CHAPTER

We are investing $160 million on the DBNGP to ensure we continue to provide a safe and reliable supply of natural gas to our customers

Key projects include northern communications, control systems and IT investments

We have invested $122 million on the DBNGP in AA4 including in southern communications and pigging.

We incur capex to ensure the ongoing safe and reliable supply of natural gas to Western Australian industry, businesses and homes every day.

Our bottom-up approach to forecasting capex for AA5 is consistent with our approach in previous periods, with an emphasis on the requirements of our Safety Case, Asset Management Plans (AMP) and risk management framework.

The following sections outline our approach and key drivers in forecasting capex, as well as the outcomes we will deliver over 2021-25. In this chapter we also outline how we are ensuring the delivery of our capex program efficiently and how we have performed in AA4.

Our capex plans are supported by detailed business cases, which have been provided in Attachment 8.5. These business cases describe how our capital program delivered in AA4 and planned for AA5 is prudent and efficient.

All dollar values quoted are dollars of December 2020, unless otherwise labelled.

8.1 Regulatory framework

Rule 79 of the NGR sets out the criteria for new capex. Under this rule, our forecast capex must reflect that required by a prudent transmission pipeline business, acting efficiently and in accordance with good industry practice to achieve the lowest sustainable cost of providing Reference Services to our customers.[13]

It must also satisfy at least one of several criteria, including:[14]

- to maintain or improve safety, maintain integrity;
- to comply with our obligations;
- to meet demand on the pipeline;
- have an overall economic benefit; or
- where the additional revenue generated exceeds the associated costs.

8.2 Overview

We categorise our capex as either:

- stay-in-business capex – where it maintains or improves our ability to deliver the current quantity of services; or
- expansion capex – where it is required to increase the quantity of services we can deliver.

In line with our Draft Plan released in May 2019, our forecast capex during AA5 is $160 million. This is an uplift compared to prior periods due to the nature of the asset lifecycle, meaning more replacements fall due in AA5.

[13] NGR 79(1)
[14] NGR 79(2)

Since releasing our Draft Plan we have further engaged with our customers and stakeholders and have also refined our cost estimates for the projects and programs we will deliver in AA5.

As it was in our Draft Plan, our capex plan involves all stay-in-business capex, driven by the need to:

- replace our obsolete northern communications system ($31 million);
- replace a number of obsolete control systems, including for compressor units ($19 million) and gas engines ($8 million);
- replace end-of-life turbine exhausts ($5 million);
- redevelop our Jandakot site ($9 million);
- increase our investment in cyber security, data management and digital capabilities, as well as manage and modernise our existing IT systems, including our Customer Reporting System, to ensure they continue to support current service delivery ($17 million); and
- undertake continuing programs of work such as dry gas seal and valve replacements, hardware and software upgrades and cathodic protection.

In AA4 we have spent $122 million on capex (including forecasts for the remainder of the period), which is $8 million above our approved allowance. This has been driven by the need to:

Table 8.1: Summary of AA5 capex

Business Case	$ million	Forecasting Approach	Stakeholder Engagement
Compressor stations	36.7	Historic unit rates	✓ Maintains safety and reliability ✓ Business Case details capex activities related to Compressor Stations
Communications	30.8	Bottom up build utilising specialist external advice	✓ Maintains safety and reliability ✓ Business Case details how we have derived the efficient costs
Compressor unit control systems	19.0	Historic unit rates	✓ Maintains safety and reliability ✓ Business Case details reasons for change in spend between AA4 and AA5
Pipeline and MLV	9.7	Historic unit rates	✓ Maintains safety and reliability ✓ Business Case details reasons for change in spend between AA4 and AA5
Jandakot	8.6	Bottom up build	✓ Business Case details options we considered and how we have derived efficient costs
GEA unit control systems	8.4	Historic unit rates	✓ Maintains safety and reliability ✓ Business Case details reasons for change in spend between AA4 and AA5
Meter stations	8.0	Historic unit rates	✓ Maintains safety and reliability ✓ Business Case details how we respond to changing needs within an AA period
IT Enabling	5.3	Bottom up build utilising vendor quotes and specialist external advice	✓ Supports proactive service offerings ✓ Business Case demonstrates business and customer benefits
All other	33.5	Various	✓ Maintains safety and reliability ✓ Business Cases detail reasons for change in spend between AA4 and AA5 and how we have derived efficient costs

- replace, repair and undertake preventative works on our compressor stations ($26 million);
- replace a large number of end-of-life metering assets, repair piping at meter stations, and upgrade odorant systems and over pressure protection ($26 million);
- replace our obsolete southern communications system ($7 million);
- undertake in line inspections by pigging of the entire length of the pipeline ($12 million);
- refurbish/renovate original compressor station accommodation ($2 million); and
- invest in IT security ($1 million).

8.3 Customer and stakeholder engagement

We engaged with our customers and stakeholders on key areas of our planning, including our proposed capex.

Our customers were broadly comfortable with our approach and program in AA5, but were keen to understand more in several areas including:

- the key areas of increased spend;
- how we ensure we deliver our capex efficiently;
- how our demand forecasts have been factored into our capex program; and
- how we deal with changing business needs during an AA period.

Customers told us they highly value the current level of safety and reliability and would be concerned if this was to change. Customers also wanted to understand the costs of providing modernised billing and a more seamless customer interface.

The feedback and insights gathered through our Shipper Roundtables was reflected throughout our Draft Plan. In relation to capex, we provided information on key areas of increased spend, project governance and procurement, and our performance in AA4.

Customers were broadly comfortable with the capex proposed in our Draft Plan, agreeing that it reflected our earlier discussions and therefore delivered on our promise of 'no surprises'.

Over further Shipper Roundtables held since our Draft Plan we noted some further queries and areas of interest including:

- how changing demand forecasts are reflected in our expenditure plans, and
- have we considered renewable energy in our power supply mix.

These themes are addressed below as well as in the individual business cases that support our forecast capex (provided in Attachment 8.5).

A summary of all customer and stakeholder feedback regarding capex and how we have responded is summarised in Table 8.2.

Table 8.2: Customer and stakeholder engagement: capital expenditure

Topic	Customer and Stakeholder Feedback	Our Response
Capital expenditure	**Stage 1 and 2 Engagement : Developing our Plans**	

	• Customers told us they highly value current levels of reliability and would be concerned if this were to change.
	• Maintaining a strong focus on operational issues is important for reliability and emergency management.
	• Customers requested more information on changes in capex between AA4 and the forecast AA5.
	• Customers asked for clarification on the potential cost duplication of turbine overhauls.
	• One customer asked for clarification on our tender and contracting processes.
	• Customers support an improved customer experience (IT investment) where there is a business case to do so.
	• Customers requested information on:
	  ◦ how we ensure we deliver our capex program efficiently;
	  ◦ how our demand forecasts have been factored into our capex program;
	  ◦ how we deal with changing business needs during an AA period.
		• We provided explanatory information in our Draft Plan, and further information in this Final Plan in Chapter 8, to provide information for customers on our capex spend, including comparative spend with AA4 and how we have demonstrated our forecast is prudent and efficient.
		• We provided clarity to customers on why overhauls are considered to be opex.
		• Our Final Plan does not propose major investment in improved customer experience, but rather proposes that small improvements would be made to billing within existing system improvements.
		• An overview of our tender and contracting process was summarised in our Draft Plan.
		• Our Final Plan includes copies of our Procurement Policy and Purchasing Procedure at Attachments 8.9 and 8.10.

	Stage 3 Engagement : Draft Plan • **Do you support our approach to forecasting capex?** • **Is there sufficient information to understand our proposals and the basis of the costs included?**	
	• Customers were interested in more detail regarding the derivation of costs. • Customers wanted further transparency on the difference between opex and capex activities relating to turbines and GEAs. • Customers want to ensure that AGIG's costs are efficient. • Customers noted that our approach to governance is consistent with what they would expect to see.	• At Shipper Roundtable 7, we explained the supporting information that is provided in the Final Plan including our Asset Management Plan (Attachments 8.1 and 8.2), Stay in Business Capex Plan (Asset Replacement Plan), Cost estimation methodology and IT Investment Plan. Customers agreed that this was sufficient information.
	Stage 4 Engagement: Refining our Plans	
	• No further information was requested in relation to capex.	• This Final Plan reflects feedback from Shippers in Stages 1 to 3.
	Final Plan Outcome	
	• Our capex proposal delivers against customer expectations that current levels of reliability are maintained. • This Final Plan provides supporting information on capex and evidence of our governance arrangements that support cost being efficient. • Customers are comfortable with our approach and level of capex.	

8.4 Our capex investment over time

Our capex is driven by our safety and environmental obligations, the requirements of our customers and the age, performance and wear and tear of our assets. This can result in a lumpy capex profile over time.

In the mid-2000s we undertook a large expansion capex program at a cost of $2 billion to loop 85% of the pipeline and provide associated compression.

Communications equipment and control systems that were installed during this expansion program are now 15-20 years of age, are obsolete and out of support. This makes it increasingly difficult and expensive to maintain this equipment. The likelihood of failure also increases as the equipment ages. Replacement of this equipment in AA5 is essential and drives an increase in our stay-in-business capex program for AA5.

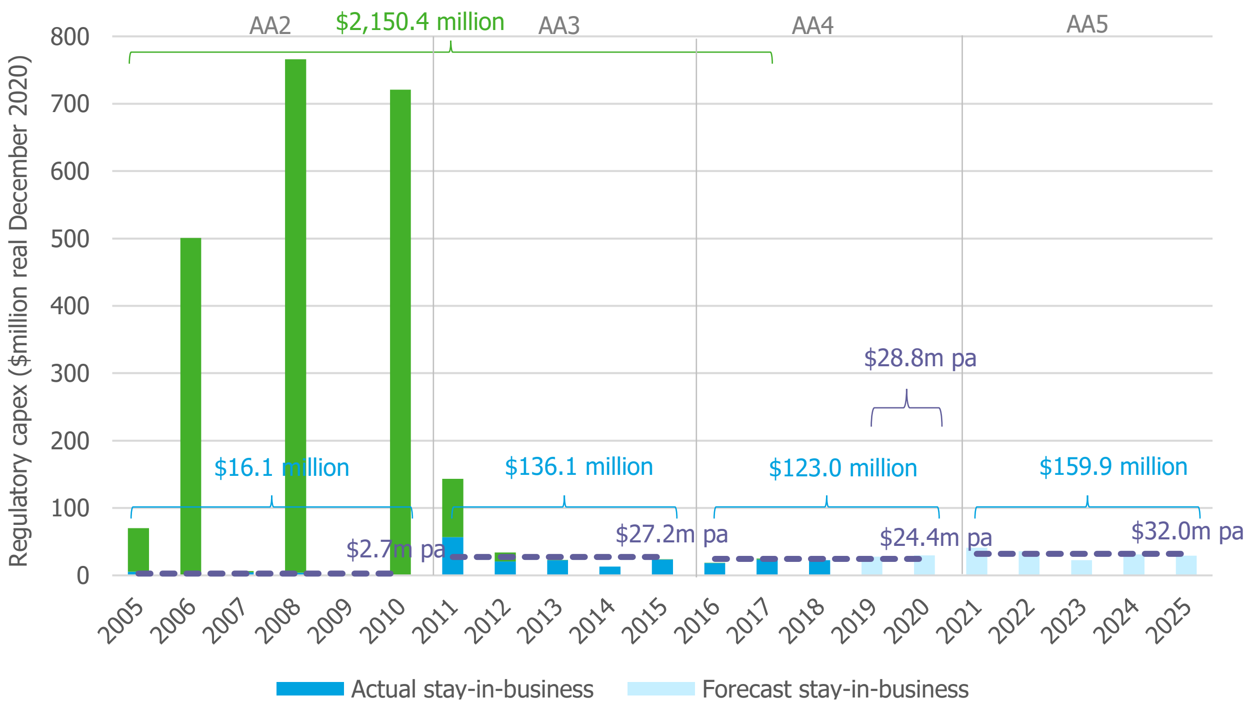
In fact, as the DBNGP approaches 40 years of operations, and 20 years since its expansion, the capex requirements to maintain our current (and valued) safety and reliability performance have increased. We have therefore stepped up our annual investment from 2019 onwards.

As Figure 8.1 shows, capex in AA4 has been, and capex in AA5 will be determined by stay-in-business requirements which focus on maintaining or improving our ability to deliver current Reference Services.

Importantly, the annual average capex in AA5 is in line with the trend in the last two years of AA4, which is forecast to average $29 million.

The type of work is critical to ensure the DBNGP continues to safely and reliably transport gas to our customers every day.

Figure 8.1: Capex since 2005



8.5 How we develop our capex plans

This section describes how we develop the key elements of our capex forecast, being the proposed activities and forecast costs.

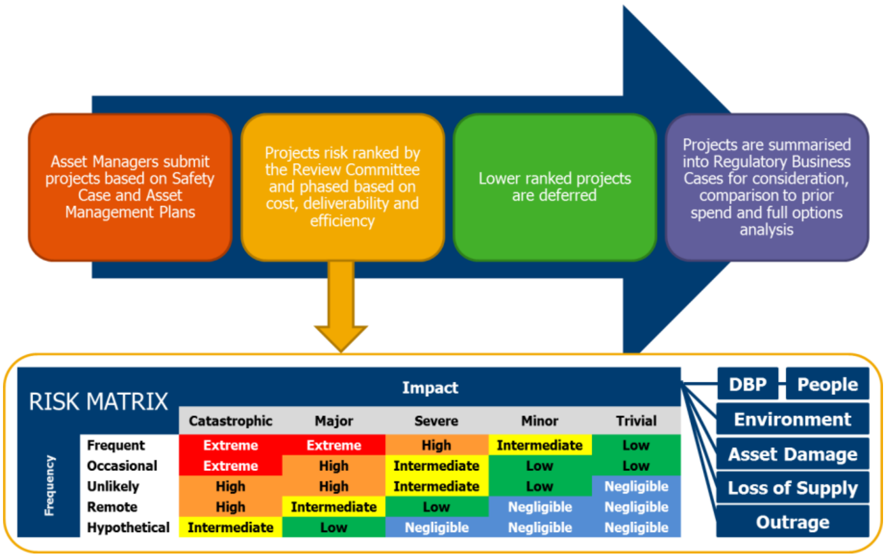
8.5.1 Determining our investment priorities

The programs and projects in our capex plans are built up from our Safety Case and AMPs. Some components of our capex reflects continuing programs of work, such as dry gas seal and valve replacements, hardware and software upgrades and cathodic protection. Other components are key projects such as the northern communications replacement project, replacing gas engine and compressor unit control systems, and turbine exhaust replacement.

Proposed projects and programs are considered by our Project and Procurement Review Committee (PPRC) using the process outlined in Figure 8.2. The PPRC review risk ranking, consider options analysis and optimal phasing based on risk (to the business, people, environment, asset damage, loss of supply and reputation), cost, deliverability and efficiency. Highly ranked projects and programs are summarised into Business Case categories for consideration and comparison to prior spend. Lower ranked projects are deferred.

Since DBP, Australian Gas Networks (AGN) and Multinet Gas Networks (MGN) came together to form AGIG in 2017, a strong focus has been placed on delivering an efficient level of investment required to maintain our strong safety and reliability performance today, while also ensuring we can continue to deliver this performance into the future – being sustainably cost efficient.

Figure 8.2: Summary of our capex planning process and operational risk matrix



More information about our project and investment governance is provided in Section 8.8.

8.5.2 Forecasting efficient costs

Since we released our Draft Plan in May 2019 we have spent time confirming and refining our cost estimates.

There are three specific methods we have used to forecast efficient costs, depending on the nature of the work. These methods consider actual historic costs along with specialised engineering advice and market testing through vendor quotes and expressions of interest.

For ongoing activities that are volume driven we estimate costs by identifying the volume of work to be undertaken and applying a historical average unit rate (typically for the last three full calendar years). Where the program of work is delivered externally, consideration is also given to the specific projects and locations where historical work has been delivered.

For periodic programs of work (those that may not be required in every regulatory period) cost estimates have been developed with regard to historical costs (over a longer time period) for the same, or similar programs of work. Where the program of work has not been delivered for some time (for example, replacing assets at the end of their useful life) we may also have regard to updated vendor and contractor quotes.

For one-off, new or discrete projects which have not been required in the past, efficient costs are determined through a competitive tender process. Where a competitive tender process has not yet been undertaken, an expression of interest is undertaken or a bottom up cost estimate is produced.

A bottom up cost estimate will be derived from recent historical work where that work is sufficiently comparable and/or matched by location and has been delivered externally. Where the work is unique or greater than $5 million, an efficient cost estimate is developed through a front-end engineering design (FEED) study.

Further detail on each of our forecast capex cost estimates is outlined in Attachment 8.7, Cost estimation methodology 2021-25.

8.6 Key drivers

Our capex in AA5 aligns with our vision of:

- delivering for our customers;
- being a good employer; and
- being sustainably cost efficient.

As Figure 8.3 shows, almost 75% of our total capex in AA5 is focussed on delivering for our customers.

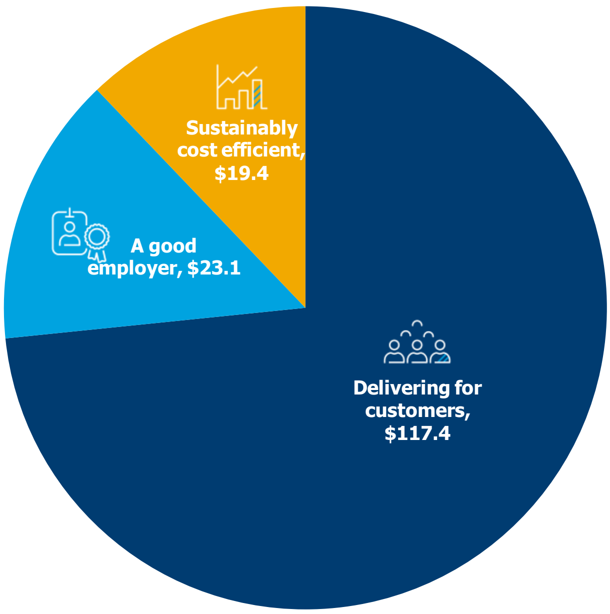
8.6.1 Delivering for our customers

We will invest $116 million on projects and programs that will deliver for our customers through maintaining our strong public safety and reliability performance. This is $5 million less than the $121 million we proposed in our Draft Plan in May 2019 as a result of refining our cost estimates for the projects and programs we will deliver in AA5.

8.6.2 A good employer

We will invest $24 million on projects and programs to maintain our objective of being a good employer. We will maintain strong health and safety performance, continue our refurbishment of existing compressor station accommodation and redevelop our Jandakot facility. This is $2 million higher than the $22 million we proposed in our Draft Plan in May 2019 as a result of refining our cost estimates for the projects and programs we will deliver in AA5.

Figure 8.3: Total AA5 capex by driver ($ million)



8.6.3 Sustainably cost efficient

We will invest $20 million on projects and programs that will ensure we are sustainably cost efficient into the future. We will invest in our IT systems, data management and digital capabilities. This is $4 million higher than the $16 million we proposed in our Draft Plan in May 2019 as a result of refining our cost estimates for the projects and programs we will deliver in AA5.

8.7 Key projects and programs in AA5

The following sections provide further detail on some of the key projects and programs we will deliver in AA5.

Together these key projects and programs represent around 70% of our total capex requirements in AA5.

The remaining 30% of capex in AA5 is made up of ongoing programs of work required to ensure the safe and reliable operation of the DBNGP.

Each of the capex projects and programs is supported by a business case that considers an assessment of options, risks, alignment to our objectives and alignment with the capex criteria in rule 79 of the NGR.

8.7.1 Compressor stations

Compressor stations are integral to the safe and reliable delivery of gas to our customers. There are ten compressor stations along the DBNGP, each with multiple compressor units. Compressor units are run based on the requirements of our customers and must be ramped up or down quickly to meet these needs.

Over AA5 we are forecasting to spend $37 million on compressor stations. This is $2 million less than the $39 million we proposed in our

Draft Plan in May 2019 as a result of refining our cost estimates for the work within this program. The key driver of the compressor stations program is public safety and reliability. The program has two elements:

- the renewal of end-of-life rotating plant (dry gas seal replacement, valve replacement, vibration monitoring and air inlet filters totalling $8 million), instrumentation (controls and fire and gas systems totalling $10 million), power supply ($1 million) and other mechanical equipment ($4 million); and
- repair, rectification and preventative works that provide corrosion protection ($11 million), address safety hazards or improve performance ($4 million).

The program has been identified based on an assessment of options for each of the initiatives within the Compressor Stations program.

The proposed solution is to proactively renew and repair compressor station assets in line with our AMPs, consistent with current practice, and exploring a small number of emerging techniques and technologies to remain sustainably cost efficient.

The other options assessed were:

- undertaking the same level of work and initiatives as completed in AA4, which is inconsistent with our obligations, unlikely to appropriately address all risks and unlikely to be sustainably cost efficient; and
- moving to a replacement on failure approach for all initiatives, which is high risk, inconsistent with our obligations and short-term savings would be outweighed by increased rectification costs in the medium to long term.

Figure 8.4: Aerial view of Compressor Station 10

Around two thirds of the forecast spend on our Compressor Stations in AA5 focuses on maintaining the integrity of Compressor Station assets. If these assets are not proactively renewed or repaired in line with our AMP, they pose a high risk to our operations, the safety of the public and our people, and of damage to other assets at the Compressor Station.

The other third of the forecast spend on our Compressor Stations in AA5 focuses on maintaining the reliability and performance of Compressor Station assets. These assets are critical to maintain the reliability of the DBNGP as an energy source for the electricity grid, particularly as gas-fired power generation plays an increasing role responding to intermittent renewable electricity. If these assets are not proactively renewed or repaired in line with our AMP, our capex cannot be considered as efficient and achieving the lowest sustainable cost of delivering services.

The work to be completed under each initiative within the Compressor Stations program is prioritised based on a number of factors including age, criticality and location. For example the two Compressor Stations to be repainted in AA5 are CS8 and CS10 (with CS9 repainted in 2019) given their close proximity to the coast, comparatively higher exposure to rainfall and industrial pollutants which both speed up corrosion, as well as general inspection of the sites confirming severe coating degradation.

More information on this program of work can be found in the Compressor Stations business case in Attachment 8.5.

8.7.2 Communications

Reliable communications infrastructure is critical to ensure safe operations of the DBNGP at all times and all locations. It is a requirement of the PL40 License to have reliable communications with a specific reliability of 99.9% uptime. Failure to meet this requirement could impede the safe operation of the pipeline and cause for immediate Technical Regulator response.

Current equipment in the northern network (spanning the 1,500km from Dampier to metropolitan Perth) is no longer supported, repaired or replaced by the supplier. This has led to failure at repeater sites (which relay signals along the network) and loss of Supervisory Control and Data Acquisition (SCADA) and operations visibility of sections of the pipeline. High rental cost and access restrictions imposed on shared infrastructure are also posing a risk to operability and reliability.

Communications outages in July 2017

A recent loss of communications demonstrates the importance of our northern communications project.

At 10pm on 7 July 2017 SCADA communications failed to Main Line Valve (MLV) 45 and MLV46 (located south of CS3). This was caused by a failure of the multiplexer (a key component in the communications network). Backup communications kicked in restoring communications to all sites north of MLV45 and south of MLV46.

At around 7am on 8 July 2017 SCADA communications to MLV7 failed, again due to a failure of the multiplexer. As MLV7 supports multiple communications connections, SCADA visibility was now lost between MLV1 and MLV46 (480km of pipeline including three compressor stations).

Later that day metering field officers attended MLV7 but could not restart the multiplexer. They were able to provide a temporary bypass to restore communications between MLV7 and MLV45 (MLV1-7 and MLV45-46 were still black). An electrical control and instrumentation field officer also attended MLV45 and restored both primary and backup SCADA communications paths, however there was still no visibility of MLV1-7 or MLV45 and 46.

On 9 July 2017 a communications field officer attended the MLV and restored the failed multiplexer – SCADA visibility was restored to all sites except MLV45 and 46. Two further sites (Karratha and MLV8) had stopped communicating with the Network Management Server (NMS) in Perth. These sites were also attended. Although the multiplexers were functioning it was feared this could lead to similar outages as MLV7 and MLV45.

At 11am on 10 July the multiplexer at MLV45 (and all visibility) was restored.

Investigations show that all issues were caused by multiplexer units with no warning presented on the NMS. The supplier of the multiplexers no longer operates in the telecommunications industry worldwide.

As shown in the table below, there was a large spike in communications alarms in 2017, and in the following two years, instances of alarms still remain higher than historic levels. This is because temporary repairs are no longer adequate to sustain the integrity of the network.

Summary of communications alarms over the last 4 years

Year	2016	2017	2018	2019
Alarms (#)	25,960	65,881	44,816	45,045

In AA5 we plan to spend $27 million to deliver independent communications infrastructure for the northern section of the DBNGP (a total of 50 sites). This is $4 million more than the $23 million proposed in our Draft Plan due to refining our cost estimates and deferring cabling upgrades at Compressor Stations originally planned for AA4 into the Northern Communications project to achieve delivery synergies.

While the nature of the work is comparable to the Southern Communications work undertaken in the current period, the northern communications system covers 50 main sites spanning around 1,500km of pipeline, many located in very remote areas, compared to the seven main sites spanning around 175km of pipeline south of metropolitan Perth. There are also nine Compressor Stations (which require significant communications capacity) in the northern system, compared to one in the southern system. Finally, the topology of the two systems is fundamentally different. The northern system is a "chain" arrangement connecting sites over large distances, thus requiring more powerful and expensive equipment compared to the southern system which consists of multiple small sites (such as Meter Stations) that each connect to the seven main sites in a "hub and spoke" arrangement over relatively short distances.

The key drivers for this work are delivering for customers in terms of public safety and reliability, and the health and safety of our employees and contractors working along the pipeline. The work includes replacement of original towers and dishes, obsolete analogue radio equipment, power systems and cabling at compressor stations, and rectifiers. We will also increase point-to-point capabilities.

At the end of 2018 we completed a FEED study to better understand the costs of continuing with microwave technology or delivering a different technology solution such as fibre optic or satellite.

The preferred option of full microwave replacement addresses all the issues associated with the northern communications system, provides the capacity required for the future and reduces risk in line with our risk management framework.

We also considered options to:

- continue to take a reactive approach to addressing issues with the system as they arise;
- replacing the system with fibre optic cable; and
- proactively replacing only critical elements of the system.

Continuing to replace reactively or only replacing some of the most critical components would not address all the issues of the current system (particularly capacity). It would also not adequately address the risk the current system poses to the effective operations of the DBNGP and hence our safety and reliability.

Replacing the system with fibre optic would provide additional functionality and further improve risk reduction, however, the benefits of these improved outcomes were not considered to outweigh the additional cost, which is in the order of $90 million.

More information on this program of work can be found in the Northern Communications business case in Attachment 8.5.

8.7.3 Compressor unit control systems

Compressor unit control systems provide critical safety and control functions at all compressor stations. Compressor units are operated remotely from our control room located in Perth. It is important to have a reliable control system that can control processes accurately as well as protect equipment in case of abnormal conditions such as fire, vibration and over pressure.

Much of the existing unit control system was installed in 2006 and has now reached its end-of-life. Vendor support for the system is limited and the cost of procuring spares has increased due to technological obsolescence.

We have implemented a staged replacement approach for compressor unit control systems. This ensures obsolete hardware is changed in a timely manner without impacting the safe and reliable

Figure 8.5: Replacement on compressor unit control panel (UCP)

operation of the DBNGP due to the unavailability of compressor units during control system replacements.

In AA5 we will replace eight units at a total cost of $19 million.

The key driver for this work is delivering for customers in terms of public safety and reliability.

A further benefit of the control system replacement is that we will be able to use the newest version of Solar Turbines' (our key supplier) control optimisation package. The control algorithms for these systems are continually being improved to achieve safer, more reliable and more efficient turbomachinery control – thus mitigating the potential failure of components and the risk of long-term outages.

The proposed program to proactively replace unit control systems is in line with our AMP, manufacturers' guidelines and current practice. This program reduces the risk associated with relying on unsupported or obsolete equipment and, in particular, the risk of turbine units becoming unavailable due to control failures. The program is important in meeting customers' expectations for safety and reliability as outlined in Section 8.3 above.

We also considered options to:

- upgrade all compressor unit control systems to the latest equipment in AA5; and
- move to a replacement on failure policy for compressor unit control systems.

Upgrading all compressor unit control systems to the latest equipment would double the program to be delivered, with minimal reduction in cost per unit. Also, both options would increase the likelihood of an impact to supply, as compressor units must be shutdown for at least 4 weeks to complete the installation of a new control system. As a result, both of these options have not been proposed.

The unit control systems themselves are expensive and are specially designed and built by the equipment manufacturer overseas before being shipped to Western Australia to be installed on site. Their individual value, customisation and size means they are not appropriate to be held as spares. Therefore, moving to a replacement on failure approach for these assets will cause long periods (around six months) of non-operation for effected compressor units. This would significantly constrain our ability to maintain contracted levels of reliability.

8.7.4 Jandakot redevelopment

Our operational facility at Jandakot is nearing 40 years of age and in its current state cannot continue to meet the needs of the business. There is insufficient secure and weatherproof warehousing for materials and spares, office space is limited and more akin to a warehouse than an office environment. The staff amenities and training facilities are inadequate to promote a healthy, engaged and skilled workforce, and there is poor traffic ingress and egress to site and insufficient parking.

The facility is of a substantially poorer quality relative to adjacent facilities for gas distribution operated by ATCO Australia and for electrical transmission operated by Western Power. These three facilities, were co-designed and co-located by SECWA, at Jandakot before the privatisation of the gas transmission business in 1998 followed later by the gas distribution business.

The site has undergone reactive upgrades over the years including:

- additional warehousing and office space built as part of the Stage 5B expansion in 2009;
- conversion of original storeroom to a fully equipped back up control room in 2009;
- conversion of workshop space into office space in 2005 and additional works when the warehouse was built in 2011;
- additional demountable office space was also added in 2005, before removing old demountable space containing asbestos in 2011;
- security, fencing and workshop upgrades in 2011; and
- removing an old demountable that contained asbestos in 2017.

However, there remain several issues with the site that would be addressed more efficiently through the planned redevelopment, rather than continuing to address them on an ad hoc basis.

During AA5 we are planning to redevelop the site at a cost of $9 million (this is $1 million higher than the $8 million proposed in our Draft Plan as a result of refining our cost estimates).

The redevelopment will provide:

- additional warehouse storage;
- a redesigned office building which meets current building standards and consolidates office space across the site;
- purpose-built training and meeting facilities;
- separation of ingress and egress for staff and logistics; and
- additional long-term parking for remote staff.

Other options considered were to:

- continue to take a reactive approach to addressing issues with the facility as they arise;
- lease a new fit-for-purpose facility;
- build new facilities at a different location; and
- a staged redevelopment over AA5 and AA6.

Continuing to reactively address issues with the facility as they arise would not achieve the site requirements in a timely manner and would also cost more over time due to the efficiencies gained in a planned redevelopment.

The estimated cost of leasing a new fit-for-purpose facility or building new facilities at a different location is likely to outweigh the cost of redevelopment at the current site, particularly after including the costs of increased disruption from relocation and factoring in the market risk arising from selling and purchasing a new property and building or fitting out a new facility. Additionally, the current location of the facility is adjacent to the main transport arteries in Perth that enable quick and efficient travel and response to address the needs of the DBNGP.

Figure 8.6: Aerial view of Jandakot depot

8.7.5 IT

Our information and technology systems are integral to delivering safe, reliable and efficient services. Our digital strategy for AA5 is based on a consideration of our current state, emerging industry trends and drivers, and a fit-for-purpose future state.

The confidentiality, integrity and availability of information and systems is also critical to ensure we deliver services in line with our various regulatory obligations and requirements, such as the *Security of Critical Infrastructure Act*, *Privacy Act* and Foreign Investment Review Board (FIRB) reporting obligations.

Our analysis has made it clear to us that an uplift in IT investment (which has had minor focus and limited investment in the past) is required.

Some key areas for improvement we have identified include:

- the accessibility, long-term dependency and supportability of the Customer Reporting System (CRS);
- potential lost productivity due to manual processing and lack of digital collaboration;
- unlocked potential of existing data and information; and
- a growing focus on the cyber threat to industrial control systems worldwide (for example, the introduction of Security of Critical Infrastructure legislation in Australia).

Our digital strategy and roadmap of initiatives for AA5 is driven by our objective to be sustainably cost efficient. It also delivers for customers by securing against threats, modernising systems and increasing digital capabilities. This investment also furthers our vision to be a good employer by modernising systems and investing in data management and business intelligence.

The total forecast spend is $17 million; this is in line with the estimates in our Draft Plan.

Our AA5 IT initiatives fall into five main areas:

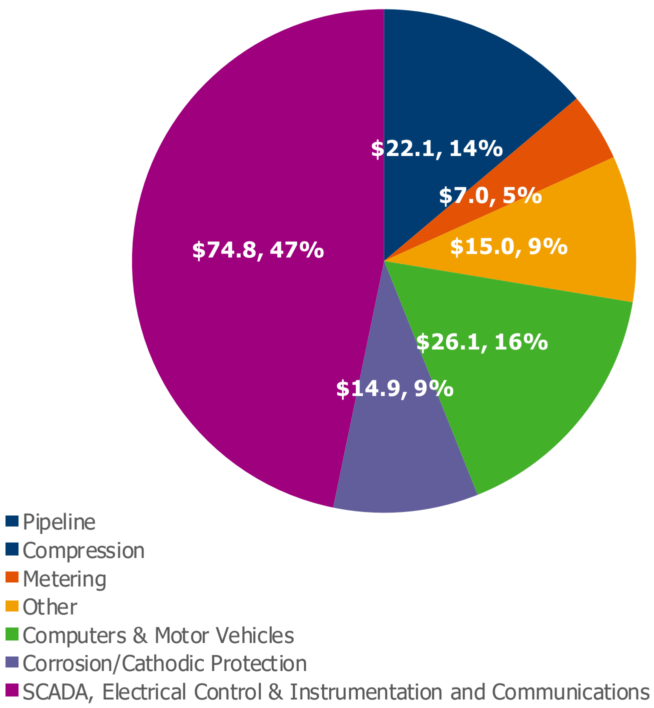
- CRS enhancement ($2 million) – this project will upgrade the CRS user interface so it is compatible with use on mobile devices while continuing to support upgrades to the system as business requirements and customer needs change;
- IT enabling ($6 million) – this is an improvement of the delivery of DBP IT services up to standard industry practice, enabling effective services to the customer and ensuring compliance with regulatory obligations;
- IT sustaining applications ($5 million) – this will maintain the current levels of IT services and mitigate against risks to our core business systems through a prudent cycle of system upgrades and replacements;
- IT sustaining infrastructure ($3 million) – this will ensure existing IT infrastructure continues to support our business systems; and
- IT security ($2 million) – this ensures a proactive approach to IT security and an improvement in our cyber resilience maturity level commensurate with the size and criticality of our operations so that all IT services are delivered safely and securely, are resilient to external threats and comply with our security obligations.

The levels of investment proposed are considered the minimum required to achieve our objectives and provide robust and resilient technology systems to support our business needs over the AA5 period.

8.7.6 Summary of our AA5 capex by asset category

Figure 8.7 shows our AA5 capex by asset category. As described in detail above, our expenditure in AA5 is largely driven by the replacement of obsolete and end-of-life communications and control systems, as well as renewal of compressor station equipment to ensure we can continue to deliver gas safely and reliably.

Figure 8.7: AA5 capex by asset category ($million, Dec 2020)



8.8 How we deliver our capex efficiently

We operate within a framework of external and internal controls which govern the way we plan, assess, procure and deliver capital works. This framework ensures we are making sound investment decisions for our customers, our stakeholders and our business.

8.8.1 Our Safety Case and Asset Management Plans

As discussed in Section 7.8.1, our Safety Case is the primary document outlining how we operate the DBNGP in compliance with our obligations under the *Petroleum Pipelines Act 1969 (WA)*, regulations and our operating licences.

The Safety Case provides assurance that the systems, processes and procedures we have in place will support us in systematically and continually identifying and assessing threats to asset integrity, and therefore ensure the safe and reliable operations of the DBNGP.

Our AMPs guide the way we invest in our assets and help to ensure the capex activities we undertake are clearly aligned to our vision. An overarching DBNGP AMP sets a framework, while specific AMPs outline key risks and controls for various asset types. These AMPs demonstrate the logical development of asset improvement and replacement plans, and complete the feedback loop by monitoring asset performance.

The AMPs also outline how we continually monitor, evaluate, plan and undertake asset integrity assessments to extend the remaining life, improve, replace, or where necessary, retire assets. This framework ensures that efficient, reliable and safe operations of the DBNGP are maintained.

8.8.2 Financial governance

Our business planning doesn't stop with each AA period. We continually update our capex plans to respond to changing business needs.

In the annual planning process, proposed capex projects are risk ranked and then submitted to our Project and Procurement Review Committee (PPRC) where we consider funding requirements, resource availability and the optimised delivery of each project. Risk ranking is refreshed to ensure projects identified as required in the medium term are accelerated or deferred where prudent, and to allow us to respond to significant unplanned events.

Capex projects are presented to the the Board for approval if a project is above the threshold value. Once approved, projects are then managed and monitored in accordance with our Project Management Methodology (PMM) which we outline below.

8.8.3 Internal Audit

As outlined in Section 7.8.3, our internal audit function provides independent assurance that our risk management, governance and internal control processes are operating effectively.

During the 2016-19 period, our cyber security, AMP and safety case implementation were reviewed.

We have implemented a Cyber Security Framework as well as other cyber security controls as a result of the cyber security review recommendations. We are continuing to invest in this area in AA5 to ensure our systems are robust and resilient to threats.

The AMP review assessed the measures we take for the proper management of assets and implementation of the Safety Case used in the provision and operation of services, and where appropriate, the construction or alteration of relevant assets. No significant control weaknesses were identified. The review identified six findings as 'action recommended' in relation to the misalignment between the AMP and Maximo processes. This was also an area with some further findings identified as opportunities for improvement, supporting the need for us to deliver our Maximo Redesign project early in AA5.

8.8.4 Project governance

Our Project Management Methodology (PMM) outlines our approach to deliver projects. It outlines a process to ensure projects are executed consistently and in a manner that represents industry best practice.

The PMM sets out the monitoring and control required throughout the project lifecycle. It also includes key requirements in relation to planning, risk, quality, communication, schedule, environment and reporting, close out, procurement, cost, audit and regulatory obligations. It is based on the principles outlined in the Project Management Institute's Project Management Body of Knowledge.

Our Project Management Office (PMO), part of AGIG's Transmission Asset Management Division, is responsible for the quality and fitness for purpose of the PMM as well as ensuring the PMM is appropriately applied in the business. The PMM is reviewed at least every five years.

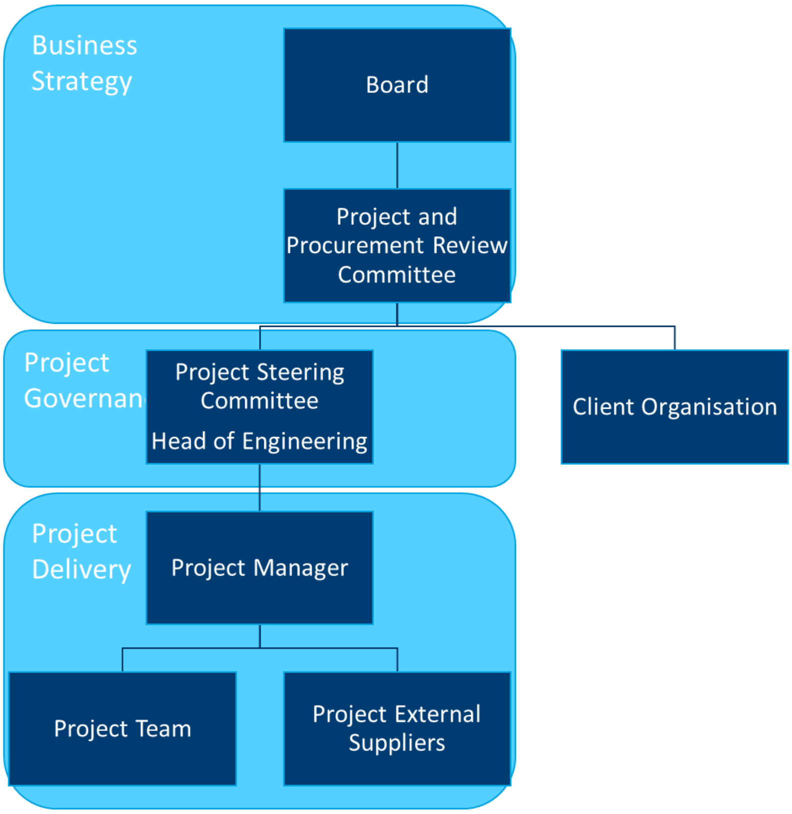
The PMM outlines the approval process and major project milestones at each stage of the project lifecycle. Our project lifecycle is depicted in Figure 8.8.

The project governance structure that supports approvals at each stage, depending on the size, cost and nature of the project, is depicted in Figure 8.9.

Any changes that occur during project execution are managed through the PMM project change request process. This process ensures there is governance around changes in scope and cost at all stages of the project lifecycle, including execution.

Figure 8.8: Our project lifecycle

Figure 8.9: Our project governance structure



8.8.5 Procurement

All procurement activities for both opex and capex are subject to our Procurement Policy and Purchasing Procedure (see Attachments 8.9 and 8.10). This ensures we carry out these activities in an efficient, cost effective, confidential and ethical manner. The policy also ensures we:

- maximise cost savings;
- mitigate risks associated with the provision of goods and services; and
- achieve excellence in both operational and financial performance.

AGIG's Procurement Group is responsible for ensuring the Purchasing Policy is up to date and appropriately applied in the business.

Table 8.3 outlines the minimum information requirements that must be met, depending on the value being procured. All procurement activities exceeding a value of $100,000 must be competitively tendered to at least three vendors, and exceeding $1 million to at least four vendors.

Contractual or pricing agreements for ongoing supply of goods or services are reviewed annually.

Our Delegation of Financial Authority covers all financial transactions within our organisation, with key delegations highlighted in Table 8.4. It outlines the level of financial authority at each level within our organisation. Only the CEO has financial delegation to approve funds for unbudgeted initiatives, and only where it fits within the overall approved budget. This provides strong financial controls and governance in the delivery of capex.

Table 8.3: Minimum purchasing requirements

Value	Minimum requirement
<$20k	One written quote, prices and info emailed
$20k-<$100k	Two written quotes
>$100k-<$1,000k	Tender from three vendors
>$1,000k	Tender from four vendors

Table 8.4: Key Delegated Financial Authorities

Position	DFA (within budget)
CEO	$5 million
GM Transmission Asset Management	$500,000
GM Transmission Operations	$500,000

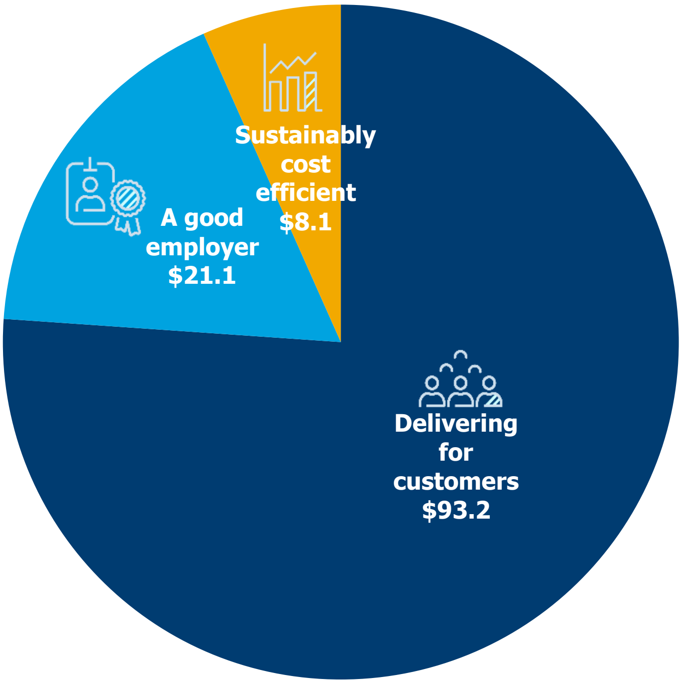
8.9 Our performance in AA4

We have invested $92 million of capex during AA4 up to the end of 2019 and are forecasting to invest a further $30 million in 2020, totaling $122 million by the end of the period. Our AA4 capex is designed to achieve our objectives of:

- delivering for customers;
- being a good employer; and
- being sustainably cost efficient.

During the AA4 period, 76% of our capex is focussed on delivering for our customers.

Figure 8.10: AA4 capex by driver ($ million Dec 2020)



8.9.1 Delivering for customers

We have invested $71 million (forecast $93 million by the end of the period) on projects and programs that enable us to provide the services customers require and value. To date, we have delivered 100% system reliability, have required zero curtailments of our customers, built standalone communications infrastructure for the southern section of the pipeline, completed in-line inspection, using an intelligent pig along the entire length of the pipeline (around 2,500km including loops), and replaced end-of-life metering.

8.9.2 A good employer

We have invested $15 million (forecast $21 million by the end of the period) on projects and programs to support our vision to be a good employer. We have delivered strong safety performance, completed working at heights upgrades and achieved leading employee engagement. We also undertook minor refurbishments required at our Perth office and Jandakot depot and began refurbishing original compressor station accommodation, with one of nine to be completed by the end of AA4.

8.9.3 Sustainably cost efficient

We have invested $7 million (forecast $8 million by the end of the period) on projects and programs to ensure we are sustainably cost efficient. We have increased our investment in cyber security in response to threats and external obligations, which was not forecast in our AA4 approved allowance.

8.10 Key projects and programs we have delivered in AA4

The following sections provide some further detail on some of the key projects and programs that we have delivered (and will continue to deliver) during the AA4 period. Together these key projects and programs represent 62% of total capex invested in AA4.

8.10.1 Compressor stations

As outlined in Section 8.6.1, compressor stations are integral to the safe and reliable delivery of gas. We undertake regular works at our compressor stations to ensure the integrity of our compressor station assets.

By the end of AA4 we will have invested $26 million on compressor stations, this is $6 million less than we forecast in our Draft Plan due to reprioritisation of works in 2020.

This is $15 million (37%) below the allowance approved in our AA4 decision. During the AA4 period we have:

- renewed end-of-life rotating plant (valves, seals, hot gas path, fuel gas pressure control, air compressors, aftercoolers and air inlet filters totalling $8 million), instrumentation (controls and fire and gas systems totalling $3 million), power supply ($3 million) and other mechanical equipment ($3 million); and
- repaired compressor stations pipework and undertaken preventative works that will protect pipework from corrosion ($4 million) and safety hazards as well as projects to improve performance ($5 million).

The key reasons for variation from the approved program for AA4 are:

- cyclone activity in the north of the state delayed underground piping refurbishment works;
- DBP was able to negotiate a longer timeframe to complete fire suppression installation on Stage 3 compressors with its insurer due to the existing fail-safe mechanisms in place for these compressor units, meaning a large portion of this program has been deferred from AA4 to AA5; and
- the upgrade of fuel gas skids, NP HMI, data vibration monitoring and PLC replacements have been deferred in the annual investment review process to allow for other higher priority works, such as over pressure protection and piping repairs at meter stations (see 8.10.2 below).

The variation shows how we have responded to changing business needs during the period and still delivered on the key drivers of the compressor station program, being to maintain public safety and reliability.

Figure 8.11: Refurbishment of underground piping at CS1

8.10.2 Meter stations

Meter stations ensure accurate billing and supply to all customers. Metering equipment at inlet and outlet stations must enable remote operation and accurately monitor and record quantity, quality and specification data for gas delivered. Meter stations also need to be maintained in line with Australian Standards (AS2885).

By the end of AA4 we will have invested $26 million in our meter stations. This is $18 million above (two and a half times) the allowance approved in our AA4 decision. The key driver of our meter stations program is maintaining public safety, reliability and customer service.

During the AA4 period we have:

- replaced and refurbished metering and other mechanical equipment including flow measurement, quality measurement and heating ($4 million);
- replaced valves and upgraded over pressure protection ($11 million);
- upgraded odorisation equipment ($2 million); and
- repaired meter station corroded piping and undertaken preventative works that protect facilities from further corrosion ($8 million) and safety hazards controls ($0.2 million).

The key reasons for variation from the approved program for AA4 are:

- significant repairs to piping at several meter stations that were not initially forecast, but became a high priority within the period;
- a change in over pressure protection measures required at meter stations as agreed between DBP and the safety regulator, DMIRS; and
- major upgrades to odorant systems to address risks identified by an assessment of system failures and leak incidents.

8.10.3 Communications

As highlighted in Section 8.7.2, communications infrastructure is critical to ensure safe operations of the DBNGP at all times and all locations.

We have invested $7 million to deliver standalone communications infrastructure for the southern section of the DBNGP which comprises seven sites between Perth and Bunbury. This is $5 million above the allowance approved in AA4.

The AA4 forecast developed in 2015 was based on upgrading existing shared infrastructure with another utility. However, further investigations and analysis of the relative cost, conditions and risks of various options determined the most prudent and efficient option would be new standalone infrastructure.

Standalone infrastructure has the benefits of:

- longer asset life;
- no annual rent costs;
- quicker delivery; and
- reduced administration in terms of contractor and employee training and site induction.

The key drivers for this work are maintaining public safety and reliability, and the health and safety of our employees and contractors working along the pipeline. The work includes installing communications towers, site security, microwave dishes, new digital radio equipment, power systems and cabling. We have also increased our point-to-point capabilities making the system more resilient.

Further to this we have invested $2 million to upgrade communications at a number of meter stations, replace ultrahigh frequency (UHF) radios which run on a discontinued radio frequency, upgrade network cabling, complete minor repairs to communications huts and strengthened our telecommunications resilience.

8.10.4 Pipeline and mainline valve inspections

Our pipeline and mainline valves (MLVs) are integral to the safe and reliable delivery of services. We undertake regular and routine condition monitoring, including intelligent pigging, pressure vessel and pressure relief valve inspections. These inspections highlight anomalies so we can monitor any deterioration in asset condition and take action to repair any defects proactively.

By the end of AA4 we will have invested $13 million to undertake pipeline and MLV inspections. This is $2 million above the allowance approved in our AA4 decision. Pressure vessel and pressure relief valve inspections were initially forecast as part of pipeline costs in AA4.

As noted in our Draft Plan in May 2019, we have detected naturally occurring radioactive materials (NORMS) throughout the DBNGP, which has increased our inspection and cleaning costs. We have also had some issues with pig receivers and launchers isolation valves leaking. We are planning to replace these valves in AA5 in preparation for our next pigging program in AA6.

The key driver for this work is maintaining public safety, process safety and reliability. Faults in the pipeline can cause rupture affecting public safety and service delivery. Corrosion defects at pipework interfaces and valves can cause supply interruption particularly at the interfaces associated with pipework to the customer delivery locations. Reference is made to the Varanus Island incident in 2008 that resulted in the cessation of gas supply from this production facility.

It is prudent and efficient to address anomalies and defects on the pipeline and MLV assets before they

Figure 8.12: Alcoa Wagerup meter station, a telecommunications tower and pigging of the pipeline in 2018

escalate resulting in catastrophic failures. This is particularly important in gas transmission where large volumes of gas are transported at very high pressure.

8.10.5 Accommodation

We have accommodation facilities at nine of our compressor stations along the DBNGP. These facilities support our field staff who work and stay for multiple nights at our remote compressor stations. By the end of AA4, all compressor station accommodation facilities will have aged by their stages of expansion as shown below. Most of the accommodation facilities were installed by 1987 – during the ACS Project to complement the original accommodation facilities commissioned in 1981.

Table 8.5: DBNGP Accommodation Facilities

DBNGP expansion stage	Year	Years in service (as at 2019)
Original	1981	35
ACS project	1987	32
Stage 2	1997	22
Stage 3A	2000	19
Stage 4	2004	15
Stage 5A	2007	12
Stage 5B	2010	9

We originally forecast $9 million would be required to build new accommodation facilities at our compressor stations, and $0.8 million to continue minor refurbishments at existing compressor station accommodation facilities.

We have completed further project development as was anticipated at the time of approval and have concluded not to progress with building new accommodation facilities at this time. Further analysis of options has shown:

- it is difficult and much more costly than we had thought to secure land outside of our existing compressor station sites to build new accommodation facilities;
- newer technologies, silencing material such as mufflers, centralised air conditioning and other noise mitigation initiatives at our compressor stations have enabled us to reduce noise at a more cost-effective price;
- process safety initiatives for inspection of below ground pipework and interface corrosion inspections within our compressor stations have been introduced as additional controls to reduce the risk of catastrophic failure to ALARP;
- the retrofitting of fire suppressant systems at sites that currently don't have suppressant systems adds value to achieving ALARP and the co-location of accommodation facilities within the confines of compressor stations;
- engagement with staff has indicated the provision of additional amenities would greatly improve the health and wellbeing of our remote field staff; and
- given all of the above, reinforcement works to facilities in cyclone prone environments would be more cost-effective than building new accommodation units.

Therefore, rather than the $9 million originally forecast, we are investing $2 million in our compressor station accommodation during AA4. This includes refurbishment of bathrooms and kitchens ($1.5 million) and adding fitness facilities ($0.9 million). This program will continue into AA5 and will also include further renovations to accommodation facilities to improve noise and reinforce facilities in cyclone prone areas.

8.10.6 IT security

IT security has become an increasingly important area for utilities in recent years. In AA4 we are investing $1.4 million in IT security. There was no capex allowance for IT Security in our AA4 decision.

The key driver for this work is being sustainably cost efficient. It also delivers for customers and employees by ensuring:

- we meet our obligations under the *Security of Critical Infrastructure Act 2018,* which was introduced during the AA4 period;
- we have a strong cyber security policy and culture;
- we have robust systems; and
- we are able to respond to threats.

The work includes upgrading our cyber security and establishing a cyber security framework ($0.9 million), and improving our data protection by introducing multifactor authentication and standardising rights and role-based access across the business ($0.5 million).

8.10.7 Summary of our AA4 capex by asset category

Figure 8.13 shows our AA4 capex by asset category. As already described above our expenditure in AA4 has been driven by renewal of compressor station and metering equipment, the replacement of obsolete and end-of-life communications, cathodic protection (including intelligent pigging and in line inspection of the entire DBNGP) and other ongoing activities to ensure the ongoing safety and reliability of the DBNGP.

8.11 Summary

Our capex in AA5 will ensure we:

- maintain the strong safety, reliability and service performance we are delivering in AA4;
- have a healthy, engaged and skilled workforce; and
- are sustainably cost efficient into the future.

Key projects and programs we will deliver are:

- upgrading of the standalone communications infrastructure for the northern section of the DBNGP;
- replacement of obsolete control systems to maintain strong reliability; and
- greater investment in our IT systems, data management, digital capabilities and cyber resilience.

Together with the rest of our AA5 capex program, these projects will deliver the strong safety and reliability valued by our customers.

As demonstrated by our performance in AA4, we will deliver our capex program prudently and efficiently by applying our established financial, project and procurement governance frameworks and reassessing our plans where our business needs change.

Figure 8.13: AA4 capex by asset category ($million, Dec 2020)

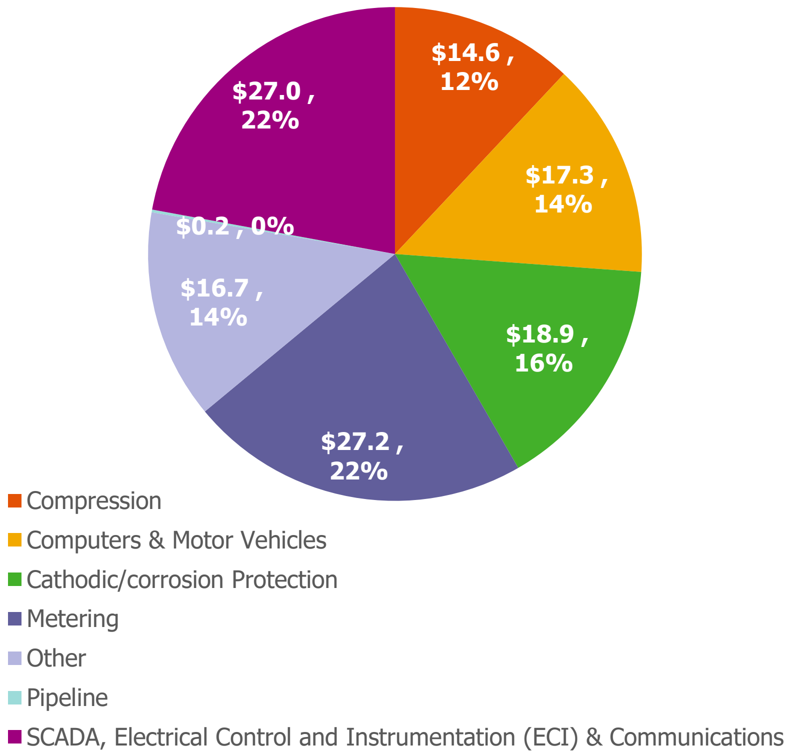


Table 8.6: Summary of AA5 capex

Business Case	2021	2022	2023	2024	2025	Total AA5
Compressor stations	9.7	5.3	5.9	7.4	8.3	36.7
Communications	15.4	15.4	0	0	0	30.8
Compressor unit control systems	0.0	4.7	4.7	4.8	4.8	19.0
Pipeline and MLV	2.1	1.7	2.4	2.0	1.6	9.7
Jandakot	0.5	0.0	0.0	4.1	3.9	8.6
GEA unit control systems	0.9	0.0	1.4	3.3	2.8	8.4
Meter stations	2.0	1.4	1.6	1.4	1.6	8.0
IT Enabling	1.5	1.3	1.4	0.6	0.6	5.3
All other	9.2	6.3	4.9	7.5	5.6	33.5

9 Capital base

Our capital base is set to fall from $3,357 million at the beginning of AA5 to $2,840 million over the AA5 period because new investment is lower than the depreciation of existing assets.

IN THIS CHAPTER

Our approach to forecasting our capital base recognises the economic life of the DBNGP in the context of the changing energy market

Our asset categories are updated to reflect the economic life of individual asset classes and is consistent with good industry practice

Our capital base reflects the value of past investments that we have made on the DBNGP, but not yet recovered from our customers.

The current value of our capital base (at the end of 2019) is around $3.42 billion and is forecast to fall to $3.36 billion by January 2021 when AA5 commences. This Chapter discusses our approach to adjusting our capital base over AA4 and AA5.

9.1 Regulatory framework

We are required to adjust our capital base to reflect the difference between estimated and actual capex in AA4 (net of any amounts contributed by our customers), inflation and for forecast depreciation. We are also required to make certain other adjustments to our capital base, such as to remove the value of any assets that we have sold or to reflect the reuse of redundant assets in the current AA period.[15]

Our capital base over AA5 is then adjusted for forecast capex, depreciation and inflation.

Our depreciation schedule is required to be designed:

- so that our prices vary over time in a way that promotes the efficient growth in services provided by our business;
- so that our assets are depreciated over their economic life;
- to allow for changes in the expected economic life of particular assets;
- so that an asset is depreciated only once; and
- to allow for our reasonable needs for cash flow to cover our costs.[16]

9.2 Customer and stakeholder engagement

We engaged with our stakeholders and customers on our approach to the capital base. The decarbonisation of the energy sector and the role of the DBNGP in a decarbonised future was a focus throughout the engagement program.

During Stage 1 of our engagement program, customers acknowledged the increasing use of renewable electricity in Western Australia and the impact this was already having on their businesses. They also acknowledged the uncertainty this introduced about the future use of gas and the DBNGP.

We outlined our proposed approach to depreciation incorporating the

[15] NGR 78
[16] NGR 89(1)

categorisation of our assets and our intention to examine the economic life of the DBNGP as a whole.

Following publication of our Draft Plan, the rationale of our proposed approach to asset recategorisation was understood but further information was sought on the detail of the proposed mapping. This was provided to Shipper Roundtable participants and further detail included in Attachment 9.1.

Customers also requested more information about our examination of the economic life of the DBNGP as whole. We provided Shipper Roundtable participants with a detailed overview of our proposed approach, including its rationale, an overview of the modelling exercise underpinning our proposal and an overview of the price implications. Our Final Plan provides further detail in Attachment 9.2 and in the expert report provided by ACIL Allen (Attachment 9.3).

Overall, given the rapidly changing renewable energy market, and consistent with the challenges that many of our customers face, there was a broad recognition and acceptance by customers and stakeholders that the role of the DBNGP in a future decarbonised energy sector is uncertain. Some customers accepted the need to amend the overall asset life to match a revised economic life, however some customers reserved their position until we provide our Final Plan.

A summary of all customer and stakeholder feedback regarding the capital base and how we have responded is summarised in Table 9.1.

Table 9.1: Customer and stakeholder engagement: capital base

<table>
<tr><th>Topic</th><th>Customer and Stakeholder Feedback</th><th>Our Response</th></tr>
<tr><td rowspan="4">Future Focus and Capital Base</td><td colspan="2">Stage 1 and 2 Engagement : Developing our Plans</td></tr>
<tr><td>• Customers acknowledged the increasing use of renewable electricity and resultant uncertainty around future energy models.
• Many stakeholders noted the rapid changes to the energy industry with a focus on renewable energy to decarbonise energy supply and electricity specifically; there was uncertainty about the future role of gas and the DBNGP more specifically.
• Customers asked if an early recovery of depreciation will impact on the price in the future.</td><td>• At Shipper Roundtable 5 we discussed how a future focus is a key consideration in our approach to asset categorisation and depreciation – in order to deliver in the long-term interests of customers.
• We proposed our approach to the capital base is to:
  ◦ align asset categories and lives with good industry practice, including by having regard to other transmission pipelines in Australia; and
  ◦ examine the economic life of our longest-lived assets and the DBNGP system as a whole.
• We have ensured that the price impacts of our depreciation proposals are made clear to customers as our plans are developed and in our Final Plan in Chapter 9.</td></tr>
<tr><td colspan="2">Stage 3: Draft Plan Consultation
• Is our approach to adjusting the capital base, including our assumed asset categories asset lives and aligning the economic life of the main and loop lines appropriate?</td></tr>
<tr><td>• Customers supported our approach to asset categorisation but would like visibility of the mapping.
• Customers requested more detail on the change in economic lives, including evidence of regulatory precedent.
• Customers asked for information on the rationale for considering the economic life of the DBNGP system as a whole.
• Customers asked for evidence that supported the proposal to act now on accelerated depreciation.</td><td>• At Shipper Roundtable 7, we showed a mapping of asset categorisation differences between AA4 and AA5.
• In August 2019 we circulated to Shipper Roundtable participants an Information Paper relating to our position on depreciation. The Information Paper provided customers with supplementary information and detail regarding the rationale in response to Draft Plan feedback. It was prepared to facilitate more in depth engagement with our customers. Our Final Plan provides a further update to the information provided at Attachments 9.1 and 9.2.
• Additional information regarding depreciation and asset lives was presented to customers at Shipper Roundtable 7 and 8, including:
  ◦ an overview of the economic modelling evidence that supports acting now (e.g. WOOPs model, future carbon scenarios); and
  ◦ further evidence on the decarbonisation transition taking place in the energy industry.</td></tr>
</table>

Topic	Customer and Stakeholder Feedback	Our Response
	Stage 4 Engagement : Refining our Plans	
	• Some customers questioned whether there was enough evidence available to support our proposed approach to depreciation to reflect a revised economic life. • Customers queried the price impact of the proposed approach to depreciation of the loop line.	• We provided the best available price impact information to customers to facilitate the discussion based on forecast modelling, indicating a price impact of \$0.6-0.8 per GJ due to the changing depreciation profile of the DBNGP. • We continued discussions with customers regarding depreciation, noting that while there was broad recognition and acceptance of an uncertain future, some customers were not actively supporting the proposal. • Our Final Plan provides further information on our depreciation proposals in Chapter 9 including detailed supporting information in Attachments 9.1 and 9.2, and a report from ACIL Allen on the framework adopted at Attachment 9.3.
	Final Plan Outcome	
	• Our Final plan provides comprehensive supporting information and rationale for our proposed approach to depreciation of our capital base. • Our rationale for asset recategorisation was understood by our customers and stakeholders as reasonable and consistent with good industry practice.	
	• There is broad recognition and acceptance by customers and stakeholders that the future of the DBNGP is uncertain given the rapidly changing renewable energy market, consistent with the challenges that many of our customers face. Some customers accepted the need to amend the overall asset life to match a revised economic life, however some customers reserved their position until we provide our Final Plan.	

9.3 Capital base as at 1 January 2021

We have adjusted (or rolled-forward) our capital base as at 1 January 2016 for actual capex and inflation, and for forecast depreciation over the current AA period. We have used forecast information for 2019 and 2020 as actual information is not yet available.

Table 9.2 shows the adjustments we have made to our capital base over the current AA period. In keeping with the rest of this document, it is shown in dollars of December 2020, and as such, does not show the impact of inflation.

Table 9.2: Roll forward of the capital base 2016 to 2021 ($ mil Dec 2020)

	2016	2017	2018	2019	2020
Capital base at 1 Jan	3,755.8	3,667.9	3,583.7	3,496.5	3,420.8
Plus Conforming Capex	18.3	24.6	22.4	27.5	29.8
Less					
Disposals and redundant assets	-	-	-	-	-
Depreciation	106.2	108.9	109.6	103.2	93.3
Capital base at 31 December	**3,667.9**	**3,583.7**	**3,496.5**	**3,420.8**	**3,357.3**

Table 9.3: Forecast capex by regulatory asset category in AA5 ($ mil Dec 2020)

	2021	2022	2023	2024	2025
Pipeline	0.0	0.0	0.0	0.0	0.0
Compression	6.2	3.5	4.0	3.8	4.6
Metering	1.8	1.2	1.4	1.2	1.4
BEP Lease	0.0	0.0	0.0	0.0	0.0
Computers and Motor Vehicles	7.4	5.3	4.0	5.7	3.7
SCADA/ECI/Comms	19.7	21.9	8.7	12.3	12.2
Cathodic/Corrosion protection	3.5	2.9	3.1	2.9	2.4
Other	2.7	1.3	1.1	5.0	4.8
Total capex	41.3	36.1	22.4	31.0	29.2

9.4 Capital base as at 31 December 2025

This section discusses the forecast adjustments we propose to make to the capital base over the AA5 period, in terms of capex, depreciation and inflation.

9.4.1 Capital expenditure

Our forecast capex was discussed in Chapter 8 of this Final Plan. Capex by asset category for each year of AA5 is shown in Table 9.3. The asset categories used to adjust our capital base have been set in line with industry practice. We discuss this in more detail below.

9.4.2 Forecast depreciation

We are required to design the depreciation schedule according to the requirements of the NGR, specifically rule 89(1) (see Section 9.2) each time we make an AA proposal to the ERA. However, the issue of economic lives, and thus depreciation, has received comparatively little attention since our current asset lives were first determined in AA1.

We believe that this is no longer a tenable approach; major changes in the energy sector, in particular in respect of renewable energy, mean that the monopoly power regulation is intended to address is likely to be challenged. This requires us to devote attention to depreciation to ensure that, when competition arrives, we are ready to continue to provide the services our customers desire and at a price which reflects the long-run interests of consumers. The NGR specifically envision the adjustment of economic lives in response to these types of factors (rule 89(1)(c)).

We need to act now, rather than delaying action because the long-lived nature of our assets and the relatively slow depreciation profile they have means that delays now will make it harder to act in the long run interests of consumers in the future as changes accelerate.

In preparing this Final Plan we have reviewed the asset categories and asset lives currently applying for the DBNGP.

Asset categories

We have proposed eight regulatory asset classes with asset lives ranging from five years for computers and motor vehicles up to 70 years for pipeline assets. These categories better reflect the assets used to provide pipeline services and, consequently, will ensure that the capital base reflects the assets used to provide services. These categories also more closely align with those of other transmission pipelines.

The asset categories and asset lives we are proposing, and comparison to the asset categories and asset lives for other transmission pipelines, is outlined in more detail in Attachment 9.1.

Our proposed asset categories and lives are summarised in Table 9.4. Italicised elements represent new categories, while bold entries represent changes in asset lives, for example metering shifted from 50 to 30 years to align with similar assets on the Goldfields Gas Pipeline (the third column of which includes the implications of our analysis of the economic life of the DBNGP system as a whole, as described under in Asset Lives below).

Table 9.4: Proposed AA5 asset categories

Proposed category	Proposed asset life (years) - initial	Asset life (years) – capped
Pipeline	70	39
BEP asset account	57	39
Metering	**30**	**30**
Compression	30	30
Cathodic protection	*15*	*15*
SCADA ECI and communications	*10*	*10*
Computers and motor vehicles	*5*	*5*
Other depreciable assets	**10**	**10**
Non-depreciable assets	n/a	n/a

In addition to setting the proposed asset categorisation and lives for new capex in AA5, our proposal also adjusts the asset categorisation and lives for existing assets to determine the capital base as at 1 January 2021. This ensures similar assets are treated consistently in our asset base and to ensure that prices reflect efficient costs.

Overall economic life

The second change involves reconsidering the overall economic life of the pipeline system as a whole.

Because of the changes occurring in the energy sector, we believe that it is no longer appropriate to assume that each asset class has a life in years (eg, 70 years for pipelines) which does not change from one AA period to the next.

As alluded to above, two factors make this approach untenable:

- technological change, particularly in respect of renewable energy; and
- policy change in respect of decarbonisation.

Turning first to the direct impacts of technology. The issue is not renewable energy per se, but rather that the particular technologies being deployed (solar, wind, storage and hydrogen) are distributed energy technologies. The DBNGP has monopoly power today because most of the natural gas lies in the north of WA, and most of the demand for energy lies in the south, with the pipeline the conduit between demand and supply.

However, a distributed energy technology can be deployed anywhere, and at different scales. This makes for a fundamentally different market; we shift from a market where we are the sole transport option from the source of supply to the source of demand to a market where we act as the arbitrage agent for producers wishing to exploit geographical advantages such as relative amounts of sunshine or wind.

In an arbitrage market, as the average cost of production of renewable energy falls, the arbitrage opportunity also diminishes until it implies a transport price below a building block regulatory price. This likely outcome is equally applicable for current renewable electricity technologies, and future ones including green hydrogen (which we may, in theory, be able to transport).

Renewable technologies are currently relatively high in price compared to gas, but they are falling rapidly. Moreover, even at their current high price, they are starting to have impacts on our demand (See Chapter 11).

At present, this impact is associated with creating peaks in demand for our services as the weather changes (i.e. wind and sunshine). These peaks are often unpredictable, making actual transported volumes for gas-powered generation vary more widely from nominations on a day-to-day basis. However, in future, as battery storage moves further down the cost curve, we expect more fundamental effects on our overall demand as well. This is discussed in more detail in Attachment 9.2.

Secondly, in terms of indirect impacts, changes in emissions policy, wherever they occur, can directly affect our demand; a tightening of emissions standards in California, say, causes innovations in renewable power that are subsequently deployed globally. However, local policy has a direct effect; at its most extreme, a "net zero" emissions policy effectively puts an end date for the transmission of natural gas and, in the interim, emissions reductions targets put limits on the amount of gas consumers can efficiently use.

The Western Australian government, in a statement to Parliament on 28 August 2019, announced that it "is committed to working with all sectors of the Western Australian economy towards achieving net zero greenhouse gas emissions by 2050";[17] (see Attachment 9.2). While detailed policies to achieve this target have not yet been established, we believe that these policy settings will tighten in the decades ahead. This target suggests that in the absence of hydrogen being transported in the DBNGP at some point in the future (a prospect which is not without technical challenges), an economic life ending in 2050 would be aligned with policy.

Nonetheless, as an interim setting, our analysis that follows (and is detailed in Attachments 9.2 and 9.3) uses the current Federal Government target of a 28% reduction from 2005 levels by 2030 as our central assumption (and therefore reflects, in our view, a highly conservative assumption).

Due to both technological and policy pressures, we face the potential for significant future competition. We believe that this competition will overtake the regulatory constraint as the primary factor which binds our pricing.

[17] Parliament of Western Australia, *Parliamentary Debates*, Legislative Assembly, 28 August 2019, p5985 (The Hon Bill Johnston, MLA, Minister for Energy)

Given the long-lived nature of our assets, this requires us to act, much like any other business. The issue is how best to incorporate information we have about the future into robust action now.

As noted earlier, our concerns above are no different to those of our customers who indicated in our engagement activities that they are considering future energy delivery models in a carbon constrained environment. Customers recognise these issues in many of their public statements. For example:

> *"Overall, I think we do see a progressive decline in our carbon footprint."*[18]

> *"…we must take a coordinated, integrated and long-term approach to ensure that we meet Australia's international commitments to reduce emissions"*[19]

The Australian Energy Markets Commission (AEMC) provided some guidance on the need to consider the longer-term impacts of climate change policies and how the decisions made today can shape the future energy sector. In particular, they note that:[20]

> *"…making changes specifically to provide customers with short-term price decreases at the expense of enabling investors to recover a return on efficient investment will not be in the long-term interests of consumers if it results in generation retirement and power cuts that are more costly than the short term price savings"*[21]

To turn this guidance into a practical response, we have developed a model based on the Window Of Opportunity PaSt (WOOPS) framework developed by Crew and Kleindorfer (1992) with the assistance of ACIL Allen (See Attachment 9.5). This model deals specifically with the issue of changing depreciation when a monopolist faces future competitive threats from substitutes undergoing technological change.

The model uses predictions about the cost of renewable power in the future and, in particular, when it is likely to reach cost parity with delivered natural gas. It then checks to establish whether the regulatory regime prior to the point of parity and the competitive regime after that point combine to provide sufficient revenue to allow us to recover our investment on the DBNGP. Where it does not, small changes are made to the depreciation schedule until, at the new parity point, we are able to recover our costs over the whole economic life (that is, under regulation and competition) of the pipeline system. In simple terms, it provides a least-cost and efficient means of preventing asset stranding by the future competitive threat. Attachment 9.2 provides a detailed overview of the model. The expert report by ACIL Allen is included in Attachment 9.3. The model itself is provided in Attachment 9.5.

The model demonstrates that, under a set of assumptions that represent the mid-point of the various drivers in our forecasts, an overall economic life up to 2059 is appropriate in the regulatory model for the DBNGP. This creates a situation such that the revenues we can earn whilst regulation is the binding constraint and the revenues we can earn in in the competitive marketplace that follows are sufficient to allow us to recover our investment and to deliver a set of prices which has a minimum distortion to demand over the life of the pipeline system.

The outcomes of this analysis for regulatory depreciation are outlined in Table 9.6.

Table 9.5: Forecast regulatory depreciation 2021 to 2025 (nominal)

	2021	2022	2023	2024	2025
Straight line depreciation	140.5	132.9	138.3	142.2	147.4
Less inflation	40.0	39.3	38.6	37.7	36.8
Regulatory depreciation	100.5	93.6	99.7	104.6	110.6

[18] Synergy CEO, Jason Waters to the Parliament of Western Australia Standing Committee on Estimates and Financial Operations, 13 November 2018
[19] Alinta Energy Managing Director and CEO Jeff Dimery, in *Sustainability Report 2017/18*
[20] Australian Energy Market Commission, *Submission to the Climate Change Authority* on 23 August 2019
[21] AEMC Submission to the Climate Change Authority

Table 9.6: Forecast regulatory asset base 2021 to 2025 ($ mil Dec 2020)

	2021	2022	2023	2024	2025
Capital base at 1 Jan	3,357.3	3,259.7	3,166.0	3,054.9	2,950.2
Plus Conforming Capex	41.3	36.1	22.4	31.0	29.2
Less					
Disposals and redundant assets	-	-	-	-	-
Regulatory Depreciation	138.8	129.8	133.5	135.7	138.9
Capital base at 31 December	**3,259.7**	**3,166.0**	**3,054.9**	**2,950.2**	**2,840.5**

9.4.3 Inflation

Forecast inflation is used to adjust the capital base over the next AA period (in this case AA5). It is later updated for actual inflation when adjusting the capital base for the previous AA period (consistent with the adjustment to our capital base for actual inflation made now for the current AA period explained in Chapter 10).

Forecast inflation is also used in determining the total revenue that we can recover (and hence the prices we can charge). Under the methodology in the ERA's *Rate of Return Guidelines 2018*, forecast inflation applies to the following two costs:

- *return on capital* – which is calculated by multiplying a nominal rate of return (see Chapter 10) by the nominal capital base determined in this chapter (where a nominal value includes the impact of inflation); and
- *regulatory depreciation* – which is calculated by deducting from the forecast inflation adjustment applied to the capital base from forecast straight-line depreciation.

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

The ERA requires the application of the break-even approach to forecast inflation, which is also detailed in its Guidelines. This approach uses the difference between nominal and inflation-indexed Commonwealth Government bonds to derive a forecast of inflation.

This forecast is an annual inflation rate, for the five years of the AA period. The forecast will be made at the same time that the cost of debt and cost of equity are finalised, just before the Final Decision.

Applying the ERA's approach now to estimate inflation today provides an estimate of 1.19% per annum over AA5. This is a holding value; as with the risk-free rates for debt and equity (see Chapter 10), we have used a forward rate for the five years from 1 January 2021 formed during October 2019. We propose to use the on-the-day approach, as per the Guidelines, using an averaging period closer to the ERA's Final Decision.

Removing inflation from straight-line depreciation determined as above (see Table 9.6) gives regulatory depreciation as shown in Table 9.5.

9.4.4 Forecast closing capital base

The forecast roll-forward of our capital base over AA5, taking into account forecast depreciation, capex and inflation, is set out in Table 9.6. Our capital base declines, from $3,357 million as at 1 January 2021 to $2,840 million as at 31 December 2025.

9.5 Summary

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

Responding to the requirement in the NGR to consider the appropriate economic lives of assets and to the evolving energy marketplace, we have reviewed depreciation for the first time in almost 20 years.

We have drawn two conclusions from this review. Firstly, that we need to update our asset categories to reflect subsequent industry and regulatory practice over the past 20 years. Secondly, that we need to reconsider the overall economic life of the pipeline in a robust fashion. Our proposal suggests an economic life of the DBNGP as a whole up to 2059.

The value of our closing capital base is $2,840 million at the end of the next AA period, in dollars of December 2020.

10 Financing costs

We have set our financing costs in line with the ERA's Rate of Return Guideline, resulting in an estimated rate of return of 4.31%.

IN THIS CHAPTER

We have followed the ERA's Rate of Return Guidelines to estimate the rate of return

Based on forward market estimates, the rate of return is 4.31% (compared to 5.59% at the end of AA4)

We are expecting lower financing costs in AA5 compared to AA4, with the return on our investment falling by $187 million

Financing the $3.5 billion investment in the DBNGP is one of our largest costs.

Achieving a reasonable rate of return is essential in order to attract the necessary funding from our shareholders and debt providers so that we can continue to invest in our pipeline. We also estimate a regulatory tax allowance to cover the cost of tax over AA5.

The following sections outline how we have calculated our efficient financing costs in AA5. Our approaches are in line with the ERA's Guidelines,. All numbers quoted are in dollars of December 2020, unless otherwise labelled.

10.1 Regulatory framework

The NGR provide a framework for calculating the return on the projected capital base (rate of return).[22] The Guidelines[23] detail the ERA's preferred approach for calculating the rate of return under the NGR.

The Guidelines also outline the ERA's methodology for calculating the value of imputation credits (gamma) to equity holders, which is used to calculate the tax building block. We have applied the Guidelines to calculate our allowed financing costs.

10.2 Overview

Our financing costs account for around 30% of the building blocks that form our required revenue and prices. Financing costs represent the cost of financing our capital base and meeting our tax obligations.

Our forecast of total financing costs for AA5 is:

- $486 million in return on our capital base; and
- $52 million in cost of tax.

10.3 Customer and stakeholder engagement

We engaged with customers and stakeholders on the development of our financing costs.

During the Shipper Roundtables customers wanted to understand how we would develop our financing costs, specifically the rate of return. We indicated to customers that we would apply the ERA Guidelines before it was made final and presented our proposed approach (in line with the Guidelines) in the Draft Plan.

Customers were comfortable with our approach to apply the Guidelines and agreed this was appropriate for achieving our objective of submitting a plan that is capable of being accepted by our customers and stakeholders.

A summary of all customer and stakeholder feedback regarding our financing costs and how we have responded is summarised in Table 10.1.

[22] NGR87
[23] ERA 2018, *Final Rate of Return Guidelines (2018)*

Table 10.1: Customer and stakeholder engagement: financing costs

Topic	Customer and Stakeholder Feedback	Our Response
Financing Costs	**Stage 1 and 2 Engagement : Developing our Plans**	
	Customers were keen to understand how AGIG intends to calculate the rate of return.	• We advised that we have applied the ERA's *Rate of Return Guidelines* to calculate the rate of return to meet the objective of a plan capable of acceptance, noting the Guidelines had not been finalised when we provided this assurance in the Shipper Roundtable meetings. • In January 2019 we provided an estimate of 5.6% with a forward estimate of 5.99%, and then in March we updated the estimate to 5.39% (based on information available at the time).
	Stage 3 Engagement : Draft Plan Consultation • **Do you have any comments on our approach to setting the financing and tax costs in this Draft Plan?**	
	Customers acknowledged AGIG's intention to adopt the ERA's *Rate of Return Guidelines* in formulating its plans.	• We advised customers that applying the ERA's Guidelines is consistent with the approach taken for other AGIG assets, and that this is consistent with submitting a plan which is capable of being accepted by our customers and stakeholders.
	Stage 4 Engagement: Refining our Plans	
	No further feedback was received.	• In Shipper Roundtable 9 we provided updated building block calculations, including rate of return and tax allowances based on currently available information.
	Final Plan Outcome	
	• We have applied the ERA's *Rate of Return Guidelines* in this Final Plan, and this approach is supported by customers and stakeholders. • The rate of return applied in this Final Plan is 4.31%. • We have also updated our approach to calculating the tax allowance following the release of the ERA Final Decision for ATCO Gas. This had the impact of reducing allowed tax relative to the information provided to customers in October/November 2019.	

10.5 Return on assets

Our return on assets is determined based on an estimate of the return on equity and the return on debt to be incurred over AA5.

10.5.1 Return on equity

The return on equity reflects the return required by shareholders to invest in the pipeline. Unlike the return on debt, it is difficult to observe directly the return on equity required by shareholders in the market. This means we are required to use financial models and other market evidence to inform the estimate of the return on equity required by shareholders.

The ERA estimates the return on equity using the capital asset pricing model, which requires the following three parameters to be estimated:

- *the risk free rate* — which measures the return an investor would expect from an asset with no risk. It is estimated based on the interest rate on Australian Commonwealth Government bonds with a five-year term;[24]
- *the market risk premium (MRP)* — which reflects the expected return over the risk-free rate that investors require to invest in a well-diversified portfolio of risky assets;[25] and
- *equity beta* — which measures the sensitivity of an asset's returns relative to movements in overall market returns.[26]

In the Guidelines, the MRP and equity beta are fixed. The risk-free rate is estimated based on a 20-day window close to the time of the ERA's Final Decision. For the purposes of this plan, we have used the forward rate (calculated for the 20 trading days to 29 October 2019) for December 2020.

We recognise that the ERA uses an on the day rate, and not a forward rate in its Guidelines, and we propose to adopt this approach when the averaging period is chosen closer to the time of the ERA's Final Decision. The use of the forward rate is a placeholder that is intended solely to give our stakeholders a better indicator of what the rate might be in the Final Decision than the on-the-day rate in October 2019.

The indicative return on equity is 5.16%, as shown at Table 10.2.

Table 10.2: Indicative return on equity

Parameters	Value
Equity risk-free rate	0.96%
Beta	0.7
Market Risk Premium	6%
Return on equity	**5.16%**

10.5.2 Cost of debt

The cost of debt reflects the interest rate required by debt holders to invest in the pipeline. Much like the return on equity, the cost of debt comprises a base interest rate and a risk premium, in this case referred to as the debt risk premium (DRP). The approach for estimating the return on debt is also prescribed in the Guidelines.

The cost of debt is observable in the marketplace, and the ERA makes use of market data. It forms its cost of debt estimate by summing:

- the five-year swap rate chosen just prior to the Final Decision;
- an allowance for swapping and hedging (fixed at 0.21%); and
- an estimate of the premium above the ten-year swap rate of ten-year, BBB+ corporate debt, formed as a ten-year trailing average and estimated using the ERA's bespoke index methodology.[27]

As with the return on equity, the cost of debt allowance is finalised just prior to the ERA's Final Decision. Unlike the return on equity, it is updated annually for the trailing average DRP during the AA period.

Table 10.3: Indicative cost of debt

Parameters	Value
Debt risk-free rate	1.11%
Debt risk premium	2.28%
Debt raising costs	0.10%
Hedging costs	0.11%
Cost of debt	**3.61%**

Based upon data from October 2019, the indicative cost of debt for our Final Plan is 3.61% as shown in Table 10.3. As noted previously we

[24] Final Rate of Return Guidelines (2018), section 7
[25] Final Rate of Return Guidelines (2018), section 11
[26] Final Rate of Return Guidelines (2018), section 12
[27] Final Rate of Return Guidelines (2018), section 6

have used a forward swap rate (calculated in October 2019) for December 2020 for debt.

We have also made a forecast for the debt risk premium for the 2021 tranche of debt based upon an average during AA4. As with equity, this is to provide stakeholders with an indication of what these numbers might be at the time of the Final Decision. We propose to use on-the-day numbers chosen during an averaging period close to the ERA's Final Decision, as per the ERA's Guidelines.

10.5.3 Rate of return

The ERA assumes gearing of 55%. This means it is assumed 55% of our total capital base is financed by debt, with the remaining 45% being equity.[28] Applying these percentages to the return on equity (5.16%) and cost of debt (3.61%) results in an overall rate of return of 4.31% over AA5, as shown in Table 10.5.

Table 10.5: Indicative rate of return

Parameters	Value
Return on equity	5.16%
Cost of debt	3.61%
Gearing	55%
Rate of return	**4.31%**

Table 10.4: Roll forward of the tax asset base ($million, nominal)

	2021	2022	2023	2024	2025
Opening tax asset base	946.2	884.7	814.0	725.6	644.3
Plus gross capex	41.8	37.0	23.2	32.5	30.9
Less tax depreciation	103.3	107.6	111.5	113.8	117.3
Closing tax asset base	884.7	814.0	725.6	644.3	558.0

10.6 Cost of tax

Our tax costs are based on an assessment of our taxable income, the applicable corporate tax rate and the value of imputation credits (gamma) to equity holders.

10.6.1 Calculating the tax allowance

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

- *total revenue* — which is the sum of all of our costs (or building blocks) aside from the cost of tax (see Chapter 13);
- *opex* — which is a specific building block reflecting our efficient operating expenses that is used to determine total revenue (see Chapter 7);
- *tax depreciation* — which is based on the calculation of the tax asset base in any particular year (refer Section 10.5.3); and
- *interest expense* — which is determined by multiplying the cost of debt (of 3.61%) by 55% of our capital base in each year, reflecting the debt funded proportion of the total capital base (see Chapter 9).

The corporate income tax rate is set at 30% consistent with the prevailing corporate tax rate applying in Australia, as per the ERA's requirements. This is then applied to taxable income to obtain a cost of tax.

This cost of tax is then multiplied by gamma, which represents the value of imputation credits. This gives the value of the tax allowance which we are able to recover.

In the ERA's Guidelines, gamma is set at 0.5. This has the effect of halving our tax allowance.

[28] Final Rate of Return Guidelines (2018), section 5.1

10.6.2 Tax depreciation

Tax depreciation is used to determine the estimate of taxable income and to update the value of our Tax Asset Base (TAB), as discussed in Section 10.5.3. Our approach to determining tax depreciation in this Plan has changed compared to our previous AAs.

This change is a result of the ERA's Final Decision for ATCO Gas Australia dated 15 November 2019. In it, the ERA gave effect to two key changes, being:[29]

- the use of 20-year tax asset lives (we already use a 20-year tax asset life which has been accepted in previous AA reviews); and
- the use of a diminishing value method (rather than a straight-line method) to calculate tax depreciation over those 20 years.

These changes, to the extent that they were not previously used by the business, apply to new assets only, as tax law does not allow for changes in depreciation approaches mid-stream.

These changes to tax depreciation reduce the tax allowance by roughly $10 million over AA5.

10.6.3 Tax asset base

The opening TAB of $946 million as at 1 January 2021 has been adjusted for the same forecast of capex used to determine the capital base (see Chapter 9) plus capital contributions received (as per the ERA's approach), and a forecast of tax depreciation over AA5 (see Table 10.4).

Table 10.6: Total tax allowance ($million, Dec 2020)

	2021	2022	2023	2024	2025
Gross estimated tax cost	23.2	21.3	19.4	21.9	22.4
Less imputation credits	11.6	10.7	9.7	10.9	11.2
Tax allowance	11.6	10.7	9.7	10.9	11.2

10.6.4 Tax allowance

Using the above information, the tax allowance to be recovered in AA5 is summarised in Table 10.6. The gross tax allowance is the corporate tax rate multiplied by taxable income.

10.7 Summary

A summary of our key financing cost parameters, developed in accordance with the ERA's Rate of Return Guidelines, is provided in Table 10.7.

Table 10.7: Summary of financing cost parameters

Parameters	Value
Return on equity	5.16%
Return on debt	3.61%
Overall rate of return	4.31%
Gamma	**0.5**

[29] ERA 2019, *Draft Decision on Proposed Revisions to the Mid-West and South-West Gas Distribution Systems Access Arrangement for 2020 to 2024*, s719-729

11 Demand

We forecast contracted capacity in AA5 to be 647TJ on average, per day, on a Full Haul equivalent basis. We are forecasting a decrease in contracted capacity in both Full Haul and Part Haul, and an increase in Back Haul compared to levels in AA4.

IN THIS CHAPTER

Our demand forecast considers the contracts and activities of our shippers (bottom-up) as well as overall changes in the WA gas market (top-down)

Full Haul demand on the DBNGP is decreasing in AA5 and we are seeing an increase in demand for Back Haul services

Demand for our services is a key input in calculating reference prices.

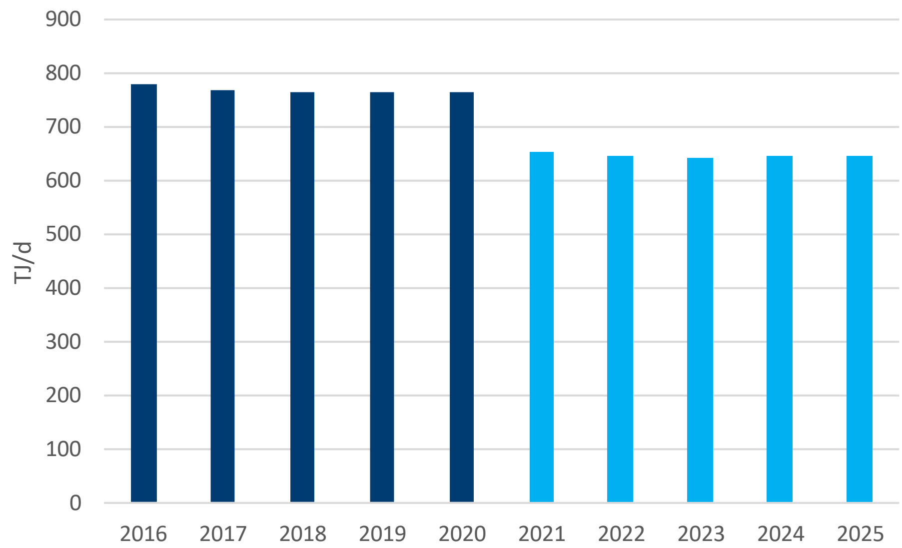
The following sections outline our approach to forecasting demand, comprised of contracted capacity and throughput (volume of gas transported).

11.1 Regulatory framework

Our AA proposal is required to include a forecast of contracted capacity and throughput over the AA5 period for each of the three reference services. This is a key input in determining our prices. Our forecast must:[30]

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

Figure 11.1: Actual (dark blue) and forecast (light blue) average Full Haul equivalent contracted capacity to 2025



11.2 Overview

The energy market in Western Australia is changing. Electricity

[30] NGR 74(2)

sourced from renewable sources such as wind and solar is displacing electricity generated from natural gas. This is being observed in the South West Interconnected System (SWIS), where a significant share of electricity demand in the SWIS is being met by renewable sources, with strong growth in rooftop solar.[31] Major industrial and mining shippers (see for example Fortescue Metals Group, which is seeking to source 60MW of power for its mining operations from solar power[32]) are also seeking to reduce their carbon footprint by sourcing more of their electricity from renewable sources. This was borne out in our Shipper Roundtable discussions, and is also reflected in the most recent Gas Statement of Opportunities (GSOO), which shows a drop in gas demand in the SWIS in 2021 similar to that which is in our forecasts, due primarily to increases in wind and solar power.[33]

Furthermore, the Western Australian government recently announced a target to achieve net zero emissions in the state by 2050.[34]

All of the factors outlined above demonstrate that the ongoing trend of greater reliance of renewable electricity will continue throughout AA5 and beyond.

Further, new production sources of natural gas are enabling other pipelines to be used to transport gas instead of the DBNGP.

The result is that demand on the DBNGP is changing. Our forecast average Full Haul equivalent contracted capacity over 2021-25 is 647TJ/day. This is a 16% reduction compared to the current 2016-2020 period, driven by shippers electing to reduce their over-contracted capacity to required levels (Figure 11.1).

Our forecast average Full Haul equivalent throughput over the AA5 period is 584TJ/day. This is a 9% reduction compared to the AA4 period and reflects the capacity relinquishment and use of other pipelines.

The sections below provide greater detail as to how the energy market changes are impacting the demand on the DBNGP (11.4) and our forecasting approach (11.5)

Reviewing our demand forecasts

We have undertaken two reviews of our forecasts of demand, which as described in Section 11.6 are based on indications from customers to AGIG on their requirements for the AA5 period, on top of publicly available information.

The first of the reviews was a “Reasonable Assurance Report”, conducted by KPMG under the ASAE 3000 (see Attachment 11.1). This was requested by customers as part of our stakeholder engagement program. Customers understand that we cannot share their commercially sensitive information in a public forum, and thus we undertook the review with KPMG. The review did not seek to make its own predictions, but rather relied upon the same information as that being used by AGIG. KPMG assessed whether that information was used to produce robust forecasts of demand.

The second was a top-down review by ACIL Allen (see Attachment 11.2). ACIL Allen looked first at our throughput forecasts and compared them with AEMO’s Gas Statement of Opportunities (GSOO). ACIL Allen then addressed the question of how shippers might behave in contracting capacity given spare capacity in our pipeline, and the economic conditions each shipper faces; that is, do they reduce the “insurance” value of contractual capacity and make use of other means of gaining access to required capacity on peak days or not?

In both cases, the consultants supported for forecasts.

11.3 Customer and stakeholder engagement

We engaged with customers and stakeholders on the development of our demand forecast.

During Stage 1 of engagement, and specifically at the Shipper Roundtables, customers noted they were experiencing an increase in the penetration of renewable electricity in the energy market. Customers were considering the implications of these changes for their business models, even before any specific commitment to achieving net zero emissions was announced by the Western Australian Government.

Customers noted they were keen to understand how the transformation

[31] See for example https://www.abc.net.au/news/2019-12-01/rise-of-rooftop-solar-power-jeopardising-wa-energy-grid/11731452
[32] https://www.smh.com.au/business/companies/hello-sunshine-fmg-mines-to-reach-100-per-cent-renewable-power-20191018-p531xf.html
[33] See https://aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/WA_GSOO/2019/WA-Gas-Statement-of-Opportunities---December-2019.pdf p22
[34] See https://www.mediastatements.wa.gov.au/Pages/McGowan/2019/08/State-Government-details-emissions-policy-for-major-projects.aspx

of the energy sector would be incorporated into our demand forecasts.

Our Draft Plan outlined our forecasts incorporating our expectations at the time for contracted capacity and throughput. Customers wanted to understand how our forecasts aligned with the Gas Statement of Opportunities (GSOO) and Electricity Statement of Opportunities (ESOO). We noted these external forecasts are used to inform our own forecast for the DBNGP. However, our forecasts ultimately reflect confidential information provided by shippers on their requirements on the DBNGP over AA5.

Following the Draft Plan, shippers requested more information about our demand forecast while recognising the importance of maintaining confidentiality. To this end, we engaged KPMG to conduct a Reasonable Assurance Review of our demand forecast to verify that it was based on the most recent information available. This report was made available to shippers. Attachment 11.1 explains the information that was provided and the sources of that information for that review, noting that the Final Plan forecast is consistent with that reviewed by KPMG.

A summary of all customer and stakeholder feedback regarding demand and how we have responded is summarised in Table 11.1.

Table 11.1: Customer and stakeholder engagement: demand

Topic	Customer and Stakeholder Feedback	Our Response
Demand	**Stage 1 and 2 Engagement : Developing our Plans**	

	- Customers and stakeholders are seeing an increase in renewable electricity in the energy market.
	- Customers noted uncertainty about the ongoing role of the DBNGP as the energy system decarbonises, and the related focus on renewable electricity.
	- Customers were keen to understand the assumptions underpinning our demand forecast in AA5.
		- We discussed our approach to forecasting demand at Shipper Roundtables 4 and 5, including overviews of:
		  - market supply and demand;
		  - throughput and end-use by industry sector for 2018;
		  - the diversification of current and future supply (e.g. Wheatstone);
		  - the current and forecast fuel mix, noting increasing renewable electricity generation facilities in the South West Integrated System (SWIS).
		- We presented a Full Haul equivalent demand forecast averaging 691 TJ/Day in January 2019.
		- We updated our forecast to an average of 682 TJ/ Day in March 2019 based on updated information that was available.
		- We forecast decreasing Full and Part Haul demand and increasing Back Haul Demand in AA5.

	Stage 3 Engagement : Draft Plan Consultation - **Do you support our approach to forecasting demand?** - **Are there any other factors you think we should consider?**	
	- Customers want to better understand how we have forecast demand and how this compares to the Gas Statement of Opportunities (GSOO) and Electricity Statement of Opportunities (ESOO). - Customers requested information on the sources of generation in the SWIS used for the demand forecast. Information was also requested on the historical use and future forecasts of SUG.	- We provided further information to customers on the methodology to forecasting capacity, highlighting that there are a number the factors (e.g. relinquishments) that need to be considered when comparing and attempting to reconcile the GSOO and ESOO with our forecast demand for AA5. - We committed to looking for a way to provide a greater level of assurance in our demand forecast without providing detail that would compromise customer confidentiality.
	Stage 4 Engagement: Refining our Plans	
	- Customers requested more detail on our demand forecast, while recognising the need to maintain confidentiality for individual Shipper forecast demand information supplied to AGIG.	- We engaged KPMG to undertake a Reasonable Assurance Review to provide an independent assessment of our demand forecast, including our forecast contracted capacity and throughput for reference services during AA5. - The Reasonable Assurance Review report was made available to all customers by KPMG and is included at Attachment 11.2 of the Final Plan. - We also held a teleconference with interested customers in October 2019 to respond to any queries or questions in relation the Review and our Demand Forecast for AA5.
	Final Plan Outcome	
	- Our approach to developing the demand forecast in AA5 is supported by customers. - We have provided additional informational to customers by providing an independent assurance that our forecasting methodology is reasonable, accurate and representative of the best forecast or estimate possible in the circumstances.	

11.4 Changing demand on the DBNGP

There are two key factors affecting the transportation of gas on the full length of the DBGNP:

- growth in renewable electricity generation; and
- new sources of gas production using alternative pipelines to the DBNGP.

The current and ongoing growth of renewable electricity (wind and solar) in the SWIS displaces electricity generated from natural gas.

The Electricity Statement of Opportunities (ESOO), which noted that electricity consumption had started to drop in 2019 and that peak demand (which is already 750 MW lower than in 2013) is likely to drop a further 200MW by the end of the next decade due to increased solar. It noted also that, by 2026, solar PV penetration will likely cause the lowest system demand to be 100MW (roughly one of Synergy's Kwinana turbines) down from a projection of 600MW in 2022. Furthermore, the number of hours that the market would spend below its 700MW threshold would rise 15-fold from 10 to 150.[35]

Renewable electricity has an influence on both the quantum of gas demanded on average through the year, and on the pattern of demand. As renewable electricity penetration increases, less gas is demanded in aggregate. However, the demand that does eventuate tends to be more volatile – that is when renewable electricity drops away due to its intermittency, the electricity demand is met by other forms of generation, namely natural gas. In these instances, actual gas demanded of the DBNGP increases significantly over a short period of time.

In response to the above market dynamics, shippers have told us they no longer require the same level of contracted capacity on the DBNGP as in AA4.

So while all of the physical assets associated with the pipeline are still required, they are not required for as long as they were previously.

Our forecast of throughput is therefore affected by the expected utilisation outlined above, but also by the use of the Parmelia Gas Pipeline (PGP) to bring gas to the SWIS. Specifically, this reflects new gas production from the Perth Basin which will have connections with both the DBNGP and PGP.

[35] See https://www.aemo.com.au/-/media/Files/Electricity/WEM/Planning_and_Forecasting/ESOO/2019/2019-WEM-ESOO-report.pdf

11.5 Demand during AA4

Table 11.2, Table 11.3 and Table 11.4 below outline daily average demand during AA4 for our full haul, part haul and back haul services respectively. The data is aggregated in accordance with rule 43(2).

Table 11.6 and Table 11.5 contain the number of shippers per inlet point and the number of shippers per outlet point, aggregated in accordance with rule 43(2).

Table 11.2: Full haul demand 2016 to 2019 (TJ)

	2016	2017	2018	2019	2020
Maximum	703.2	703.4	688.2	687.5	621.6*
Daily Average	620.2	610.6	614.2	618.0	621.6*
Minimum	479.6	509.5	511.6	544.2	621.6*

Table 11.3: Part haul demand 2016 to 2019 (TJ)

	2016	2017	2018	2019	2020
Maximum	168.1	182.7	175.8	166.3	124.4*
Daily Average	109.4	119.4	124.4	124.4	124.4*
Minimum	67.2	72.9	84.1	70.0	124.4*

Table 11.4: Back haul demand 2016 to 2019 (TJ)

	2016	2017	2018	2019	2020
Maximum	209.6	215.8	233.8	300.3	187.4*
Daily Average	187.4	187.3	187.3	187.3	187.4*
Minimum	91.9	115.3	101.9	101.6	187.4*

* NB 2020 values for Tables 11.2, 11.3 and 11.4 are forecasts of average demand. We do not forecast maximum and minimum demand.

Table 11.6: Number of shippers by inlet point

Inlet point	Number of Shippers
DDR	31
Pluto	12
MLV7 Interconnect	22
Devil Creek	28
Gorgon	27
Macedon	28
Wheatstone	24
Varanus Island	28
Mondarra	8

Table 11.5: Number of shippers by inlet point

Outlet point	Number of Shippers
Full Haul	8
Part Haul	18
Back Haul	18

11.6 How we develop our forecasts

We have been through an extensive process to determine our forecast of demand for AA5. This has included internal examination of our contracts, consideration of third party data sources like AEMO's Gas Statement of Opportunities (GSOO), discussions with shippers, and two external reviews of our forecasts.

- A review by KPMG of the process by which we developed our forecast.
- A review by ACIL Allen against public information and economic principles to determine the robustness of our forecasts.

The results of these reviews are shown in the box above.

11.6.1 Contracted capacity forecasts

Contracted capacity has traditionally been predictable and stable. Our T1, P1 and B1 negotiated pipeline services each require a 15-year commitment to an agreed amount of capacity, expressed as an amount of TJ per day. We examine the termination dates, capacity relinquishment rights and contracted capacity for each customer to develop an initial index of existing customer contracted capacity.

Secondly, for each of our customers, we compare the throughput forecast (described in the next section) to the capacity forecast developed for the customer.

Our forecast of throughput will be lower than the forecast of contracted capacity for each customer as overrun charges apply where actual throughput exceeds contracted capacity.

11.6.2 Throughput forecasts

Our throughput forecast is a forecast of energy delivered (in TJ) under a particular service on an average daily basis.

There are a number of sources of information that have been relied on to derive the forecast. Firstly, we maintain records for each of our customers' throughput within our Customer Reporting System (CRS) database. We use the CRS database to calculate average annual throughput levels and historical annual changes in throughput for each of our current customers and end-user industry groups. This data analysis is a key input to the throughput forecast.

Secondly, as with our forecast of contracted capacity, we rely on confidential information received directly from our shippers about their intended future use of our customers.

Thirdly, we also use a range of external data sources in developing forecasts of average annual throughput. We use a comprehensive range of external sources, including:

- the AEMO's GSOO;
- the AEMO's Electricity Statement of Opportunities;
- Department of State Development reports;
- submissions made to the ERA;
- local news articles about investment plans;
- the ABS; and
- Chamber of Minerals and Energy annual resources and economics reports.

As a final step, we compare the forecast of annual average throughput for each customer against actual historical throughput profiles. This is relevant for those shippers who have advised no change in their expected gas transportation requirements of the DBNGP.

The above process is a bottom-up, internal process, but we have also asked ACIL Allen to undertake a top-down assessment of our throughput and capacity forecasts. This is contained at Attachment 11.2, and provides further support as to the reasonableness of the forecasts. In particular, ACIL Allen note:

- That our capacity forecasts are in line with their top-down model of optimal contracting behaviour on the part of our shippers, given forecast market conditions.
- That our throughput forecasts are in line with past actual throughput and independent forecasts from AEMO, once changing market conditions are taken into account.

11.7 Forecasts by reference service

Forecasts of both capacity and throughput through AA5 are provided in Figures 11.2 (full-haul), 11.3 (part-haul) and 11.4 (back-haul). They reflect the outcomes of the analysis described above. In general, there is very little change during AA5.

In respect of capacity, the one major change occurs with full-haul capacity which we expect throughput to increase from October 2022. The staged retirement of Muja Power Station's two C units, as announced by the state government in August 2019,[36] is expected to increase demand for natural gas as additional sources of dispatachable electricity supplies are sought. This also has an impact on throughput.

Part and back-haul capacity nominations change very little, with the small changes seen being a function of a change in operations at one shipper, and another shipper shifting from part to back-haul.

Throughput forecasts, apart from the point noted above in respect of Muja C, show a slight decline through the period which is associated mostly with operational requirements, with some effects associated with wind and solar penetration, which is picking up a lot of the new electricity demand in the SWIS.

Figure 11.2: Forecast Full Haul demand in AA5

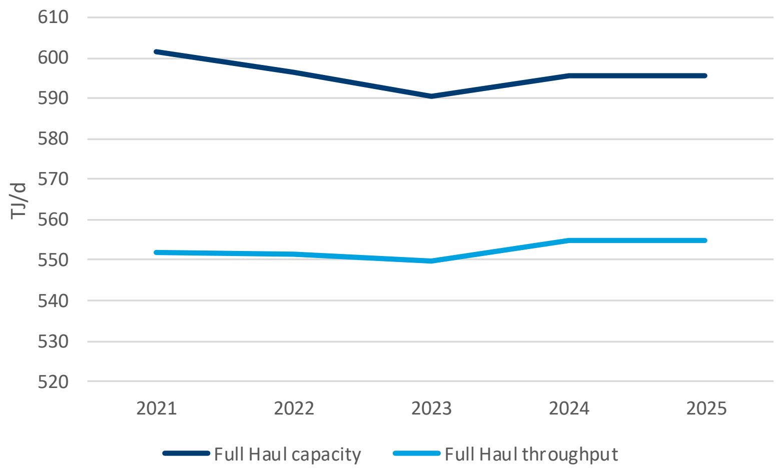


Figure 11.3: Forecast Part Haul demand in AA5

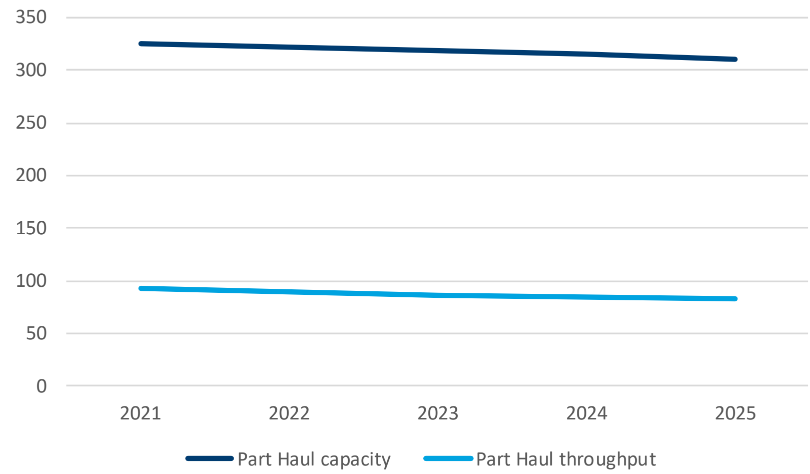
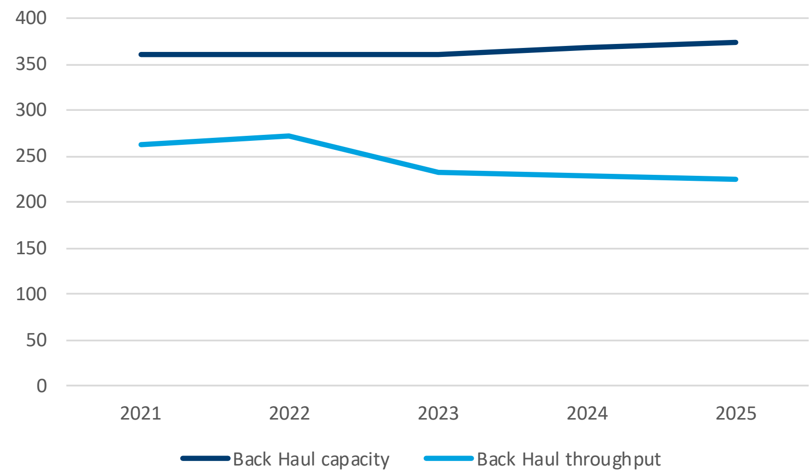


Figure 11.4: Forecast Back Haul demand in AA5



[36] See https://www.mediastatements.wa.gov.au 2022.aspx

11.8 Summary

We have forecast average daily contracted capacity in AA5 to be 647TJ/day on a full haul equivalent basis, which is 16% lower than the contracted capacity in AA4. This represents a decrease in contracted capacity in both Full Haul and Part Haul, offset by an increase to Back Haul when compared to levels in AA4.

The decrease compared to AA4 reflects the significant change occurring in the Western Australian energy market. Renewable electricity penetration grew rapidly over AA4 and will continue over AA5,[37] thereby displacing electricity generated from natural gas. Further, with the development of new gas producing basins, another pipeline other than the DBNGP can be used to bring gas to Perth.

Our forecasts have been subject to two external reviews and are supported by customers. We consider the demand forecast is arrived at on a reasonable basis and represents the best forecast possible in the circumstances.

[37] See https://www.aemo.com.au/-/media/Files/Electricity/WEM/Planning_and_Forecasting/ESOO/2019/2019-WEM-ESOO-report.pdf

12 Incentives

We are proposing an opex incentive scheme in AA5. The Efficiency Factor (or E Factor) scheme will strengthen our incentive to deliver operating cost savings and efficiency improvements, and allows benefits to be shared with our customers.

IN THIS CHAPTER

We propose an opex incentive scheme (the Efficiency Factor) in AA5 to strengthen our incentives to incur efficient opex

We have decided against proposing an innovation scheme, capex scheme or customer service scheme on the basis that customers did not support either at this time

We support effective, outcome-based incentive arrangements as a way of more actively promoting the long-term interests of our customers.

In AA5 we are proposing to introduce the E Factor. The E Factor is an opex incentive scheme that offers rewards to DBP for achieving efficiency gains (opex savings), and penalties for efficiency losses (opex overspends). Importantly, the E Factor allows us to share with our customers the majority (more than 70%) of any benefits achieved, leading to a lower opex cost base and driving lower pipeline tariffs over time.

The E Factor only applies to opex. During the development of our Draft Plan and this Final Plan, we considered adopting a capex efficiency scheme similar to that recently introduced by the AER. However, customers did not support this on the basis that our annual stay-in-business capex is relatively small – around 1% of the total value of our capital base – therefore any capex gain or loss would be minimal. A capex efficiency scheme is therefore unlikely to significantly increase incentives above those that already exist.

We also looked at a customer service incentive scheme, and an innovation scheme. However, as with the capex scheme feedback from customers indicated they do not support these types of incentives at this time. We are therefore not pursuing them for AA5.

This section explains how the E Factor works. The proposed formulae and carryover mechanisms that allow any increments or decrements in total revenue in the next period are defined in the proposed access arrangement document that accompanies this Final Plan (see part 16 of the Access Arrangement).

12.1 Regulatory framework

A key requirement of the National Gas Objective (NGO) is for the regulatory framework to promote efficient investment in and operation and use of gas pipelines.

In support of this requirement, the NGR provides that an AA may include (or the ERA may require it to include) one or more incentive mechanisms to encourage efficiency in the provision of services. This includes promoting:[38]

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

An incentive mechanism must also be consistent with the Revenue and Pricing Principles in the NGL (NGR, rule 98(3)).

Furthermore, our Final Plan should include the proposed carryover of the amounts and a demonstration of how any allowance is to be made in the value of total revenue for those amounts.[39]

12.2 Overview of incentives

Regulators use incentive mechanisms to:

- strengthen incentives for businesses to find sustainable cost reductions and ongoing efficiencies;
- smooth incentives across the years of a regulatory period; and
- ensure the benefits of efficiency improvements are shared with customers.

Outside of Western Australia regulated gas and electricity businesses have been operating under opex incentive mechanisms for some time, with the primary scheme being the AER's Efficiency Benefit Sharing Scheme (EBSS).

In Western Australia, the ERA applies an opex scheme (the Gain Sharing Mechanism (GSM)) to Western Power, but no equivalent opex incentive mechanisms currently apply to DBP. DBP was formerly subject to a reward-only opex incentive scheme called an Efficiency Carryover Mechanism, however this scheme fell away when regulation moved from the Western Australian Gas Code to the NGL and NGR in 2009.

We have engaged with our customers (primarily gas shippers) on the potential merits of an opex incentive mechanism, and believe the time is right to reintroduce a suitable opex scheme for DBP. Adopting an opex scheme for AA5 will provide a stronger incentive to improve efficiency, in addition to the incentives already provided.

The opex incentive scheme we propose is specifically designed to provide value for DBP and, more importantly, Western Australian customers. While elements of the E Factor are similar to the AER's EBSS, the design of the scheme, including the various inclusions and exclusions, is more akin to the ERA's GSM.

To ensure the integrity of the incentive scheme and avoid windfall gains (or losses), we have designed the E Factor such that it does not apply to costs that are outside of our control, or are forecast by means other than the base year roll-forward approach.

The E Factor is consistent with the Revenue and Pricing Principles in the NGL because it provides an effective incentive for DBP to reduce operating costs, balance potential capex bias and promotes economic efficiency.

More detail on the E Factor is included in Attachment 12.2.

12.3 Customer and stakeholder engagement

During the Shipper Roundtables we discussed potential incentive schemes to apply in AA5.

Shippers told us they were broadly comfortable that the current framework incentivises us to incur only efficient costs. However, price is important to shippers and, given the quantum and recurrent nature of opex, they could see the benefits of strengthening the incentive for delivering efficiency improvements. Customers did not support a capex incentive scheme.

In the Draft Plan we outlined an opex incentive scheme and that we are still seeking stakeholder views on an innovation incentive scheme.

Following the Draft Plan several customers took interest in how the benefits sharing aspect of the E Factor scheme would work, and they were generally comfortable with the concept that DBP should not be rewarded or penalised for variations in costs that are outside of its control.

For innovation, customers noted they expect our business to play a role in supporting renewable electricity technologies, meeting renewable energy and emissions targets, and decarbonising energy supply. However, customers had mixed views on the introduction of an innovation incentive scheme

[38] NGR 98
[39] NGR 71(1)(i)

in AA5 and many felt these were not required at this time.

For an innovation scheme, customers felt benefits would likely be greater under a whole of industry approach to innovation.

Taking this feedback into account, the new E Factor opex scheme is the only incentive mechanism we propose to introduce for AA5.

A summary of all customer and stakeholder feedback regarding incentives and how we have responded is summarised in Table 12.1.

12.4 The E Factor

The E Factor is similar to the GSM applied by the ERA to Western Power, and the EBSS applied by the AER to electricity and gas businesses. It provides a continuous incentive for DBP to achieve efficiency gains, regardless of the year that an efficiency gain is achieved.

In the absence of a scheme, the incentive to reduce opex may decrease as the regulatory period progresses. This is because the period by which the business retains the benefit of an efficiency gain decreases.

More detail on the E Factor proposal is included in Attachment 12.2.

The E Factor establishes an annual opex benchmark. Each year, if we are able to outperform the benchmark (spend less than the target), we will be allowed to retain a portion of the saving (which is equivalent to retaining that gain for five years, and is referred to as an efficiency gain), with the other portion (more than 70%) returned to customers via a tariff revenue adjustment.[40]

To ensure the incentive to outperform the opex benchmark is even in each year of a regulatory period (and spans between access arrangement periods), the incremental efficiency gains or losses are carried forward for five years. Therefore, there is no revenue impact until the next AA period (AA6, 2026-2030).

[40] The 30:70 split is based on a real discount rate of 6% over a 30-year NPV analysis.

Table 12.1: Customer and stakeholder engagement: incentives

Topic	Customer and Stakeholder Feedback	Our Response
Incentives	**Stage 1 and 2 Engagement : Developing our Plans**	
	• Customers support a focus on innovation to ensure the products and services we offer are responsive to the needs of our customers, and the changing dynamics of gas supply. • Customers highlighted the importance of flexibility to respond to their needs. • Customers noted that price is important and they could see potential benefits in strengthening our incentives for efficient opex. • Customers supported innovation, particularly for renewable energy. • Customers did not indicate support for a CESS or a customer incentive scheme.	• We discussed potential incentive arrangements for opex, capex, service performance and innovation. • In March we presented our plans to only propose an opex and innovation scheme based on feedback received to that point.
	Stage 3 Engagement : Draft Plan Consultation • **Do you support our proposal to introduce an opex efficiency benefit sharing scheme (EBSS)?** • **Are there any additional considerations that should be incorporated into an opex EBSS?** • **Do you support our proposal to introduce an innovation scheme?** • **Are there any additional considerations that should be incorporated into an innovation scheme?** • **What level of allowance should be allowed under any proposed innovation scheme, and what type of innovation projects should be in scope?**	
	• Customers supported an opex EBSS in AA5. • Customers did not support an innovation or capex incentive scheme applying in AA5.	• At Shipper Roundtable 8 we further discussed an opex EBSS in more detail, including the design basis and an example of how the proposed scheme could work in practice.
	Stage 4 Engagement: Refining our Plans	
	• Customers sought assurance that the proposed scheme would include both rewards and penalties. Customers also wanted to understand the mechanics as to how the rewards and penalties are determined.	• We provided an example model to customers for their review and consideration. The proposed scheme includes both rewards and penalties.
	Final Plan Outcome	
	• Price is important to our customers and we have customer support for strengthening our incentives for efficient opex. • Our proposal to introduce an opex incentive scheme in AA5 is supported by customers and stakeholders. • We haven't included an innovation, capex or a customer incentive scheme in our proposal in AA5, as these were not supported by customers.	

12.5 Summary

We engaged with our customers about incentives, and although they were broadly comfortable that the current framework incentivises efficient costs, they supported strengthening our incentives to incur efficient opex given its quantum and recurrent nature.

Our customers recognised a capex , innovation and customer service incentive could both facilitate better outcomes over the long term. However, it was clear that they did not support the introduction of a dedicated scheme for capex, innovation or customer service for our business in AA5.

Therefore we have proposed only the E Factor scheme for AA5, which provides strengthened incentives to seek efficiency improvements throughout AA5, and allows these benefits to be shared with customers.

13 Revenue and Pricing

IN THIS CHAPTER

Revenue reduction of $241 million (or 13%) compared to AA4.

Full Haul reference price of $1.43 per GJ (before inflation), a 4% increase compared to the current reference price and 6% below our 2014 negotiated prices

Our proposed revenues are 13% lower than forecast AA4 revenues. Changes in demand and pipeline use drives a 4% increase in reference prices, but overall customers are paying less.

Our Final Plan delivers a revenue reduction of $241 million, and therefore overall savings to our customers in AA5.

Our costs are referred to as building blocks and are summed to determine total revenue in each year of the AA period (referred to as building block total revenue). We recover this revenue through the prices that we charge customers for providing services.

This section sets out the total revenue we require over AA5 and how we will recover this through our reference service prices.

13.1 Regulatory framework

We are required to determine total revenue for each year of AA5 as the sum of our forecast opex (Chapter 7), return on our capital base (Chapters 8, 9 and 10), depreciation of the capital base (Chapter 9) and a forecast of the tax allowance (Chapter 10).

Our prices are required to reflect the efficient cost of providing services to our customers, and this underpins the ERA's assessment of all aspects of our Final Plan.

13.2 Customer and stakeholder engagement

We engaged with customers and stakeholders on the development of our revenue and pricing proposal.

Price is a key factor for our customers, alongside safety and reliability.

During Stage 1 of engagement we discussed how our costs are currently allocated across reference services. We explained that Part and Back Haul prices are calculated using a distance factor of the Full Haul price, whereas alternative options include zone based or postage stamp pricing.

Customers were comfortable with our approach to maintain the current cost allocation between Full, Part and Back Haul reference services based on distance factors.

Our Draft Plan presented customers with the building block revenue and price based on various assumptions at the time. The Draft Plan included a $130 million reduction in revenue, resulting in a price of $1.40 per GJ.

Following publication of the Draft Plan we presented further updates to the building blocks and price at Shipper Roundtables 6 to 9.

A summary of all customer and stakeholder feedback and how we have responded is summarised in Table 13.1.

Table 13.1: Customer and stakeholder engagement – Revenue and prices

Topic	Customer and Stakeholder Feedback	Our Response
Revenue and prices	**Stage 1 and 2 Engagement : Developing our Plans**	
	• Reliability and price are two of the most important considerations for customers and are often raised together. • Customers were keen to understand the price impact of our proposals.	• We provided information to customers during Shipper Roundtable Meetings 1 and 2 including an overview of how our prices are determined using the regulatory building blocks. • We also adopted an approach to cost allocation consistent with that accepted in AA4. • We adopted a transparent approach to informing customers of the price impacts of our proposals, including regular updates to the regulatory building blocks and resultant prices for almost 12 months prior to submission of our Final Plan. • Our Draft Plan presented customers with the building block revenue and price based on various assumptions and our proposals at the time. It included a $130 reduction in revenue, resulting in a price of $1.40 per GJ.
	Stage 3 Engagement : Draft Plan Consultation • **Have we provided enough information to understand the basis of our proposed price, including how it is split between the capacity and commodity components?** • **Is there anything that our Draft Plan hasn't considered that is important to you?**	
	• Customers requested further information on cost allocation between fixed and variable costs and between different services.	• We explained that Part and Back Haul prices are calculated using a distance factor of the Full Haul price. • We provided further explanation on our approach to adjusting the split between the capacity and commodity components of our price
	Stage 4 Engagement: Refining our Plans	
	• Customers wanted to be continually updated on our proposed price.	• We continued to provide building block and price updates to Shipper Roundtable members as we developed our Final Plan.
	Final Plan Outcome	
	• We have delivered a revenue reduction of $241 million. • Our Final Plan outlines further information on cost allocation and adopts an approach consistent with the approach accepted in AA4.	

13.3 Revenue

Previous chapters in our Final Plan set out the basis of all the relevant building blocks that are used to determine building block total revenue.

We recover the building block revenue through our prices. We are required to set our prices such that the total revenue we recover through prices is the same as the building block total revenue.

The building block total revenue is set out in Table 13.2.

Table 13.2: Building block total revenue 2021-25 ($mil Dec 2020)

	2021	2022	2023	2024	2025
Return on capital	103.4	100.4	97.5	94.1	90.9
Return of capital (depreciation)	138.8	129.8	133.5	135.7	138.9
Correction for over-depreciation	0.0	0.0	0.0	0.0	0.0
Estimated cost of corporate income tax	11.4	10.4	9.4	10.4	10.5
Operating costs	93.2	92.1	92.9	90.8	88.8
Building block total revenue	**346.9**	**332.7**	**333.2**	**330.9**	**329.1**
Smoothed total revenue	**337.5**	**334.9**	**331.8**	**335.3**	**334.3**

13.4 Prices

There are two components to our prices:

- a capacity (or reservation) component; and
- a commodity (or throughput) component.

The capacity (or reservation) price is set to cover the fixed costs of delivering reference services and is determined by dividing the sum of the fixed cost elements of our building block total revenue (determined as building block total revenue minus SUG) by the forecast capacity demand.

The commodity (or throughput) price is set to cover the variable costs, being SUG, of delivering reference services and is determined by dividing the variable cost components of our building block total revenue by the forecast throughput.

As a result of reductions in our SUG costs, the proportion of fixed and variable costs has shifted in comparison to AA4. As a result of this reduction, the commodity component of our tariff (which recovers our variable SUG costs) has fallen from 10% in AA4 to 6% in AA5. The balance of 94% reflecting our fixed costs is recovered via the capacity component of our reference tariffs.

In line with stakeholder feedback, we have not proposed any changes in the way our costs are allocated between the Full Haul (T1), Part Haul (P1) and Back Haul (B1) services. This is because we first convert all services into a "full haul equivalent" value (multiplying the quantity of gas in TJ by the proportion of pipeline used by the service) and then sum all services to determine the tariff. This has the practical effect that the P1 and B1 services are the same as the T1 on a per-km basis.

Not only does this approach align with stakeholder feedback, but it also reflects the costs of providing each service; apart from some overhead costs, a shipper transporting gas halfway down the pipeline uses roughly half the pipeline infrastructure as one transporting gas the full length of the pipeline, and is charged accordingly.

Our proposed prices for AA5 are shown in Table 13.3. These prices

Table 13.3: Final plan proposed tariffs ($ Dec 2020)

	T1 service ($/GJ)	P1 and B1 services ($/GJ/km)
Capacity reservation charge	1.3349	0.000954
Commodity charge	0.0914	0.000065
Total tariff	**1.4262**	

will be increased each year by CPI less the X factors, which are 5.33% in 2021 and 0% for the remainder of AA5. Prices will also be adjusted over AA5 based upon changes in the debt risk premium.

13.5 Financeability of a pricing decision

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

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

- *funds from Operations (FFO) to debt* – which is defined as FFO divided by debt (and which measures the availability of cash flow to repay the balance of outstanding debt); and
- *FFO to interest* – which is defined as FFO divided by interest (and which measures the availability of cash flow to pay interest).

Table 13.4: Final plan key credit ratios

	2021	2022	2023	2024	2025
FFO to debt	6.42%	6.64%	7.06%	7.98%	8.42%
FFO to interest cover	2.1	2.1	2.2	2.5	2.5

FFO is calculated as total revenue less interest, opex and tax. Our view is that the ratings agencies require a sustained FFO to debt ratio of at least 9% and a FFO to interest ratio above 2.5. We also consider that the key focus of the credit rating agencies is on the FFO to debt ratio given the prevailing very low interest rate environment (making interest coverage a far easier metric to achieve).

We have assessed the key credit ratios delivered by our Final Plan (see Table 13.4). This shows that an average FFO to debt of 7.31% and FFO-to-interest of 2.3 over the next AA period, which is below required metrics for a BBB+ rated business. Note that these metrics refer to the efficient entity in the ERA model.

Note also that the outcomes in Table 13.4 include our proposed changes to the depreciation schedule. An increase in depreciation leads to an increase in cashflows. Without our proposed depreciation profile, the financeability check would be considerably worse. This would mean that the regulatory outcome is not consistent with the key assumptions used to determine the cost of debt. Even relatively small changes would mean the debt would obtain a lower credit rating than the BBB+ the ERA assumes.

As a final check we note that our average FFO to debt ratio of 7.3% is considerably less than the 8.0% recently approved by the ERA for GGP. This means that the speed with which our money is returned to our investors will continue to be substantially slower than for the GGP, despite the adjustments we have made to depreciation. This further supports our view over the reasonableness of our proposal against other regulatory comparators.

13.7 Summary

Our Plan delivers building block total revenue of $1,673 million over AA5, a reduction of $241 million (or 13%) compared to AA4.

Our proposed 1 January 2021 reference price of $1.43 (in dollars of December 2020) is a 4% increase on current reference prices.

The capacity and commodity ratio in AA5 is 94:6, compared to 90:10 in AA4, reflecting significant reductions in our forecast SUG costs driven by lower gas prices.

Our Part and Back Haul prices will continue to reflect a distance factor of the Full Haul price.

We consider that it is good regulatory practice to assess our plan (and subsequent ERA decisions) to ensure that it delivers sufficient cash flows to maintain the BBB+/Baa1 credit rating assumed by the ERA in setting the return on debt. We have done this and consider that our plan is below required metrics, which needs to be monitored through to the ERA Final Decision in light of updated information on our rate of return.

14 Pipeline Access

We have undertaken a thorough review of the terms and conditions for our reference services to correct, update and align our contracts.

IN THIS CHAPTER

We have undertaken a wholesale review of our reference service terms and conditions

Our proposed changes correct, and update our reference service contracts

Our reference service terms and conditions set the contractual arrangements between DBP and reference service customers and provide a framework for negotiated services.

We provide three reference services - full haul, part haul and back haul services – for which reference service terms and conditions are available.

We also continue to offer other pipeline services, with specific terms and conditions. For many of these services, our reference service terms and conditions form an appropriate framework for negotiated terms and conditions. We invite any current and prospective shipper to discuss their specific requirements with our commercial team, as currently occurs.

14.1 Regulatory framework

We are required to specify the terms and conditions on which each reference service will be provided in our Final Plan. Our proposed reference service terms and conditions are set out in the Proposed Revisions to the Access Arrangement and its Attachments as required by the NGR.[41]

14.2 Customer and stakeholder engagement

We commenced engagement with customers and other stakeholders on our proposed changes to the reference service terms and conditions as part of our stakeholder engagement program. Specifically, our proposed changes to the terms and conditions formed a focus for the Shipper Roundtables after the release of our Draft Plan.

On 15 November we provided Shipper Roundtable members with a draft of our proposed changes to the terms and conditions (in mark-up) and a summary table of the proposed changes. This draft was provided recognising the limited opportunity for comment before submission of our Final Plan to the ERA by 2 January.

14.3 Terms and conditions review

14.3.1 Approach

Following the change of ownership for DBP in 2017, we have taken the opportunity to undertake a wholesale review of our reference service terms and conditions. Our review has focused on:

- correcting typographical errors and anomalies;
- correcting references to matters that are no longer relevant (e.g. due to the passage of time and changes to legislation and standards);
- changes arising due to changes in the ownership structure of DBP since the last Access Arrangement; and
- aligning the Reference Contracts to the Negotiated Contracts to enhance our ability to administer

[41] NGR 48(1)(d)(ii)

all of our contracts in a consistent manner.

Following this review, we have proposed a number of drafting changes to the terms and conditions for each reference service for AA5. An overview of these is provided in Section 14.3.2.

Clean versions of proposed T1, P1 and B1 Service terms and conditions are provided as Attachments 2, 3 and 4 of the Access Arrangement Document.

A detailed overview and justification of each change is provided in Attachment 14.1.

Marked up versions of proposed T1, P1 and B1 Service terms and conditions showing the changes in comparison with the current AA terms and conditions (provided in word as the ERA approved corrigenda Word versions to DBP by the ERA on 20 July 2016) are contained in:

- Attachment 14.2 - T1 Service terms and conditions
- Attachment 14.3 - P1 Service terms and conditions
- Attachment 14.4 - B1 Service terms and conditions.

14.3.2 Key changes

Each change and the basis for it are set out in detail in Attachment 14.1. Key changes include:

- new definitions of Aggregated T1, P1 and B1 Services have been included to reflect the use of those terms in the Curtailment Plan, Reference Contracts, Negotiated Contracts and Standard Shipper Contracts;
- amendments to align relevant curtailment provisions;
- amendments to the fall-back rule applicable where a Shipper does not tell the Operator in which order it is to apply gas received. The amendments align allocation of gas at inlet points across all contracts with the same shipper;
- amendments to the maintenance charge for inlet and outlet stations to better reflect the intent that these costs are recovered fairly across shippers;
- amendments to better align the imbalance and peaking remedies across the Negotiated Contracts, the Standard Shipper Contracts and the Reference Contracts; and
- amendments to the relocation clause to make clear a relocation is not automatically available as of right.
- The above is not an exhaustive list and the detailed explanations in Attachment 14.1 should be considered.

14.4 Access Arrangement Document

Alongside our Final Plan, we are proposing a number of revisions to the DBP Access Arrangement Document. These revisions include:

- updating the description of the pipeline;
- updating the reference and non-reference services provided and aligning with proposed amendments to the terms and conditions;
- updating provisions relating to access requests to reflect updates to the NGR (in particular, rule 112);
- in respect of the depreciation for establishing the Opening Capital Base for the next AA period, updating the groups of physical assets that form the DBNGP;
- extending the application of a number of fixed principles. This is to extend their application for a further Access Arrangement period (e.g., fixed principle 13.2);
- insertion of an operating cost efficiency incentive mechanism under NGR 98 (see Chapter 12 and Attachment 12.2);
- updating the provisions relating to annual variations of reference tariffs; and
- making consequential definitional changes and corrections.

14.5 Summary

We have undertaken a thorough review of our reference service terms and conditions, and as a result are proposing a number of changes. These changes focus on:

- correcting typographical errors and anomalies;
- correcting references to matters that are no longer relevant;
- changes arising due to changes in the ownership structure of DBP since the last Access Arrangement; and
- aligning the Reference Contracts to the Negotiated Contracts to enhance our ability to administer all of our contracts.
- We have also proposed changes to the Access Arrangement document to reflect the updated terms and conditions, changes to the NGR, and to incorporate our proposed opex incentive scheme (the E Factor scheme).

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