S§§suz w¡§2C@D

Draft Plan DBNGP AA6

January 2025

PUBLIC

Dampier Bunbury Pipeline

Five year plan for the

Dampier Bunbury Natural Gas Pipeline

Dampier Bunbury Pipeline

1 January 2026 - 31 December 2030

DRAFT PLAN

July 2024

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 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 to the long term interests of our customers and stakeholders.

CEO Foreword

Our Draft Plan for the Dampier to Bunbury Natural Gas Pipeline (DBNGP) takes place in a time of ongoing change in the energy sector and in a higher cost environment than the previous Access Arrangement period. The Draft Plan is a key part of our ongoing engagement with our Shippers and more broadly in developing our plans for the next Access Arrangement period.

This document sets out our plans for the next Access Arrangement (AA) period from 1 January 2026 to 31 December 2030. It describes how we will continue to deliver safe and reliable services to our customers during a period of ongoing change in the energy sector.

Dampier Bunbury Pipeline (DBP) owns and operates the DBNGP and is part of the Australian Gas Infrastructure Group (AGIG), one of Australia's largest energy infrastructure businesses. The DBNGP is one of the most important pieces of energy infrastructure in not only Western Australia, but Australia as a whole. It transports natural gas over 1,600 km from the state's north-west to Bunbury, south of Perth, and the surrounding regions for use in power generation, minerals processing, alumina refining and in our homes.

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

Performance during AA5

In the current AA period (AA5), from 1 January 2021 to 31 December 2025, we have performed well against our vision.

Our customers are increasingly looking to the DBNGP to provide a reliable and flexible source of energy to support the ever-growing proportion of renewable electricity supply.

In February 2024, as Western Australia and Perth sweltered through record heat, the DBNGP saw record flows of natural gas in support of dispatchable gas fired power generation. We maintained 100% reliability throughout this period, clearly demonstrating the resilience of the DBNGP and the vital role of natural gas for Western Australia's energy security.

Our strong operational performance has remained above target throughout the current AA period—with no curtailments and 100% system reliability throughout AA5 to date.

On the safety front, there have been no Tier 1 or Tier 2 process safety incidents (the most serious). The Total Recordable Injury Frequency Rate (TRIFR) is currently at 6.5 for 2024 YTD, above our target of 4. This remains a key focus area for improvement, consistent with our vision to achieve Zero Harm for our employees, contractors and visitors.

Challenging conditions have affected DBP's performance against AA5 expenditure benchmarks. In the current AA period, inflation and tight labour market conditions have had a significant impact above and beyond expectations at the time our Final Plan for AA5 was approved.

This has resulted in our capital expenditure being above the benchmarks set for the current period, notwithstanding prudent deferrals and re-scoping of projects where sensible to do so. Despite these challenges, we are pleased that our controllable operating expenditure (such as wages and salaries) has been held to levels below the benchmark set for the current AA period.

Plans for AA6

Looking forward to the next AA period (AA6), challenging economic conditions centred on ongoing inflation and contract labour availability are likely to persist.

Most notably for AA6, our early modelling shows that a significant increase in our forecast funding costs will have a material impact on prices for our services. This Draft Plan for AA6 utilises a placeholder rate of return of around 7.52% reflecting current market conditions, more than double the 3.54% applied in AA5.

Leading into AA5, rates of return were at historic lows. However, recent high inflation, precipitating increases to cash rates from the Reserve Bank of Australia (RBA), has impacted our funding costs for AA6. It is worth noting that between now and the Economic Regulation Authority's (ERA) Final Decision expected towards the end of 2025, we can expect further volatility.

Our operational expenditure forecast for the AA6 period reflects our most recent actual operational expenditure towards the end of AA5, when the labour market and other cost pressures impacted our expenditure.

In line with higher costs across the Western Australian economy, our AA6 capital expenditure forecast is higher than that delivered in AA5. The forecast incorporates recurrent programs of work along with some new projects. A significant new project under consideration, and for which the business will be seeking feedback, is the compression reduction project. The aim of this project is to reduce both our ongoing costs and the carbon footprint of the DBNGP, in turn assisting Western Australia to achieve its decarbonisation target.

Future of Gas

At the time of the last AA5 review we proposed bringing forward the recovery of our investment in the DBNGP to reflect the relative long-term uncertainty of natural gas infrastructure in a net zero carbon future. This is otherwise known as accelerated depreciation. The ERA agreed that there is long-term uncertainty around the future of the DBNGP given some assets would not be fully depreciated until 2090. As such, the economic life of the asset was brought forward to 2063, meaning the DBNGP would be fully depreciated by that date.

While there is greater recognition of the importance of natural gas in supporting renewable electricity, the longer-term uncertainty remains. We are therefore looking to build on our approach from AA5 for AA6 and assess what, if any, changes to our depreciation profile are required.

Demand and Price

At this stage our demand forecast for AA6 reflects current levels of demand being experienced by the DBNGP. However, by the time of our Final Plan, due to be submitted to the ERA by 1 January 2025, we expect to be in a better position to provide a forecast of demand over AA6. Importantly, as with AA5, we will rely on the contracted requirements of Shippers to set the demand for AA6. This worked well in AA5 with actual Full Haul capacity largely consistent with the benchmark. The approach also enables full transparency with the ERA through provision of the requisite contract schedules.

Our Draft Plan presents an indicative price for AA6 of $2.41/GJ FHE ($2024), an uplift of $0.84/GJ on the current price of $1.57/GJ. The significant increase in price is almost entirely due to the increase in our funding costs due to the increase to the rate of return. We will update our Shippers and other stakeholders regularly on our proposed price as we develop our Final Plan.

This Draft Plan for the AA6 period has been developed following a significant program of customer and stakeholder engagement. Our program has included roundtable meetings with around 25 of our Shippers.

The Draft Plan encapsulates the feedback received thus far from Shippers at the roundtable meetings and in individual discussions. I would like to thank all stakeholders for their participation to date and look forward to more engagement between now and when we present our Final Plan to the ERA.

The Draft Plan provides an important platform from which to continue further consultation, including through further Shipper Roundtable meetings. I encourage stakeholders to make a submission on this Draft Plan. Our Final Plan, to be submitted to the ERA by 1 January 2025, will carefully reflect on all feedback received.

Craig de Laine

Chief Executive Officer

Draft Plan 2026 –2030
Delivering for Western Australia

Our plan will ensure we continue to deliver a safe and reliable source of energy for our customers during the energy transition.

In a higher cost environment, we remain committed to servicing our customers efficiently and playing our pivotal role in the Western Australian economy.

Delivering for customers

100%
reliability of the DBNGP

0
loss of containment of an energy source

>8 out of 10
customer satisfaction

in line inspection activity to ensure the smooth operation of DBNGP

A good employer

>65%
employee engagement

>99%
transmission training compliance

Compressor Station accommodation upgraded for a more diverse workforce

maintaining our strong safety performance with continued focus on achieving zero harm

Sustainably cost efficient

$9 m
outperformance of benchmark for 'controllable' opex in AA5

cost challenges met with prudent revisions to project deliveries

7.52%
regulated rate of return (3.54% in AA5) driving higher prices

projects focused on decarbonisation to support cost efficiency and emission reduction of DBNGP

Full Haul reference price of $2.41 significantly impacted by rate of return more than doubling from current period to the next period

Glossary			
AA	Access Arrangement	GEA	Gas Engine Alternator
AA5	DBNGP Fifth Access Arrangement (for the period 2021-2025)	GC	Gas Chromatograph
AA6	DBNGP Sixth Access Arrangement (for the period 2026-2030)	GJ	Gigajoule/s
ABS	Australian Bureau of Statistics	LTIFR	Lost Time Injury Frequency Rate (the number of lost-time injuries per million hours worked)
AER	Australian Energy Regulator	MLV	Mainline Valve
AGIG	Australian Gas Infrastructure Group	MRP	Market Risk Premium
ALARP	As low as reasonably practicable	MS	Meter Station
AMP	Asset Management Plan	NGL	National Gas Law
capex	Capital Expenditure	NGR	National Gas Rules
CCVT	Closed Circuit Vapour Turbines	opex	Operating Expenditure
CESS	Capital Expenditure Sharing Scheme	PJ	Petajoule/s
CMS	Contract Management Solution	PMM	Project Management Methodology
CPI	Consumer Price Index	PMO	Project Management Office
CRS	Customer Reporting System	PPI	Producer Price Index
CS	Compressor Station	PRC	Project Review Committee
DBNGP	Dampier to Bunbury Natural Gas Pipeline (used in reference to the pipeline)	SCADA	Supervisory Control and Data Acquisition
DBP	Dampier to Bunbury Pipeline (used in reference to the companies which own and operate the pipeline)	SP-2	Security Profile level 2
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
ERP	Enterprise Resource Planning	TJ	Terajoule/s
FOG	Future of Gas	TRIFR	Total Recordable Injury Frequency Rate (the number of total recordable injuries per million hours worked)
FFO	Funds from Operations	WPI	Wage Price Index

1 Plan highlights

Our Draft Plan outlines the activities and investments we propose to undertake for the 2026 to 2030 period and the resulting price change for our customers.

IN THIS CHAPTER:

- **We continue to deliver strong safety, reliability and cost performance in AA5**
- **Our investments in AA5 and AA6 will ensure we maintain our strong performance in the future**

Our Draft Plan is an important part of our stakeholder engagement program and will inform the Final Plan (or AA Proposal) we are required to submit to the ERA by 1 January 2025.

The following sections highlight the development of this Draft Plan, our achievements in AA5, the key elements of our plans for AA6 and where you can find more information on the elements of our plans in this Draft Plan document.

Our overarching objective is to submit a Final Plan to the ERA that delivers for customers, is underpinned by effective stakeholder engagement and is capable of being accepted.

This Draft Plan is key to achieving this objective and is the platform by which we finalise our plans with our customers and stakeholders. This plan outlines the feedback we have received from stakeholders, the key activities and expenditure we intend to undertake, and the prices we propose to charge over the AA6 period. We will consider feedback on this plan before we finalise our AA Proposal by the end of this year.

This section summarises what we have delivered over the current AA period (AA5) and what we propose to deliver over the next AA period (AA6).

1.1 What we have delivered

We have continued to deliver on the high expectations placed on us, including by meeting key safety and reliability standards set for our business. Our key achievements in the 2021 to 2025 period so far include:

Delivering for customers

- Consistent and 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;
- Critical support provided to the SWIS by delivering gas for electricity generation during the heat wave in the summer of 2024; and
- Delivering and implementing our customer satisfaction surveys, which for the first time, provide the business with direct information to understand and improve our customer service.

A good employer

- Strong safety performance where we have averaged less than two lost time injuries per annum in our workforce for the first three years of the AA period;
- Meeting the challenge presented by COVID-19 lockdowns by maintaining employee engagement at least in the top 50% for our industry through AA5; and
- Beginning our program to renovate/refurbish the original compressor station accommodation on the DBNGP to cater for a more diverse workforce.

Sustainably cost efficient

- Our forecast to spend below our controllable operating expenditure benchmark for AA5.

1.2 What we will deliver

Our Draft Plan for AA6 builds on our strong performance over AA5. The activities and expenditure we propose to undertake in the five years include to:

Delivering for customers

- Maintain our strong performance on reliability and public safety;
- Deliver standalone communications infrastructure for the northern section of the DBNGP;
- Replace obsolete control systems; and
- Modernise the customer experience.

A good employer

- Maintain strong health and safety performance;
- Maintain high levels of employee engagement; and
- Complete the redevelopment our depot at Jandakot to provide fit-for-purpose office and training spaces, weatherproof warehousing for critical equipment and spares, and improve site ingress and egress.

Sustainably cost efficient

- Invest in our IT systems, data management and digital capabilities.

1.3 Next steps

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

The Next Steps section (2.9) provides details on how you can provide your feedback to us on this Draft Plan for the DBNGP.

2 Our business

A significant majority of the gas used in Western Australia is transported in the DBNGP, making the pipeline one of the most important pieces of infrastructure in the state and Australia.

IN THIS CHAPTER:

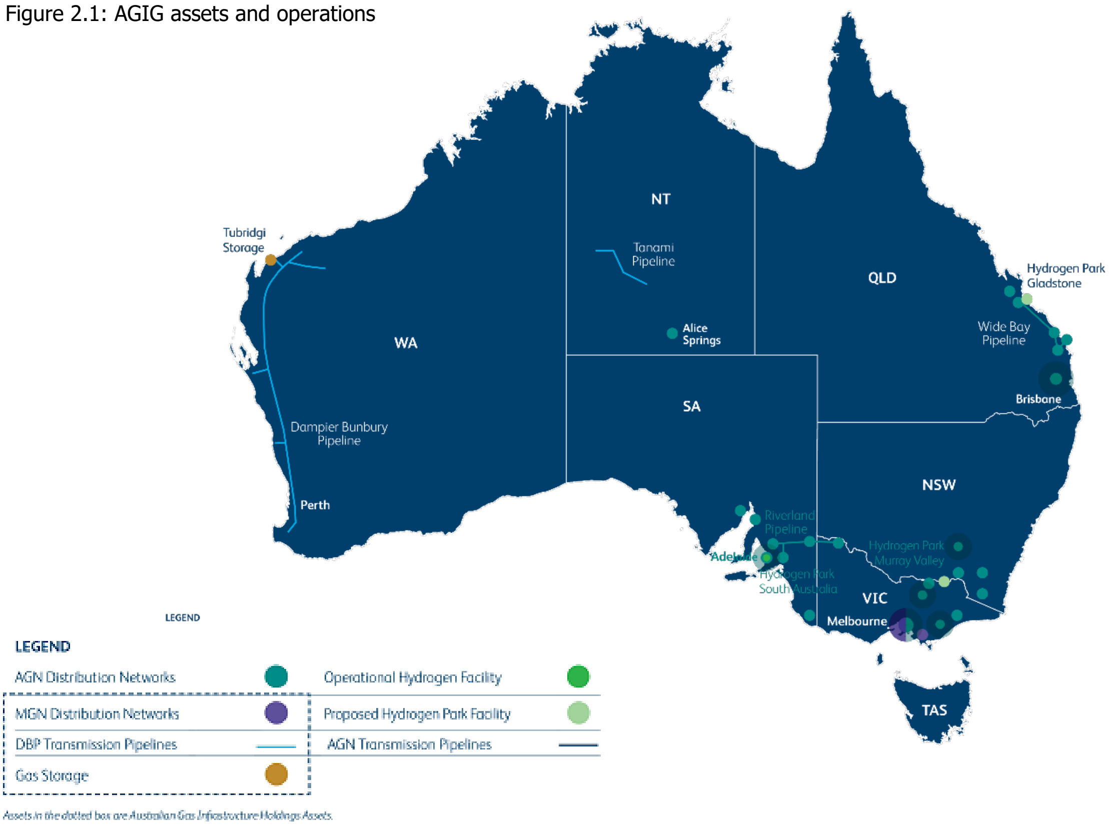
- **AGIG is one of Australia's largest gas infrastructure businesses**
- **Our vision and values drive what we do and the way we do it**
- **Your feedback is key in the development of our plans and we take a no surprises approach to stakeholder engagement**

DBP, the owner and operator of the DBNGP, is part of AGIG, one of the largest gas infrastructure businesses in Australia.

2.1 About AGIG

AGIG serves over 2 million customers across every mainland state and the Northern Territory. Our assets include over 35,000

Figure 2.1: AGIG assets and operations



km of distribution networks, over 4,300 km of transmission pipelines and 60 PJ of gas storage capacity.

In Western Australia, we own and operate critical assets that deliver and store the gas that supports the state's economy. This includes the DBNGP, Western Australia's single most important piece of energy infrastructure.

2.2 Our values

Our values of respect, trust, perform and one team drive our culture, how we behave and how we make decisions.

As owners of critical infrastructure, which provides essential services to Australians, we must ensure we act with integrity and do the right thing for current and future generations.

2.3 Zero Harm

In developing the DBNGP Draft Plan, and in all our activities, maintaining the safety of our workforce and the public is always our priority. Our proposals do everything we think necessary to meet the requirements of our safety case, asset management plans and to work towards achieving Zero harm.

Our Zero Harm principles are 'non-negotiable'; the rules we expect our staff and contractors to follow are aimed at ensuring the safety of our workforce and the public (Figure 2.2).

Figure 2.2: Zero Harm Principles

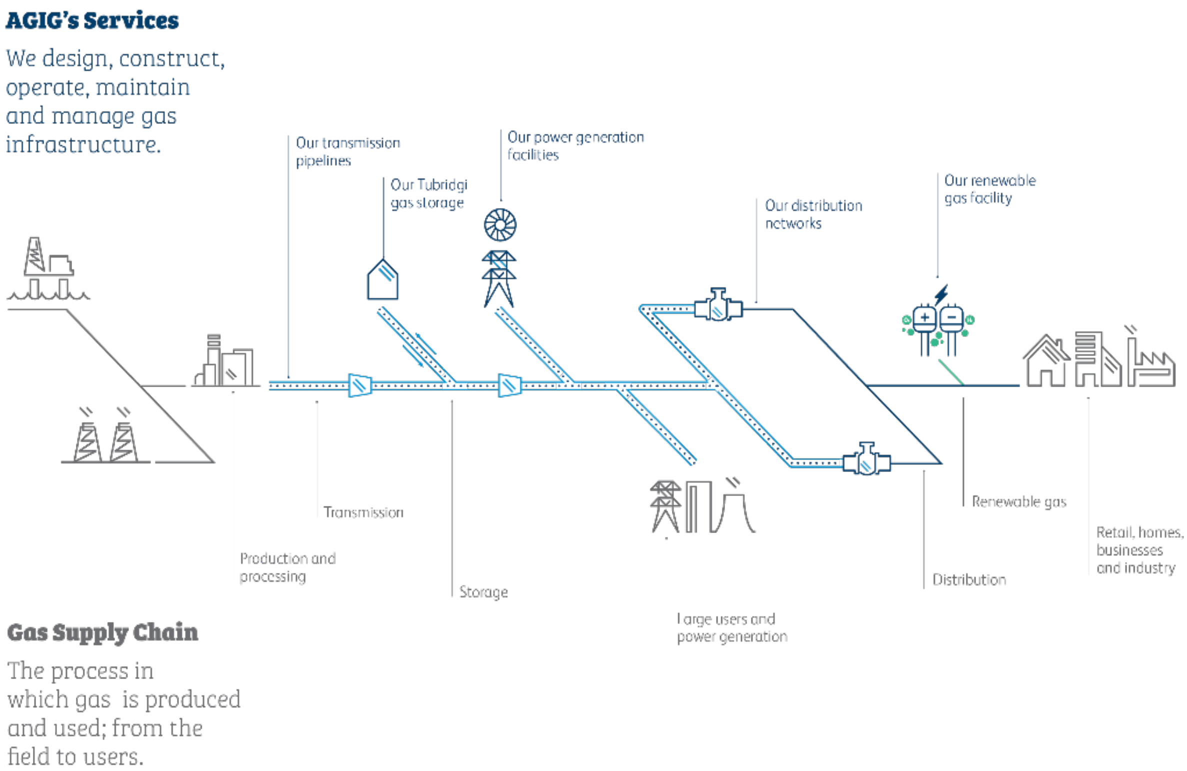
2.4 The gas supply chain

We own and operate gas infrastructure, including transmission pipelines, distribution networks and gas storage facilities across Australia. We 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 2.3 and include upstream, transmission, distribution, storage and downstream.

The DBNGP is a transmission pipeline carrying gas for our customers (Shippers) from production facilities in the northwest of Western Australia to the major load centres in the south and around Perth (Figure 2.4 on the next page).

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, which in turn delivers the gas to homes and business. Their customers are billed by the retailer of their choice. For Perth small businesses and householders, only 3% of the total gas retail bill is a result of our transmission costs.

Figure 2.3: The gas supply chain



2.5 Our role in Western Australia

Western Australia is the most energy and gas dependent economy in Australia with natural gas contributing over 50% of primary energy usage and approximately 61% of electricity generation in the state.[1]

The DBNGP is Western Australia's most critical piece of domestic energy infrastructure and is the backbone of the state's economy.

Our customers receive gas transportation and other services from us. It is our job to transport large quantities of gas safely and reliably, every day.

One of the largest capacity natural gas pipelines in Australia, the pipeline carries gas from production facilities to customers throughout the state. The pipeline stretches almost 1,600 km, linking the gas fields located in the state's north-west directly to mining, industrial, and commercial customers, and ultimately via distribution networks to residential customers in Perth. There are also emerging new supplies of gas in Western Australia from the Perth Basin, with the potential to enter the DBNGP around 350 km north of Perth. Beginning near the township of Dampier, the pipeline runs parallel to the west coast of Western Australia and ends near Bunbury.

Figure 2.4: DBNGP operation in WA

[1] Australian Energy statistics 2023. Tables C and O.

2.6 About the DBNGP

Since 1985, we have transported large quantities of gas safely and reliably along the DBNGP to provide energy for Western Australian industry, power generation, homes and businesses. Figure 2.5 shows gas received on the DBNGP by industry in 2022.

We deliver leading operational performance with 100% system reliability, 99% compressor station availability and no curtailments.

Figure 2.6 on the next page outlines the development of the DBNGP since its construction in 1984. From 2006 to 2010 the pipeline underwent significant expansion. Since 2011 a number of new sources of supply have come online and energy markets have begun a significant transition. Over AA6 we may see further changes in demand for natural gas and the way the DBNGP is used, as more wind and solar generation enters the market, and gas from the Perth Basin might become available.

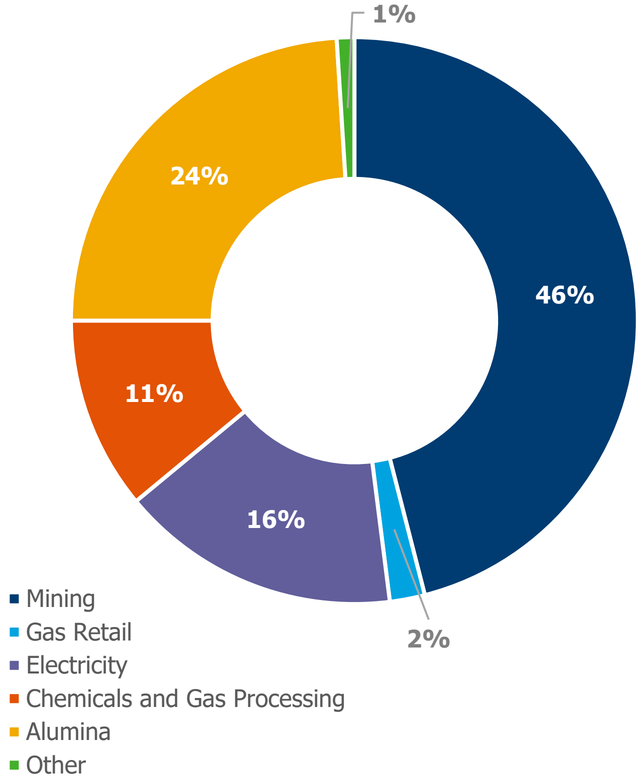
2.7 Regulatory Framework

National Gas Law (NGL) and National Gas Rules (NGR) provide the framework for the independent regulation of certain gas pipelines in Australia.

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 contains the terms and conditions under which an independent third party can gain access to the DBNGP.

Figure 2.5: Gas receivers on DBNGP by industry (2022)



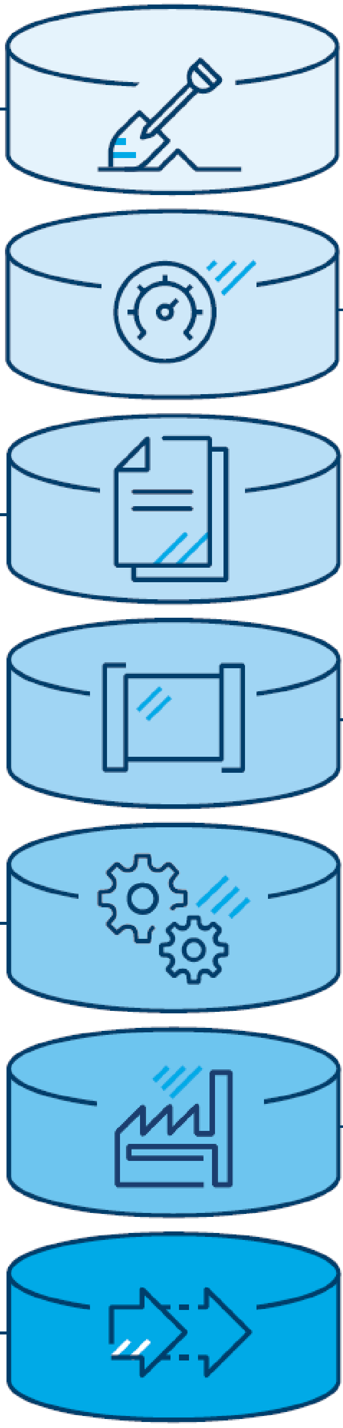
This includes:

- the price (or tariffs) paid for services; and
- the non-price terms under which access will be provided.

The NGL and NGR and the terms and conditions approved through an AA, set a framework around which pipeline operators like AGIG and users can negotiate access to meet customers' needs. We often work with our Shippers to reach agreements that provide more tailored access and services on the pipeline outside the regulated process.

Figure 2.6: History of the DBNGP

History of the DBNGP



1984
Construction

The DBNGP was constructed in 1984 by SECWA. It delivered up to 200TJ per day of natural gas from the North West Shelf to industry south of Perth.

2006
Compressors

Compressors were added to the pipeline incrementally in 1986, 1991, 1997 and 2000, expanding capacity to 625TJ per day.

2001
Regulation

Independent economic regulation of the DBNGP was introduced in 2001. The regulated reference tariff continues to set a becnhmark price for access to the DBNGP.

2006
Looping

In 2006, 2008 and 2010 the pipeline went through significant expansion to loop 85% of the pipeline, add further compressors and upgrade control systems. Total expanded capacity of 845TJ per day and capex investment of over $1.8b (dollars of the day).

2011
Changing Supply

Several new gas supplies have come online since 2011 and a large amount of supply has come into the DBNGP south of Compressor Station 1.
The changing supply dynamics, whch follow two decades of relative stability, has seen a greater utlilisation of Part Haul and Back Haul transportation services in place of Full Haul.

2021
Changing Demand

Demand for natural gas in WA is changing as energy markets and technologies, such as wind and solar, evolve. The peakiness of gas demand to power gas-fired generation has increased and gas will be used as a transitional fuel as coal generation retires over the next decade.

2026
Compression Reduction

Additional looping of the pipeline to reduce compression with a view to locking in a sustainable reduction in System Use Gas (SUG) consumption and decommissioning one or more compressor stations.

2.8 Our review objectives

This Draft Plan sets out our plans for the DBNGP for the five-year period commencing on 1 January 2026. Our Draft Plan is an important part of our stakeholder engagement program. It will inform our AA Proposal, which we are required to submit to the ERA by 1 January 2025.

Our objective 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.**

The Draft Plan incorporates feedback received to date from our customers and stakeholders and outlines our proposed approach to the Final Plan. It outlines our preliminary views on the activities and expenditure we propose to undertake during AA6 from 2026 to 2030. We also provide an indication of the likely change in prices that we will charge our customers (Shippers).

After the opportunity to comment on the Draft Plan, our customers and stakeholders will also have the opportunity to comment on the AA Proposal in 2025 through a formal process conducted by the ERA (Figure 2.7).

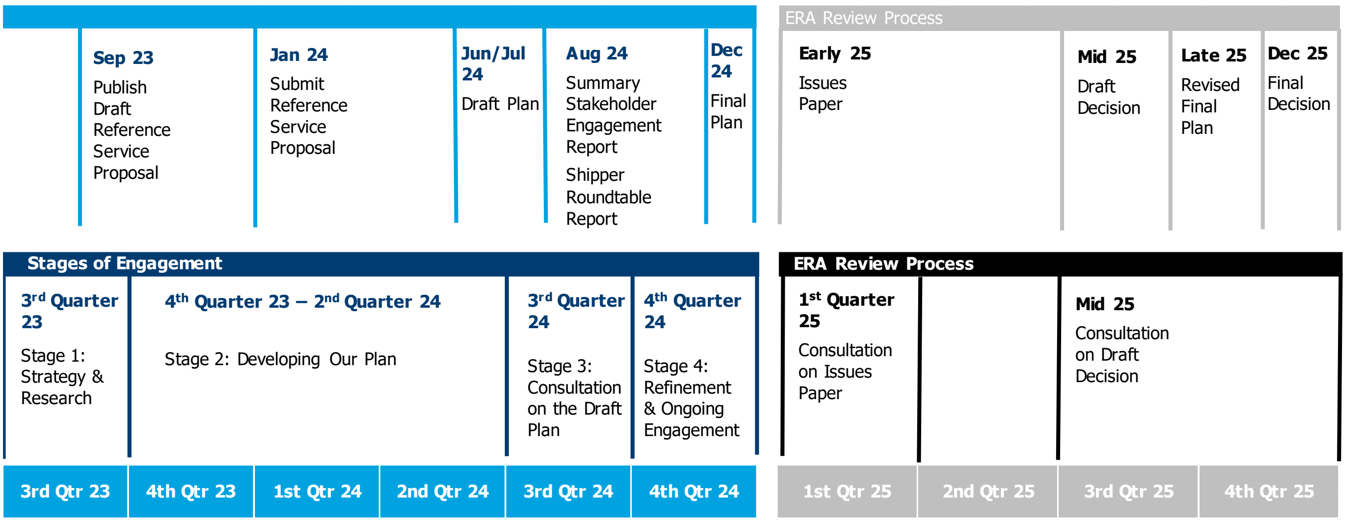
2.9 Next steps

We encourage stakeholders to provide feedback on this Draft Plan. Feedback is welcome on any and all topics relating to our tariffs and the services that we intend to provide over AA6. Your feedback is important for our objective of submitting an AA Proposal that delivers for customers and is capable of being accepted.

To guide you, we have highlighted key questions/issues that we are seeking your feedback on at the end of each section.

Please provide your feedback by 9 September 2024 via our online engagement portal, Gas Matters.

Figure 2.7: Our AA6 timeline and stages of engagement



3 Our track record

During AA5 we have maintained the reliability of the DBNGP, and the safety of our assets and our workforce, while facing challenging new operational conditions.

IN THIS CHAPTER:

- **Safety – strong public and workforce safety performance, with a continued focus on our principle of Zero Harm**
- **Reliability – 98% service availability, 100% system reliability and no curtailments**
- **Efficiency – below benchmark for our controllable opex which is not dependent on throughout and we have undertaken additional capex investment to ensure the integrity of our assets**

In AA5 we have continued to work towards our vision, despite changing and challenging operating conditions for the DBNGP.

The following sections show how we are achieving our vision to:

- deliver for customers;
- be a good employer; and
- be sustainably cost efficient.

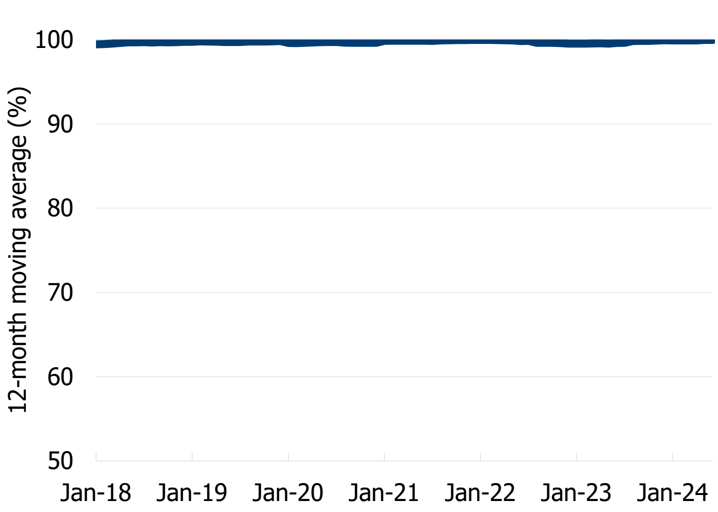
3.1 Delivering for customers

In the AA5 period we continue to deliver for our customers by maintaining the strong safety, reliability and service performance our customers value.

We have:

- delivered zero Tier 1 and Tier 2 safety incidents (incidents of primary loss of containment of an energy source);
- maintained 100% system reliability;
- maintained compressor station reliability at close to 100% (Figure 3.1); and
- invested in a total of $210 million in capex projects including:

Figure 3.1: Compressor Station Reliability



- Stations, Meter Stations and Operating Technology;
- the Northern Communications System; and
- the Transmission Billing System.

3.2 A good employer

In the AA5 period we are continuing to be a good employer by:

- maintaining our strong safety performance with an average total recordable injury frequency rate (TRIFR) of 6.1 between 2021 and 2023 per annum and an average of 1.6 lost time injuries (LTI) per annum over the same period (Figure 3.2). We are working towards a target of zero, in line with our zero harm safety principles;
- achieving e/mployee engagement results which fall in the top half amongst our comparison group of organisations; and
- investing $37.5 million in capex projects including replacing our vehicle fleet and upgrading our IT capabilities, including our OneERP system.

3.3 Sustainably cost efficient

During AA5, high inflation and tight labour market conditions have increasingly affected our performance beyond expectations at the time our Final Plan was approved.

Due to these pressures, we currently forecast an overspend of the AA5 capex benchmark by $26.6 million (14.5%) (Figure 3.3).

Figure 3.2: DBP Total Recordable Injury Frequency Rate (TRIFR) and Lost Time Injury Frequency Rate (LTIFR)

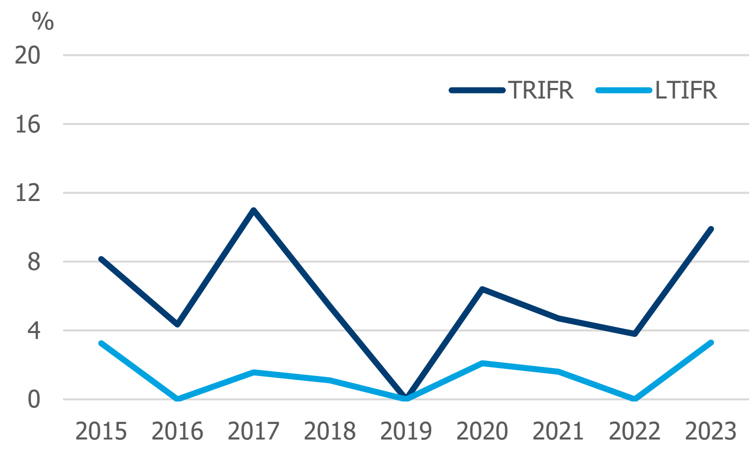
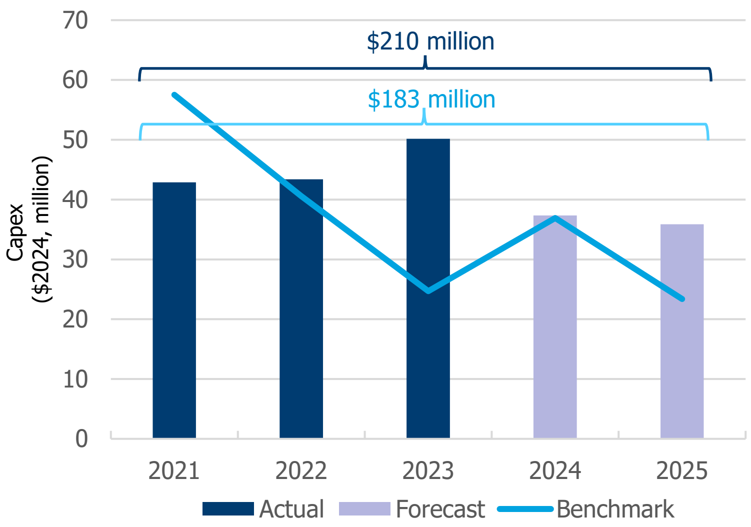


Figure 3.3: Total capex in AA5



Despite these pressures, we are on track to keep our controllable opex within benchmark.

During AA5, DBP is forecast to incur $362 million in controllable opex (excluding SUG, GEA/turbine overhauls and inspections and other asset management items), which is significantly below our allowance of $372 million for this expenditure.

Excluding SUG only, our opex is still forecast to outperform the benchmark by $2.3 million (Figure 3.4). SUG is forecast to exceed the benchmark (by $27 million) due to higher throughput in AA5 than forecast (Figure 3.5).

Figure 3.4: Total opex in AA5

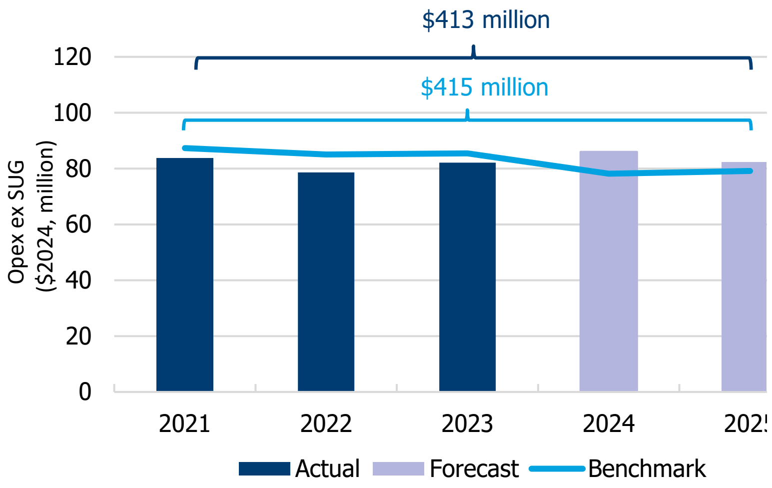
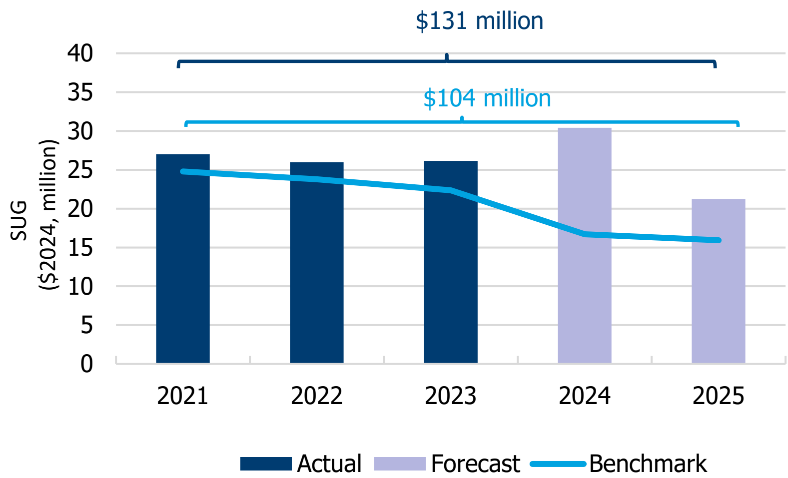


Figure 3.5: System use gas in AA5



4 What we will deliver

We will continue to deliver reliable energy for Western Australian industry, power generation and homes, as the DBNGP plays an important role in the energy transition.

IN THIS CHAPTER:

- **In AA6, we propose to maintain the strong performance achieved to date in AA5 in terms of delivering for our customers, being a good employer and being sustainably cost efficient**
- **We forecast a full haul reference price of $2.41 per GJ (before inflation), with the price increase primarily driven by financing costs**

Our Draft Plan puts in place the investments necessary to meet the changing energy needs of Western Australia.

Our Draft Plan is an important step in developing our proposal for AA6 which will:

- deliver for current and future customers;
- be underpinned by effective stakeholder engagement; and
- be capable of being accepted by our customers and stakeholders.

The following sections summarise what we will deliver in AA6.

4.1 Overview

Our Draft Plan for AA6 proposes to maintain the strong performance achieved to date in AA5, despite continued challenging operating and economic conditions including a significant uplift in our funding costs.

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

In particular, this Draft Plan supports the pillars of our vision to:

- deliver for customers;
- be a good employer; and
- be sustainably cost efficient.

An overview of our plans against the elements of our vision is included in Figure 4.1.

4.2 Delivering for customers

Delivering for customers means maintaining our exceptional record of public safety, the reliability of our services and customer service.

Our Draft Plan delivers for our customers by:

- delivering a full haul reference price of $2.41 per GJ (before inflation), which is an increase of $0.89 per GJ relative to AA5, primarily driven by financing costs;
- maintaining our strong safety performance with no loss 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;
- investing $413 million in capex projects including to undertake:
  - preventative works and repairs to protect compressor stations from corrosion and safety hazards;

- the installation of new gas chromatographs in response to changing gas flow dynamics;
- the purchase of spare meters to allow the recalibration of meters to ensure customers are billed accurately; and
- field works, asset maintenance and customer service activities.

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 AA5 we have demonstrated strong safety performance, and our Draft Plan provides the resources to continue this performance.

Through our Draft Plan we will be a good employer by:

- continuing ongoing health and safety initiatives such as undertaking audits, reporting and investigating incidents, and providing employee training; and
- investing $17 million in renovations to remote accommodation to ensure facilities are appropriate to accommodate our employees as our field workforce becomes more diverse.

4.4 Sustainably cost efficient

To be sustainably cost efficient, our Draft Plan focuses on meeting industry benchmarks and improving productivity, delivering profitable growth, and being environmentally and socially responsible.

Figure 4.2 summarises the regulatory building blocks in AA6. Our Draft Plan reference price reflects a significant uplift in our funding costs that, based on current expectations, leads to a price of $2.41 per GJ.

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

Our Draft Plan is sustainably cost efficient as it:

- is underpinned by effective stakeholder engagement;
- proposes an opex reduction of $37 million (8%) compared to our actual opex in AA5, while maintaining the reliability of the pipeline;
- delivers a capex program which is prudent, efficient, in line with good industry practice and appropriately

Figure 4.1: Our performance targets in AA6

balances our costs and risks over time;

- invests $413 million in capex projects including increased investment in cyber security, data management, digital capabilities and modernising our IT systems;
- further develops our approach to future of gas, with a focus on customer outcomes and price stability through time as substitutes for natural gas, decarbonisation policy settings and market conditions continue to evolve;
- calculates financing costs consistent with the ERA's Final Rate of Return Guidelines;
- is based on a robust analysis of the forecast demand for our reference services;
- strengthens our incentives to incur efficient opex by continuing the efficiency benefit sharing scheme (EBSS) introduced in AA5;
- proposes total revenue in AA6 that is $701 million (39%) higher than total revenue due to the low rate of return environment in AA5; and
- proposes to recover revenues from our full, part and back haul reference services consistent with the current approach.

4.5 Summary

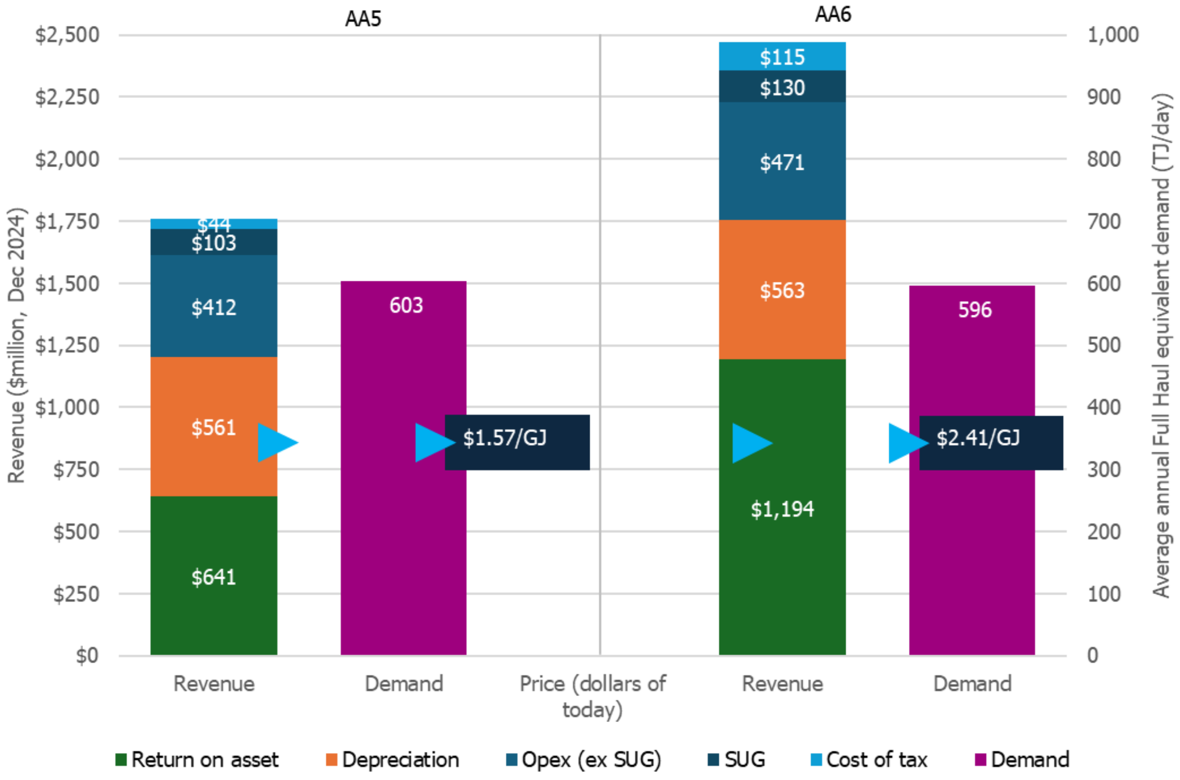
Our Draft Plan ensures we will maintain the exceptional reliability and safety of the DBNGP; we will have a safe, healthy, engaged and skilled workforce; and we will deliver value for our customers in challenging market conditions.

To aid the engagement process, we would welcome your response to the following question:

Question for consideration

1. **Do you have any feedback on our overall plans and performance targets for AA6?**

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



5 Customer and stakeholder engagement

We have actively engaged with our stakeholders to inform and shape the development of this Draft Plan.

IN THIS CHAPTER:

- **We engaged with our stakeholders to understand how they wanted to be involved in the development of our plans for the DBNGP**
- **We held a series of one-on-one and Shipper Roundtable meetings to help develop our plans, and we will continue to engage with stakeholders to refine them**

In June 2023 we began our four-stage engagement program to help us shape this Draft Plan.

We held a series of Shipper Roundtables and one-on-one meetings to receive feedback from our stakeholders on the key elements of our plans.

Effective stakeholder engagement is key to developing a plan that delivers for current and future customers and is capable of acceptance. This section explains our approach to stakeholder engagement and outlines how the program has influenced our Draft Plan for AA6.

Our Draft Plan plays a key role in the development of our Final Plan to be submitted to the Economic Regulation Authority (ERA) by 1 January 2025.

5.1 Overview

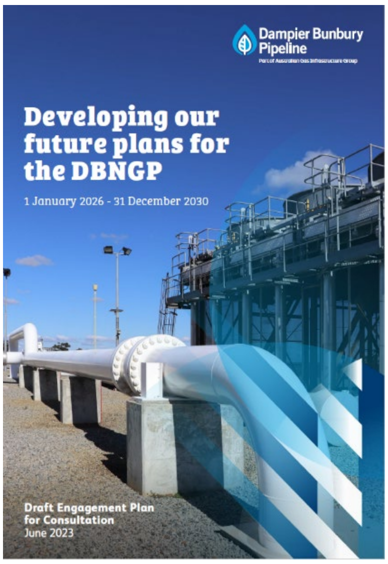
We are committed to best practice stakeholder engagement and have embedded stakeholder engagement in our planning process.

Using a four-staged approach to engagement enables us to be open and transparent – and actively encourage customers and stakeholders to be involved in shaping our plans. Our approach is one of 'no surprises' for stakeholders.

We began in June 2023 by publishing our Draft Engagement Plan for Consultation, *Developing our Future Plans for the Dampier Bunbury Natural Gas Pipeline.* The Draft Engagement Plan outlined our proposed engagement with Shippers in the development of our plans. In this document we also asked for feedback on the most important aspects of our services, and for any issues we should be considering in our future planning for the pipeline.

Shippers continue to place high value on reliability and price, with price certainty, and fair and reasonable tariffs also being important.

Shippers told us they are interested in decarbonisation, including our future plans for the DBNGP, the potential for carbon capture storage, and innovation plans to meet their changing needs.



Other topics of interest included the future planning of the use of the DBNGP as we transition into a low carbon future as well as further consideration of the future of gas modelling used in AA5.

The 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 proposed engagement strategy including our proposed approach, stakeholder engagement commitments, identification of key stakeholders, proposed engagement activities and the timeline.

Feedback was used to inform our engagement strategy, ensuring our activities were appropriate and allowed for meaningful engagement. In August 2023 we published our Final Engagement Plan which summarised key insights from our early engagement.

In June 2023 we commenced a series of one-on-one meetings with key stakeholders, followed by the commencement of the Shipper Roundtables, with the first being held in August 2023.

The initial one-on-one meetings with key stakeholders provided an opportunity to help guide our proposed engagement approach and activities, and for stakeholders to provide feedback on the most important aspects of our services and key issues we should consider in the future planning for our pipeline.

The Shipper Roundtable was established to consider and advise on key topics and issues of interest. All Shipper Roundtable meetings were facilitated by an independent third party, KPMG. Through these Roundtables, we consulted with Shippers on topics including:

- our Reference Service Proposal;
- reliability of service;
- price and services;
- rate of return;
- capital and operating expenditure proposals;
- decarbonisation and the Safeguard Mechanism;
- the future of gas and accelerated depreciation;
- demand and the changing demand profile on the pipeline; and
- understanding of the key regulatory building blocks.

Feedback has been captured and used to shape and refine this Draft Plan. A summary of feedback and how it has informed our plan is included in this chapter.

Using this Draft Plan as a platform, we will continue to engage with Shippers in the second half of the year to help guide the finalisation of our plans. This Draft Plan is published and available on our online engagement portal, Gas Matters, and open for submissions and feedback.

5.2 Our stakeholders

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

Our key stakeholder groups are illustrated in Figure 5.1 on the next page.

These key stakeholder groups represent our direct and indirect customers, and other businesses in the gas supply chain. They remain the same as with the AA5 engagement program, and include regulators, Shippers and gas marketers and producers. Stakeholders also include government departments and agencies recognising that the DBNGP is part of broader energy policy, land management, safety and environmental protection considerations.

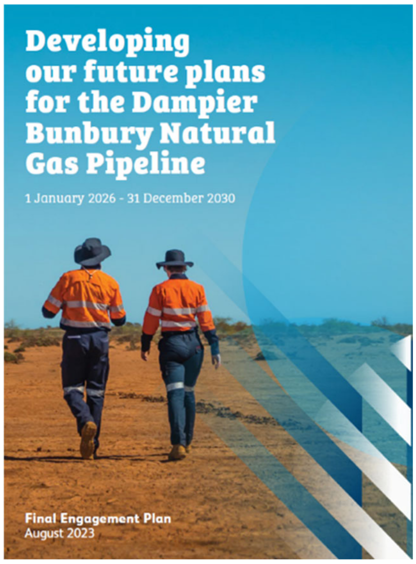


Figure 5.1: Our Stakeholders

5.3 Our approach to stakeholder engagement

We have continued with our four-stage approach to engage and involve stakeholders in our planning process, as illustrated in Figure 5.2 on the next page.

Stage 1: Strategy & Research

Stage 1 was a research stage to better understand stakeholder needs and expectations and to consult on our proposed engagement approach, ensuring we engaged meaningfully and effectively to meet stakeholder expectations. During this stage we tested our assumptions about what's important to our stakeholders and what topics they wanted to be engaged on, culminating in our Final Engagement Plan which summarised stakeholder feedback and our final engagement strategy.

Stage 2: Developing our Draft Plan

In Stage 2 we used the insights from Stage 1 to inform the drafting of our plans. Stage 2 included targeted engagement activities on our investment proposals and regulatory modelling. During this stage we ran a series of Shipper Roundtable activities, including one-on-one and roundtable meetings, consulting on key topics to guide the development of our plans, as well an online deep dive information session refamiliarising Shippers on the fundamentals of the regulatory process.

Stage 3: Consultation on our Draft Plan

In Stage 3 we will consult on this Draft Plan. We will actively engage with stakeholders through a series of one-on-one, online and roundtable meetings to ensure our

Figure 5.2: Our four-stage engagement approach

Final Plan delivers for our customers today and into the future.

Stage 4: Refinement and Ongoing Engagement

Consultation feedback from Stage 3 engagement will be used to inform our Final Plan for lodgement with the ERA by 1 January 2025. Our engagement efforts will continue after we submit our Final Plan to ensure our stakeholders are kept informed, as part of our engagement program.

5.4 Stage 1 Engagement – Strategy & Research

From June to July 2023, we undertook engagement activities to better understand our stakeholders' preferences for engagement and to identify key issues of interest.

5.4.1 Activities

In June 2023 we published and made available our Draft Stakeholder Engagement Plan for Consultation, *Developing Our Future Plans for the Dampier Bunbury Natural Gas Pipeline*, seeking feedback through to end of July 2023.

We engaged with around 25 Shippers, producers and gas trading agents, including holding twelve one-on-one dedicated Shipper meetings.

During June and July 2023, we met with a number of key stakeholders to discuss our proposed approach and explore key issues, including one-on-one consultation meetings with twelve Shippers. All meetings were documented, summarised and used to influence our final engagement strategy, including topics for engagement.

Upon completion of Stage 1 engagement, we documented all feedback from our stakeholders in our Final Engagement Plan.

Figure 5.3: Our third Shipper Roundtable Meeting

5.4.2 Capturing key insights

In Stage 1 we asked our stakeholders for feedback on:

- key issues of importance and topics of interest for engagement; and
- our proposed engagement strategy.

During stakeholder meetings we facilitated discussion around eight consultation questions.

- Are our engagement principles appropriate to develop plans that deliver for our stakeholders?
- Have we identified all relevant stakeholder groups?
- What are the most important aspects of our services?
- What issues should we consider in our future planning for the DBNGP?
- What aspects of our future plans would you like to engage on?
- How would you like to participate in our engagement process?
- Is our proposed approach open and transparent?
- Are there ways we could improve our proposed approach?

A summary of stakeholder feedback is captured in Table 5.1 on the next page, reflecting key themes identified in delivering for our stakeholders both today, and in the future.

Table 5.1: Summary of Stakeholder Feedback

Topic	Stakeholder Feedback	Our Response
Key Insights	• Stakeholders placed a strong focus on decarbonisation, including future plans for the DBNGP, hydrogen and carbon capture and storage, and the impact of renewable energy on gas flows, pipeline operations, the location of supply and/or demand centres, capacity, and the implications of policy changes. • Stakeholders continued to place a high value on the reliability and safety of the DBNGP. • Reliability and price were two important considerations for stakeholders. Price and price certainty, with fair and reasonable tariffs that meet industry and customer expectations, were also important. • Innovation plans for the DBNGP to meet the changing environment and stakeholders' needs was a key area of focus. • Some stakeholders wanted us to consider a flexible approach in the development of our future plans acknowledging the dynamic nature of the energy industry. • Further consideration of future of gas modelling, future use of infrastructure, with gas being a transition fuel and potential use of renewable electricity generation for compressor stations were also important issues for future planning for the DBNGP. • Consideration of stakeholders' future needs being modelled where possible and balanced with current costs was identified by some stakeholders. • Some stakeholders wanted the inclusion of their future needs in the overarching objective when planning for reliability, products and services, terms and conditions, and future price paths.	• We will explore these key insights with our stakeholders as we develop our Draft and Final Plans.
Our Engagement Approach and Principles	• Stakeholders appreciated the opportunity to provide feedback on our proposed engagement process and to participate in future stakeholder consultation as planning develops. • Stakeholders valued our transparent, inclusive and collaborative approach to stakeholder engagement. Stakeholders noted early and transparent consultation was important to support our 'no surprises' approach and assist with our future planning, particularly as we transition towards a low carbon future.	• We confirmed our commitment to our engagement principles, a 'no surprises' approach and our objective of submitting a plan capable of being accepted. • We confirmed our continued four-stage engagement approach. • We agreed to less Shipper Roundtable meetings than the previous AA period and instead offered ongoing one-on-one meetings and deep dive information sessions when required.
Our Stakeholders	• Stakeholders were comfortable with the stakeholder representative groups identified. • Whilst some stakeholders did not want to be directly involved in our engagement activities they were still interested in being kept informed through our engagement program.	• We will focus our engagement program and engage with stakeholders directly connected to the DBNGP (and their representatives) through both Shipper Roundtable activities and one-on-one engagement where required.

Our Engagement Activities	• Stakeholders were keen to be involved in our engagement program. • Stakeholders supported the establishment of a Shipper Roundtable, noting it provides a transparent forum allowing time to discuss and understand issues throughout the regulatory process, also noting potential limited conversation due to commercial sensitivities for individual Shippers. • Stakeholders welcomed regular contact and transparency but requested fewer Shipper Roundtables than the previous AA period, with the addition of deep dive sessions throughout the process if required. • Stakeholders preferred to maintain one-on-one meetings to engage in matters from a commercial perspective. • Stakeholders were generally supportive of the ERA being present at Shipper Roundtables in the capacity of an observer, with some adding it should assist in early awareness of key issues.	• We will engage with Shippers with less frequent Shipper Roundtables compared to the previous AA period. • We will continue to engage with individual Shippers on commercial aspects directly with one-on-one meetings. • We will provide deep dive information sessions as required. • We will provide regulatory stakeholder engagement updates throughout the process.
Our Timeline	• Stakeholders supported our timeline.	• We confirmed the timeline for developing our plans.

5.5 Stage 2 Engagement – Developing our Draft Plan

In Stage 2 we delivered engagement activities based on preferences received from stakeholders during Stage 1 of our engagement.

Stakeholders supported a blend of Shipper Roundtable meetings (to discuss regulatory issues) and one-on-one meetings (to discuss more commercially sensitive matters) as required. Some Shippers also indicated an interest to take part in online information sessions should the need arise throughout the engagement process.

5.5.1 Activities

We commenced a series of Shipper Roundtables in August 2023, where all direct customers and gas trading agents were invited to take part. In total, we held three Shipper Roundtables to May 2024.

All Shipper Roundtables were facilitated by an independent third party, KPMG, to ensure independence in the documentation of feedback. Roundtable meeting topics were presented based on the issues of importance raised during Stage 1 of our engagement, as well as key components of this Draft Plan. A summary of key topics and information presented was summarised in Table 5.2.

Shippers were offered the opportunity to provide feedback during the meetings, and KPMG offered one-on-one stakeholder feedback sessions at any time. We also encouraged Shippers to request additional information that may assist in supporting meaningful engagement.

All Roundtable meetings were documented by KPMG, with minutes circulated to attendees and posted on our online engagement portal, Gas Matters.

In December 2023 we also hosted an online information session for Shippers covering regulatory fundamentals including building block revenue, demand and price, and capital and operational expenditure.

5.5.2 Key insights in Draft Plan

A summary of feedback captured during the Shipper Roundtables is provided in Table 5.3.

In this summary we illustrate how we have responded to stakeholder feedback to inform the development of this Draft Plan across the key topics discussed at the Shipper Roundtables.

Table 5.2: Shipper Roundtable Meeting Topics

Meeting #	Key Topics	Summary of information presented
Meeting #1	• Our Engagement Approach • AA5 Performance to Date • Reference Service Proposal	• Role of the Shipper Roundtable • Our Stakeholder Engagement Approach – including principles, fit-for-purpose activities, key topics and timeline • Key Insights from Stage 1 Engagement • Reference Service Proposal – factors, background and our proposed approach
Meeting #2	• Reference Service Proposal • Rate of Return • Operating Expenditure Performance and Plans • Future of Gas / Accelerated Depreciation Update	• Reference Service Proposal status and timing, proposed and excluded services • Key price drivers and impacts • Rate of return and inflation impacts, return on asset • Operational expenditure factor forecasts, AA5 performance • Future of gas and accelerated depreciation - price stability
Meeting #3	• Demand • Capital Expenditure Proposal	• Demand approach and forecast for AA6 • Proposed Capital Expenditure including development background, stay in business and forecast comparisons between AA5 and AA6, and compression reduction project

5.6 How we will engage on our Draft Plan

This Draft Plan is open for consultation for six weeks from publication and available on the DBP website and our online engagement portal, Gas Matters.

We are inviting submissions in writing, or via a facilitated one-one-one meeting.

To support meaningful engagement, we will:

- offer one-one-one meetings with stakeholders in August 2024; and
- hold a Shipper Roundtable in August 2024 to capture feedback from the group.

We will summarise feedback received on our Draft Plan and use it to inform our Final Plan.

Our Final Plan will include all feedback we received during the consultation period and outline how this feedback was used to inform our Final Plan.

5.7 Summary

One of our key objectives is to deliver a plan which is underpinned by effective stakeholder engagement.

We have been open and transparent in our approach and sought feedback throughout the process of developing our plans. We have documented our process and demonstrated how feedback has been used across Stage 1 and Stage 2 of our engagement plan.

This Draft Plan has been shaped by our engagement activities and delivers in the long-term interests of stakeholders.

We will continue engaging with stakeholders on our proposals within this Draft Plan. Feedback will be used to inform our Final Plan, which will be lodged with the ERA by January 2025.

To aid the engagement process, we would welcome your response to the following question:

Question for consideration
1 **Do you have any feedback on our stakeholder engagement program including our remaining engagement plans for AA6?**

Table 5.3: Shipper Roundtable Feedback and our Response

Topic	Stakeholder Feedback	Our Response
Our Engagement Approach	• Stakeholders were supportive of the role of the Shipper Roundtable, our proposed engagement process, and acknowledged our 'no surprises' approach. • Shippers agreed in principle to the topics, format and proposed timing of future stakeholder engagement sessions. They were also comfortable with the regulatory process timeline for AA6 and the ERA's role in the process. • Shippers were concerned about sharing commercially sensitive information in group sessions. • In general, stakeholder groups indicated they would like to be kept informed of our progress and plans, including in the lead up to stakeholder sessions.	• We sought feedback from Shippers at each Roundtable meeting on the process and our engagement approach. • Information presented at the Roundtable meetings covered the regulatory review process only and did not include individual Shipper requirements or contractual arrangements. We offered additional one-on-one meetings with individual Shipper representatives, including with our facilitator, KPMG, if requested. • Meeting materials were made available to stakeholders prior to the Shipper Roundtables and subsequently housed on our online engagement portal, Gas Matters. • At the end of the process, we will survey Shippers on the effectiveness of our engagement process.
Future of Gas	• Clarification was sought on the economic life of the pipeline and our approach to accelerated depreciation.	• We are considering a tilted profile for economic recovery, rather than changing the economic life of the pipeline. • Our primary principle for the upcoming period concerning accelerated depreciation is to focus on customer outcomes, including demand and price stability, to lower risk in the face of decarbonisation challenges and the energy transition. Our approach is outlined in Chapter 6.
Pipeline & Reference Services	• Shippers generally supported the Draft Reference Service Proposal (RSP) including the proposed reference services, although there were issues raised by one Shipper in a submission to our draft proposal which we further considered in our Final RSP. • One Shipper asked what leads to the classification of peaking and other services as non-reference services and about the tariff implications of excluding services from reference services. • In the context of tariffs, Shippers asked if the tariffs were fixed for the entire AA6 period and how the impact of rebates would change the tariffs annually. One also asked why the Overrun service is charged at Spot rates. • Regarding the nature of the pipeline services we offer, one Shipper asked whether the pipeline system could accept the injection of alternative gases to natural gas.	• We responded directly to questions about our services in our Roundtables and we met with the Shipper that made a submission raising issues about our RSP. • We also posted information summarising available services, including our Draft RSP, on Gas Matters. The ERA informed attendees that all its decisions and reasons are published on its website, ensuring complete transparency. • As discussed in Chapter 7, our Final RSP incorporates our responses to the issues raised about our reference and non-reference services, with reference to the Reference Service Factors (RSFs) that must be considered in classifying reference services under NGR 47A. The ERA noted in a roundtable that not all RSFs need to be met necessarily for a service to be a reference service. The ERA has since approved the Full Haul, Part Haul and Back Haul services as our only three reference services for AA6, the same as in AA5. • We recover tariff revenue for the estimated cost of reference services, but some non-reference service revenue (eg, Peaker and Spot) is rebated (with an annual reduction to the reference tariff). This is mainly because the demand is unpredictable and so costs cannot be easily allocated to these services.

		Therefore, Shippers should account for this downward adjustment to the reference tariff over the AA period. • We explained that the Spot Capacity Service is available to shippers with Standard Shipper Contracts and that Overrun charges are a behaviour charge applied where throughput exceeds contracted capacity on a day. • As some issues raised around tariffs are not part of the RSP, we offered to meet with individual Shippers as needed. • Regarding alternative gases, we explained in the roundtable how other gases, such as hydrogen and biomethane, can be injected into the pipeline system, so long as they meet gas specifications. However, there are currently no plans for such injections, and any related assets and infrastructure would be separate from the DBNGP.
Our Capital and Operating Expenditure Proposals	• No significant concerns were raised about our proposed approaches to forecasting operating and capital expenditure, our initial draft forecasts or our update on our performance in AA5. Shippers requested that we provide more details on our specific plans for AA6 (in our Draft Plan). • Shippers were interested in the value of a small number of deferred capital projects, including if any interest would be earned and what it would be used for. • Shippers enquired if the Compression Reduction Project would reduce the speed of the gas in the pipeline and if there would be any emissions reduction, and whether compressors being switched off would be reflected in the business case calculations/feasibility. • Shippers requested an update on the Pluto Expansion Project. • Some Shippers were concerned about gas specifications on the pipeline and the risk to them regarding the flow and quality of gas. One commented on the need to take action themselves if the required gas specifications were not met. In addition, they asked if the ERA's authority could be utilised to shift the risk back to producers, thereby preventing the passing of gas chromatograph costs to Shippers. It was proposed that we recommend changes so the ERA could address this issue, particularly if changing flow dynamics in the pipeline were involved.	• We have provided detailed information about our operating and capital expenditure plans and priorities in Chapters 8 and 9 of this Draft Plan respectively. Our AA5 forecasts and proposed expenditure for AA6 have been revised further. • The main deferred project largely related to the Northern Communications project as the initial tender responses were higher than expected, and therefore we have sought other, cheaper delivery solutions for the project. Deferred projects are not rolled into the Regulatory Asset Base (RAB). • In the roundtable, we explained that the Compression Reduction Project was being investigated for feasibility and would not reduce the speed of gas delivery. Our aim is to reduce costs and the carbon footprint without affecting capacity. • In addition, we confirmed that switching off any compressors would be reflected in the business case calculations and that we would keep Shippers informed of the next steps. We noted how there should be an emissions reduction benefit through the reduced use of compressors. We further advised how we are already undertaking projects to reduce emissions such as using solar power to operate some main line valves and other project investigations such as reducing the venting of methane. • We provided an update on how the Pluto Expansion Project is successfully advancing in line with the established schedule. The ongoing work involves upgrading the existing inlet from Pluto's top pipeline, and we are overseeing the expansion on behalf of a third party. • Regarding the issue of gas specification and who is responsible, we acknowledged the challenges in providing timely warnings due to the proximity of some producers and Shippers and the lack of timely information from producers about non-compliant gas. We emphasised that the framework

		governing gas specifications was a national framework beyond our control and that our contractual relationship was with Shippers and not producers. Additionally, we highlighted the constraints posed by legacy regulations which previously, for example, allowed over 10 hours to act but now only provides a few minutes. To address these issues, we are considering the digitisation of field staff tools to allow real-time data entry and enable better data analysis. • In the roundtable, we advised our intention to engage with Shippers directly about the issues raised about the flow and quality of gas with a view to considering potential actions. In Chapter 15, we have outlined our review of the relevant gas specification clauses (6 and 7) in the Reference Service Contracts and requested further feedback.
Rate of Return	• Stakeholders acknowledged our intentions to adopt the ERA's Rate of Return Guidelines in formulating our plans, consistent with the approach taken for our other assets. • One Shipper asked what the actual financial performance compared to the projected performance for AA5 was due to the significant expected increase in the WACC, and how has this impacted the formulation of AA6 pricing. • Another Shipper requested we provide an overview of the WACC calculations, and another about what our current gearing level.	• We responded that the Rate of Return Instrument (RoRI) served as a binding instrument that determined the methodology for estimating our WACC, and therefore our rate of return in AA6, and is published on the ERA website. • We also explained how the annual adjustment of the debt-risk premium is determined by the ERA. • The WACC (and input parameters) to be used for the AA6 Final Decision would be determined later in the process and while market fluctuations can be unpredictable, we will maintain transparency by clearly displaying the components of the calculation and soliciting early feedback. • In Chapter 11, we have presented our rate of return and financing calculations for AA6 at this stage in the process.
Demand	• Shippers asked if there were plans to increase the capacity of our pipeline. • One also asked if there had been an increase in demand resulting from development in AA5. • Another asked if the strain on the asset held any inherent value when considering overall demand. • Shippers were generally interested in how the focus of decarbonisation impacted our future needs and beyond.	• We responded in the Roundtable that our demand approach for AA6 will be the same as for AA5 concerning the capacity forecast with a high level of uncertainty due to decarbonisation. We confirmed a marginal increase following the development of AA5 but there wasn't a material difference. • We acknowledged that an investigation into expanding the pipeline's capacity is underway (Compression Reduction Project). However, no conclusion has been reached regarding the viability of the business case. Further details on our capital expenditure program will be discussed in a forthcoming Roundtable. • We acknowledged the current strain on the asset and its potential value concerning overall demand. The price as shown reflected contracted capacity in March 2024. • We mentioned how various factors affect gas movement, and sometimes it is over very small distances. • Separate to the Roundtables, we have engaged directly with Shippers to assist with demand forecasts to ensure a reasonable degree of certainty. • Our demand assumptions and modelling for the AA6 is outlined in Chapter 13 of this Draft Plan, and we shall continue to engage on them.

		Therefore, Shippers should account for this downward adjustment to the reference tariff over the AA period. • We explained that the Spot Capacity Service is available to shippers with Standard Shipper Contracts and that Overrun charges are a behaviour charge applied where throughput exceeds contracted capacity on a day. • As some issues raised around tariffs are not part of the RSP, we offered to meet with individual Shippers as needed. • Regarding alternative gases, we explained in the roundtable how other gases, such as hydrogen and biomethane, can be injected into the pipeline system, so long as they meet gas specifications. However, there are currently no plans for such injections, and any related assets and infrastructure would be separate from the DBNGP.
Our Capital and Operating Expenditure Proposals	• No significant concerns were raised about our proposed approaches to forecasting operating and capital expenditure, our initial draft forecasts or our update on our performance in AA5. Shippers requested that we provide more details on our specific plans for AA6 (in our Draft Plan). • Shippers were interested in the value of a small number of deferred capital projects, including if any interest would be earned and what it would be used for. • Shippers enquired if the Compression Reduction Project would reduce the speed of the gas in the pipeline and if there would be any emissions reduction, and whether compressors being switched off would be reflected in the business case calculations/feasibility. • Shippers requested an update on the Pluto Expansion Project. • Some Shippers were concerned about gas specifications on the pipeline and the risk to them regarding the flow and quality of gas. One commented on the need to take action themselves if the required gas specifications were not met. In addition, they asked if the ERA's authority could be utilised to shift the risk back to producers, thereby preventing the passing of gas chromatograph costs to Shippers. It was proposed that we recommend changes so the ERA could address this issue, particularly if changing flow dynamics in the pipeline were involved.	• We have provided detailed information about our operating and capital expenditure plans and priorities in Chapters 8 and 9 of this Draft Plan respectively. Our AA5 forecasts and proposed expenditure for AA6 have been revised further. • The main deferred project largely related to the Northern Communications project as the initial tender responses were higher than expected, and therefore we have sought other, cheaper delivery solutions for the project. Deferred projects are not rolled into the Regulatory Asset Base (RAB). • In the roundtable, we explained that the Compression Reduction Project was being investigated for feasibility and would not reduce the speed of gas delivery. Our aim is to reduce costs and the carbon footprint without affecting capacity. • In addition, we confirmed that switching off any compressors would be reflected in the business case calculations and that we would keep Shippers informed of the next steps. We noted how there should be an emissions reduction benefit through the reduced use of compressors. We further advised how we are already undertaking projects to reduce emissions such as using solar power to operate some main line valves and other project investigations such as reducing the venting of methane. • We provided an update on how the Pluto Expansion Project is successfully advancing in line with the established schedule. The ongoing work involves upgrading the existing inlet from Pluto's top pipeline, and we are overseeing the expansion on behalf of a third party. • Regarding the issue of gas specification and who is responsible, we acknowledged the challenges in providing timely warnings due to the proximity of some producers and Shippers and the lack of timely information from producers about non-compliant gas. We emphasised that the framework

6 Future of gas

The future of gas transmission infrastructure in a decarbonised energy environment is uncertain and our plans for the DBNGP must be adaptable to the needs of Shippers as they decarbonise in different ways.

IN THIS CHAPTER:

- **We outline how we analyse long-run future demand**
- **We show how we are considering adjusting depreciation based on expectations of future demand to keep prices relatively stable through to 2050**

Decarbonisation by our Shippers and of the DBNGP itself will change long-term demand for pipeline services. Our aim, in the face of this uncertainty, is to avoid price shocks for Shippers into the long term.

Accelerated depreciation is the bringing forward of the return of the investment in an asset. It has become an accepted means, both by industry and regulators, to deal with the long-term uncertainty of gas infrastructure assets. This includes the depreciation being applied for the DBNGP in AA5.

For AA6 we are looking to build on the approach taken in AA5. This chapter explains our approach to depreciation, the risks we are seeking to mitigate through accelerated depreciation and our modelling approach to determine the appropriate amount of accelerated depreciation.

6.1 Regulatory framework

Regulatory depreciation is governed by Section 89 of the National Gas Rules, which lays out how invested capital is to be recovered over the economic life of assets, and how changes in economic lives are to be reflected in changes to depreciation.

Prior to AA5, economic lives had not changed in roughly 20 years, but we recognised that changes coming to Australia's energy market were going to mean that consideration of changes to economic lives would become necessary. We therefore proposed changes to depreciation (see below).

A need to reflect energy market developments in depreciation has been recognised by the ERA in its AA5 decision and the Australian Energy Regulator (AER) in its Regulating Gas Pipelines Under Uncertainty paper. It has also been recognised in regulatory decisions, with each decision on gas networks around Australia since our AA5 decision reflecting some changes to depreciation schedules.

6.2 Overview

Our modelling to determine the appropriate amount of accelerated depreciation is ongoing and will be finalised by the time of our Final Plan submission to the ERA by 1 January 2025. For this Draft Plan, we have therefore applied a placeholder amount of $113 million of accelerated depreciation. This amount has been applied as it delivers (in real terms) a total regulatory depreciation for AA6 consistent with that in AA5 of $568 million. See Chapter 10 Capital Base for a further description of the total regulatory depreciation.

6.3 Stakeholder engagement

At our second Shipper Roundtable meeting held on 7 March, we discussed our proposed approach to accelerated deprecation for AA6.

Shippers sought clarification on the economic life of the pipeline and our approach to accelerated depreciation for AA6. We outlined our approach to accelerated depreciation and the modelling that we are currently undertaking.

We advised Shippers our modelling and analysis was ongoing but would not be completed in time for the Draft Plan. We advised Shippers we would continue to engage with them in order to finalise the modelling in preparation for the Final Plan due to the ERA later this year.

6.4 Risks we address with Accelerated Deprecation

To understand the risks that accelerated depreciation seeks to address, it is important to understand how our tariffs work. At present, tariffs have a 94% capacity charge and a 6% commodity charge. The capacity charge is for the right to use the pipeline, and is paid whether the pipeline is used on a given day, or for a given amount, or not. The commodity charge is paid only on gas actually transported. The commodity charge is based on actual usage - the quantity of gas transported through the pipeline.

In this context, our biggest risk occurs when a Shipper replaces all of its gas with another source of energy, reducing revenue to zero as soon as this occurs. This could happen, for example, if a given Shipper no longer requires gas or it replaces all its gas load with substitute energy sources.

A second risk occurs when a Shipper still needs gas, but changes the way gas is used because substitutes are used for some energy demand. The obvious example is renewable power generation; on many days, a Shipper might be getting most or all of its energy from renewable sources. However, on the days when these are unavailable, that entire energy supply needs to come from gas. If those days are not easily predicted, the Shipper may need to reserve capacity every single day.

The second risk might not be immediately apparent to us, because Shippers still reserve the same capacity as they always have. However, it is a risk that builds in the background because the Shipper is paying for gas to be available when it is needed and paying for whatever energy source it is actually using; the right to gas transport can become an increasingly expensive form of insurance if substitutes steadily increase their share of the energy load. At some point in time, a substitute may become economic for the final firming power requirement gas has been serving and revenue goes to zero as the first risk noted above is crystalised.

Our accelerated depreciation approach aims to address both of these risks. This chapter summarises that approach.

6.5 Context for long-term demand

There are several drivers of the future demand for our gas transportation services as the future develops. As with any business, price is one of them. In particular, the price of gas relative to its potential substitutes, like electricity from the grid, provides one example. However, price is not the only driver and it does not operate in a simple manner.

Take for example, an electricity generator. It has invested substantial capital in the plant used to generate electricity and, unless the plant is nearly fully depreciated, price swings in gas transport of, say 10% to 20% either way is unlikely to change demand very much in the short term. Over the longer term, price will matter, but, more than our price in isolation. It will be the price of substitutes for gas, such as renewables, which matter. As these substitutes change in relative price, substitution away from gas generation plant occurs, at a pace which does not exceed the ability of the generator to effectively recover its invested capital and does not strand its own assets.

However, even this substitution does not happen in isolation. Renewable electricity, whilst it might compete with gas over a wide range of demand, cannot provide firm power, but rather relies upon the weather. This means that, at higher levels of market penetration, gas remains the cheapest system-wide solution to provide firming power and, absent of any technological change, the gas generator would be able to support much higher prices for gas and its transport at these levels of renewable penetration than it would be able to sustain where gas is competing more directly with renewables.

Added to these complexities in price are several non-price factors. Key amongst these is carbon pricing and/or carbon policy. Depending on carbon policy settings, whether these are reflected in carbon prices or not, our Shippers may need to move away from gas because using it would increase their own emissions, when policy settings do not allow this. Even if gas is the cheapest form of energy, they may be precluded from using it.

Note that many of our Shippers are multi-national companies. For these Shippers, it is not necessarily only Australian emissions targets and policies which bind, but also those in other jurisdictions. In other instances, our Shippers may be moving away from gas even where they are not required to do so by law, but because they have their own corporate net zero targets which may be part of their ESG settings, or may be due to other pressures, such as restrictions in borrowing if they fail to reach sufficiently low carbon settings; borrowing costs, rather than energy prices, could be sufficient to motivate a switch.

Additional to this are technological changes and plant changes. Our Shippers are not attempting to minimise their energy costs, but rather their total plant costs. In some cases, changing to a different form of energy might increase costs, but if it lowers overall plant costs, this may be acceptable.

Finally, there is a question of risk. Energy can sometimes be a crucial input in that if no energy is available then the entire plant shuts down and nothing is produced. However, it may not be a large part of the cost stack, but those costs are well below the revenue which can be earned (say because they are a low-cost minerals producer selling into a global market where prices are set by higher-cost competitors; a common occurrence for our Shippers). In these instances, risk comes into play; a Shipper may decide to stick with gas even where it is more costly because the replacement technology is less certain, and its failure could result in significant losses. Alternatively, it could adopt a competing technology when current plant is retired, even though gas is cheaper now because it believes that gas supply and price may be risky in the future; say because of carbon pricing, or domestic gas restrictions.

6.6 Our modelling approach

Our modelling approach to depreciation builds upon our work for AA5, on work undertaken for our distribution networks in Victoria and the ERA's most recent views on appropriate treatment of depreciation in its recent ATCO Draft Decision. Whilst our Draft Plan keeps the 2063 end date approved for AA5, as we do not believe the very long-term risk profile has decreased since then, the Draft Plan advances our approach to depreciation pathways to 2063 and has a stronger focus on our Shippers.

Our approach to depreciation also focuses on both of the risks noted above in that it:

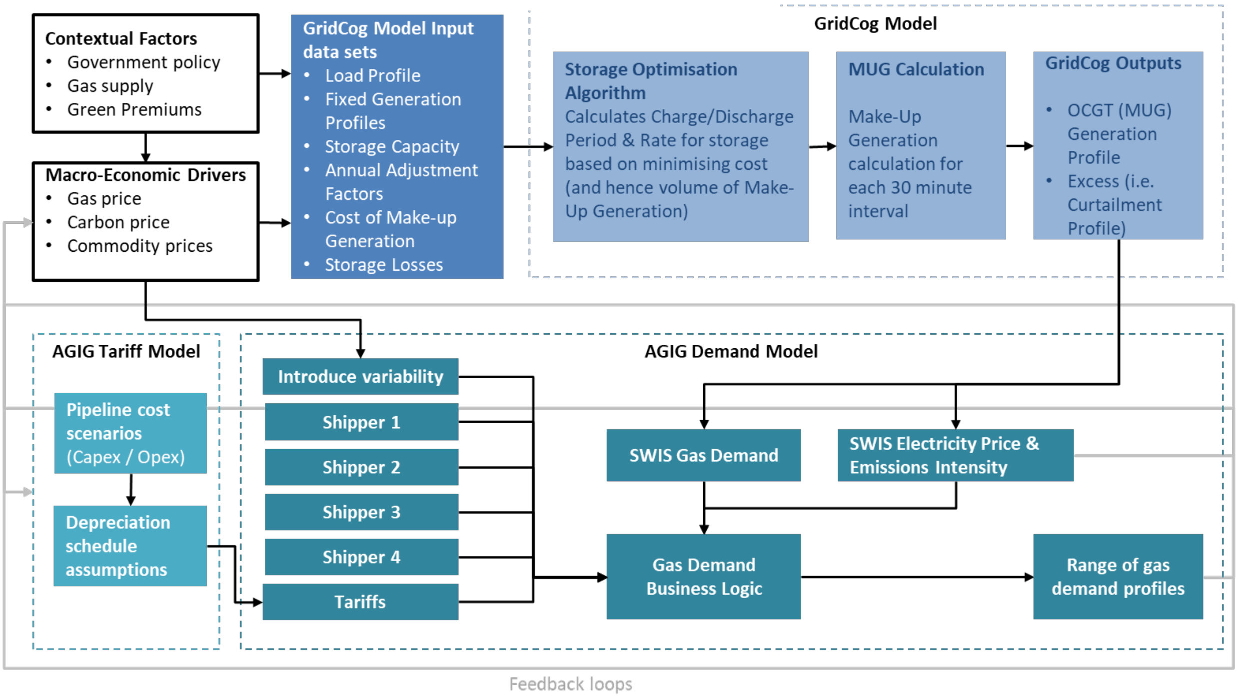
- aims to prevent remaining Shippers from suffering a high price shock if and when a Shipper ceases transporting gas altogether; and
- aims to lower the cost of the 'insurance' aspect of gas transport capacity rights.

To meet both of these risks, we focus on the price Shippers pay in a slightly different way. Rather than focus on the tariff itself, we focus on the 'price per GJ of gas actually used' (essentially total Shipper cost—incorporating both capacity and commodity charges—divided by throughput). In this manner, we can see the second risk noted in the introduction as it evolves, without losing sight of the first.

The modelling framework is a work in progress and has not directly informed the accelerated depreciation amount proposed in this Draft Plan, which is instead a placeholder while we engage in further consultation with Shippers.

The modelling framework is summarised in Figure 6.1.

Figure 6.1: Modelling framework Schematic



6.6.1 Model Mechanics

In the model, there are a number of driving factors which we have split into 'contextual factors' and 'macro-economic drivers'. The former are factors which take a discreet value with some probability (whether we know it or not), like policy settings. The latter are continuous variables, like price. These drivers then influence both our major Shippers directly and the SWIS in terms of their behaviour, in a demand model. Note that we have focussed on the four major Shippers plus the SWIS to simplify the modelling task, whilst still ensuring that we account for more than 80% of our total demand.

Note also that, because the SWIS is very complex, this is modelled in an optimisation package called GridCog by our expert advisors Carbon TP, whilst the behaviour of our major Shippers is modelled in an Excel model. Since it is very time-consuming to run GridCog, rather than run it each time we run a simulation in the model (see below) we instead choose from a set of representative GridCog model runs to match the given simulation based on input driver characteristics.

There is also a feedback loop between the SWIS and major Shippers so that if a major Shipper electrifies, this changes the load on the SWIS.

The other major part of the model is an extended version of the tariff building block model, which extends the regulatory building block model out to 2065 in five-year blocks. It is in this part of the model that we implement changes in depreciation.

The model is a simulation model; values are drawn from the ranges for all the driver variables and combined with tariffs from the extended tariff model and then fed into GridCog and the AGIG Demand Model to produce a demand response from the SWIS and major Shippers (respectively). This demand, multiplied by tariffs, determines our revenues, and there is a feedback loop whereby demand from one five-year AA is fed back into the tariff model to produce tariffs for the next AA. These feedback loops are crucial because demand depends on price, so we need to be able to simulate how demand changes when price changes because of the depreciation changes we have made.

The way the model is intended to work in practice is that we will run several hundred or thousand simulations, producing price paths through time. We will then pick a period in the future, say 2050, and look at the average price and the range around that average price, comparing both to current prices.

Where there is a large difference between modelled and current prices, indicating Shippers have faced a price shock from changes in demand between the present and that date, we will make changes to the depreciation profile in the tariff model. The way this is done is by 'tilting' the depreciation profile to allow for more depreciation in the near future and less in the distant future. This is an approach used as part of the recent Victorian Gas Distribution Access Arrangement reviews, where our modelling was accepted by the AER, and is an approach the ERA has suggested might be acceptable for ATCO (a Final Decision for the ATCO AA is expected in November 2024 and will inform our approach to depreciation in the Final Plan). We then look at the average price and range anew to see if accelerating depreciation has improved matters for Shippers.

It is important to note that what we *do not* do is attempt to optimise the depreciation profile. This is impossible given the complexity of the interaction between drivers and the general lack of certainty about the future. Rather, we use the modelling framework to test different potential depreciation profiles and choose one which improves the outcome for Shippers from a do-nothing approach.

As we start working with the model, we will refine our approach further, and continue to consult with Shippers and the ERA.

6.7 Summary

As the discussion above suggests, the modelling approach is a work in progress. For this Draft Plan, we need a placeholder value for accelerated depreciation. To get this placeholder value we have followed an approach analogous to the approach we have followed for demand in that we have used an amount for total depreciation (including ordinary regulatory depreciation included in Chapter 10, the residual results of the asset recategorisation undertaken in AA5 and accelerated depreciation) which is the same, in real terms as we used in AA5. This amount is $568 million, and of this, $113 million is accelerated depreciation. As we refine our modelling approach, we will refine the numbers and consult with stakeholders before finalising ahead of the Final Plan.

To aid the engagement process, we would welcome your response to the following questions:

Questions for consideration

2 **Do you agree that we need to consider accelerating depreciation to address future risks?**

3 **Is achieving stability in prices through the long term important?**

4 **Do you have any other feedback on our accelerated depreciation approach for AA6?**

7 Pipeline and reference services

The proposed pipeline and reference services for AA6 are generally consistent with those currently provided on the DBNGP.

IN THIS CHAPTER:

- **We have proposed pipeline and reference services generally consistent with those demanded in AA5**
- **Full haul, part haul and back haul services will continue to be complemented by a suite of non-reference services**

We offer various pipeline services to meet the needs of our Shippers (our direct customers). The regulatory framework requires that at least one pipeline service be categorised as a reference service.

Reference services are determined based on 'reference service factors' including demand, substitutability and the usefulness of the service in supporting access negotiations.

The reference services we propose for AA6 are consistent with those applied in previous AA periods; full haul, part haul and back haul services. The reference services form the basis for this Draft Plan.

The following sections outline the pipeline and reference services we offer. Details of the terms and conditions of our reference services will form part of our Final Plan to be submitted to the ERA by 1 January 2025. We will consult with Shippers in detail on terms and conditions as we develop our Final Plan.

7.1 Regulatory framework

Under changes to the *National Gas Rules* (NGR), published 21 March 2019, we are required to include a list of all pipeline services we can reasonably offer in a Reference Service Proposal at the start of the AA process, and specify those which are reference services.

In considering which services should be specified as reference services, the ERA is to have regard to reference service factors and the feedback of stakeholders.

The reference service factors (in accordance with NGR 47A(15)) 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 for all parties.

7.2 Stakeholder engagement

We published a Draft Reference Service Proposal (RSP) in August 2023 and shared our proposed reference and non-reference services and the rule requirements for reference services at our first Shipper Roundtable.

We received one written submission on the Draft RSP, which made various recommendations for changes to the proposed list of services. The main recommendations in this submission included:

- consolidating firm and interruptible services into two service offerings only;
- reclassifying our interruptible services as reference services;
- extending the Pilbara Service to include the Perth Basin; and
- reinstating pipeline storage services and data services that were no longer proposed to be offered.

We reflected on this feedback and our Final RSP was submitted to the ERA and published in December 2023, including our responses to these recommendations. We opted to retain our proposed list of pipeline services as presented in our Draft RSP, the reasons for which are summarised below. We noted that we could provide data and storage services if there was demand for the services.

Our reference services are all priced on an equivalent distance-factored basis (including T1 at 1,399 km), given the homogenous nature of the services. The distinction between the three is applied as a practical way to better define the specific extent and direction of services contracted for, whether they are full or part haul and forward or back haul.

Non-reference services are those that do not meet the reference service factors and are each tailored to meet specific Shipper needs. We did not propose any reclassifications or consolidation of service options in our RSP.

Extending the Pilbara Service to include the Perth Basin would significantly increase its cost and there was limited additional support for this option from Shippers.

Regarding other proposed changes of current reference services to non-reference services, there has been very low demand for both data services, which was a service to assist gas producers and marketers with gas allocations, and the pipeline storage service. Further, the change in operational dynamics on the pipeline mean that we can no longer offer pipeline storage as a firm service. Additionally, Shippers have access to alternative storage facilities such as Mondarra and Tubridgi.

The ERA published a notice on 9 February 2024, establishing its own consultation on the Draft RSP. It considered that we could still provide those services we proposed to remove from our offerings. The ERA posed six consultation questions in its notice, including:

- two questions on whether Data services, Storage services, and Seasonal, Metering/Temperature and Odorisation services should continue to be provided in AA6;
- two questions on the classification of our pipeline services as either reference or non-reference services; and
- two questions on our consultation process regarding the RSP.

We addressed each of these questions in our submission to the ERA's consultation.

In general, we submitted that our RSP is compliant with Rule 47A(1) as it was submitted and that the reasons for omitting the services in question are consistent with the test of 'reasonableness' that is required under the NGR (47A(1)(b)). However, as part of this submission we proposed that we continue to offer Data services to marketers and producers.

In addition, we noted the non-reference services we proposed, based on currently available information, will not meet the reference service factors for the entirety of the Access Arrangement period from 1 January 2026 to 31 December 2030. Therefore, we argued classification of these services as non-reference services remains appropriate, even with changing demand and operational dynamics on the pipeline.

We also held further Shipper Roundtables on key areas of our planning, including our proposed pipeline services and reference services.

Our Shippers have generally agreed it is appropriate to continue with the current three reference services in AA6.

The ERA received two submissions on its notice regarding our proposal, including our submission.

The ERA published its own Reference Service Proposal on 1 July 2024, accepting the Full Haul, Part Haul and Back Haul services continuing as the only three reference services for the DBNGP.

It also included both Data services and the Storage service in the list of pipeline services we can reasonably provide (classified as non-reference services). It did not accept that low demand or the difficulty we are likely to face in delivering a firm pipeline storage service were reasons to remove the services from our offerings. However, it did not require us to include other ancillary services already offered as part of contractual conditions (Seasonal, Metering/Temperature and Odorisation services) in our list of pipeline reference services.

Table 7.1: Reference services

Reference services
Full Haul T1 Service
Part Haul P1 Service
Back Haul B1 Service

7.3 Reference services

Consistent with our Reference Service Proposal and our offerings in AA5, we are proposing to offer three reference services in the AA6 period. These are outlined in Table 7.1.

The three reference services proposed reflect the reference service factors, by:

- being in high demand;
- being substitutable with other, similar pipeline services;
- forming the foundation of our demand forecasts and cost allocation;
- providing prospective users with an aid for use in access negotiations for non-reference services; and
- minimising cost and regulatory burden.

7.4 Pipeline services

Table 7.2 lists all the pipeline services to be offered in AA6 to current and prospective users on the DBNGP, including both our reference services and our non-reference services.

These include services subject to the availability of capacity (i.e. gas transportation services) and those subject to operational availability (data and storage services).

7.5 Summary

We propose that the reference services for the DBNGP in the AA6 period remain consistent with those applied in the AA5 period. This follows our direct engagement on the list of services and is consistent with the reference services accepted by the ERA in its own proposal. Most of our customers have also supported this approach.

Our AA6 Draft Plan has been developed based on the provision of the three reference services:

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

We shall also continue to offer other pipeline services as in AA5 (and listed in Table 7.2) and invite any current and prospective Shipper to discuss their specific requirements with our Commercial team.

Table 7.2: Pipeline services

Pipeline services	Service description
Reference Services (descriptions applicable to Reference and Negotiated Shipper Contracts)	
Full Haul T1 Service	Forward Full Haul (subject to available capacity) with outlet point downstream of CS9, regardless of the location of inlet point upstream of MLV31
Part Haul P1 Service	Forward Part Haul (subject to available capacity) with the inlet point upstream of the outlet point, regardless of the location of the outlet point, and is not a Full Haul Service
Back Haul B1 Service	Back Haul (subject to available capacity) service where the inlet point is downstream of the outlet point
Non-reference Services	
Spot capacity service	Allows access to gas transmission capacity on a day ahead basis where available via auction (subject to available capacity)
Pipeline impact agreement (PIA)	An agreement specified under the Gas Supply (Gas Quality Specifications) Act 2009 developed to allow gas producers to supply broader quality gas in Western Australia
Data service	A service developed to assist gas marketers in providing gas allocations on Shippers' behalf on the DBNGP (subject to operational availability)
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)
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. The services have a reservation charge but exclude T1, P1, B1 and spot capacity.
Pilbara service	The Pilbara Service is an interruptible transportation service on the DBNGP where deliveries are within the Pilbara Zone (between I1-01 and MLV31 includes I1-01 and MLV31)
Peaking service	A pipeline service where a Shipper can obtain additional peaking limits to those set in standard terms
Storage service	A Park and Loan service, permitting limited gas storage in the DBNGP, and/or taking additional gas from the DBNGP when required (subject to operational availability)
Backflow service (Ullage)	A bespoke capacity service where gas is required to be delivered to the Karratha Gas Plant

8 Operating expenditure

We are maintaining an efficient operating program for our customers in a challenging higher cost environment

IN THIS CHAPTER:

- **Our 'controllable' opex performance in AA5 is estimated to be $9 million lower than the benchmark allowance**
- **Our total opex forecast in AA6 is an increase of 12% on our AA5 performance, driven by the increase in labour and other costs we have experienced in the later years of AA5**
- **Despite higher costs, we are committed to maintaining the safe, reliable and high-quality service our customers value and demand in a prudent and efficient manner**

We incur operating expenditure (opex) to undertake activities that allow us to safely, reliably and efficiently operate and maintain the DBNGP. Opex also underpins our customer experience and our healthy, safe, engaged and skilled workforce.

Our hybrid top-down and bottom-up approach to forecasting opex for AA6 is consistent with the ERA-endorsed approach applied in AA4 and AA5.

The following sections outline this approach, key drivers of expenditure and our performance relative to benchmark in AA5. In addition, we outline how we ensure the opex we incur is efficient. All figures quoted are dollars of December 2024, unless otherwise labelled.

8.1 Regulatory framework

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.

Any forecast or estimate must be reasonable and the best forecast or estimate possible in the circumstance.

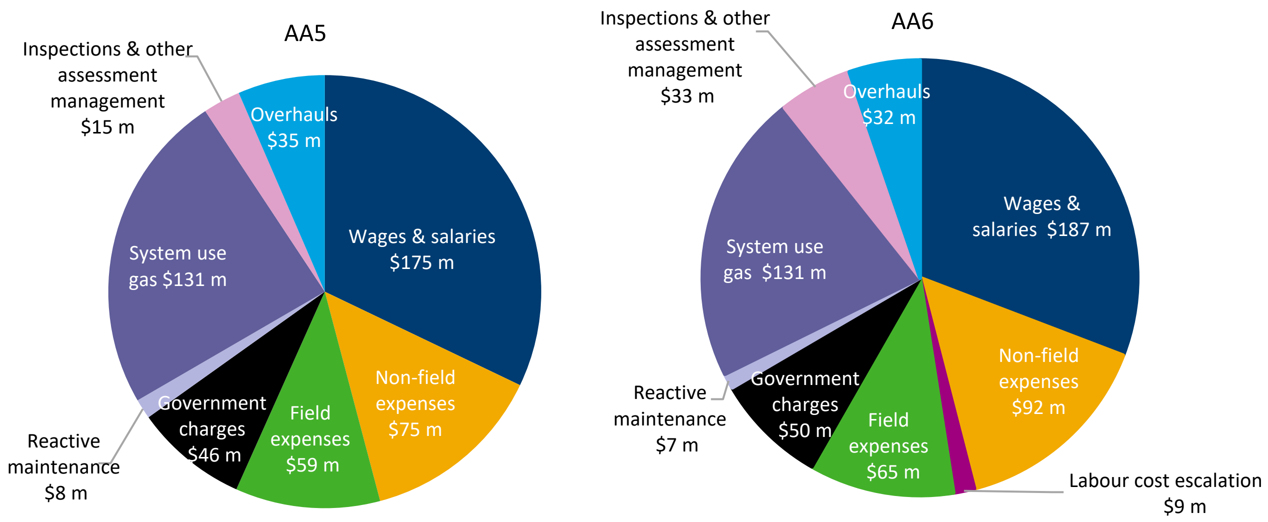
8.2 Overview

Our forecast opex for AA6 is $606 million over the five years. This is an increase of $64 million (12%) compared to our actual performance over the current AA5 (2021-25) period.

A tight labour market and other wage and salary expense pressures (such as the legislated requirement for higher superannuation contributions), as well as unavoidable increases in insurance costs, have contributed to a large share of the cost increases (accounting for $21 million and $5 million respectively).

The increase is also driven by higher 'inspection and other asset management' item costs (for critical inspection, safety, training and other asset management - related activities), which

Figure 8.1: Total forecast AA6 and AA5 opex by category ($million, Dec 2024)



represents cyclical expenditure needs aligned with our asset maintenance programs. Altogether the increase accounts for 28% of the higher opex.

We also have an uplift in our IT capability (accounting for 10% of the projected increase) to ensure we can continue to sufficiently address the operational risk to our business and meet customer and stakeholder technology-related needs

The forecast increases in insurance and IT expenses are evident in higher non-field expenses (see Figure 8.1).

8.3 Stakeholder engagement

We are committed to ensuring our Draft Plan is informed by effective stakeholder engagement. Chapter 5 of this Draft Plan summarises our engagement program to date and how we have used feedback to inform our plans.

In our second Roundtable meeting in Stage 2 of our stakeholder engagement program, we engaged on our proposed opex for AA6.

Shippers were informed about our approach to estimating opex for AA6, plus the reasons for expected higher opex in some categories. They had questions regarding some category costs, such as for system use gas and whether the Waitsia project would be factored into our estimates, which we have further considered.

In general, our engagement activities to date have reinforced how stakeholders highly value the current levels of service reliability and would be concerned if this was to change. There also appears to be general acknowledgement that the economy has presented some difficult cost pressures at this time.

We have reflected the feedback and insights gathered during our stakeholder engagement program so far. Accordingly, we have focused on maintaining current levels of system safety and reliability, and have planned essential pipeline and station inspection and other asset management related projects to ensure our performance continues in these areas. We have also ensured our insurance and IT requirements sufficiently address current risks in our operations.

8.4 How we develop our opex forecast

There are two different methods we use to forecast our opex over AA6. For most opex categories, we have applied a 'base year roll-forward' approach. For SUG, turbine and gas engine alternator (GEA) overhauls, asset inspections, other minor pipeline works, and health and process safety initiatives, we use a bottom-up approach. This approach considers the quantity and cost of activities required over the five years. This hybrid approach is consistent with the ERA's preferred forecasting method applied in AA4 and AA5.

Under the 'top-down' component of our approach, the latest revealed cost is used as a base for future costs. The latest revealed costs by the time prices are set for AA6, and therefore our 'base year', is 2024.

As we do not have revealed costs for 2024 yet, we have used our

2024 opex forecast, with consideration of adjustments for any costs to be incurred in 2024 which are not expected to be incurred in AA6, and likewise for any costs that are not incurred in the 2024 base year but are expected to be incurred from 2026. An example of where costs have needed to be further adjusted for an expected increase between 2024 and 2026 is insurance and this is explained in more detail below.

We will update our base year as actual opex information becomes available. The forecast to be included in our Final Plan in December will comprise nine months of actual opex and three months of budget opex.

The next step in the base year roll-forward approach is to consider any cost increases or decreases that are applicable in AA6 due to changes in legislation, regulatory obligations or new activities. These are referred to as 'step changes'.

We are proposing one small step change of $200,000 in 2026 for additional IT expenses associated with implementing our new Transmission Billing System (TBS), as explained in Chapter 9. This new system will ensure compatibility with our customers' needs and improve their experience regarding our accounts process. Finally, real cost escalation is applied to those cost categories which grow at a faster rate than inflation. Consistent with the approach in AA5, we have real cost escalation to labour costs.

We then add our separate forecasts of:

- SUG, which is a function of quantity required and forecast price;
- turbine and GEA overhauls, which is a function of unit run hours and costs per unit; and
- the value of asset inspections, other minor pipeline works and small health and process safety initiatives, which are a function of the number of activities/initiatives required and cost per activity/initiative.

8.5 Key drivers in AA6

We will maintain our strong safety, reliability and customer service, within our opex forecasts in AA6.

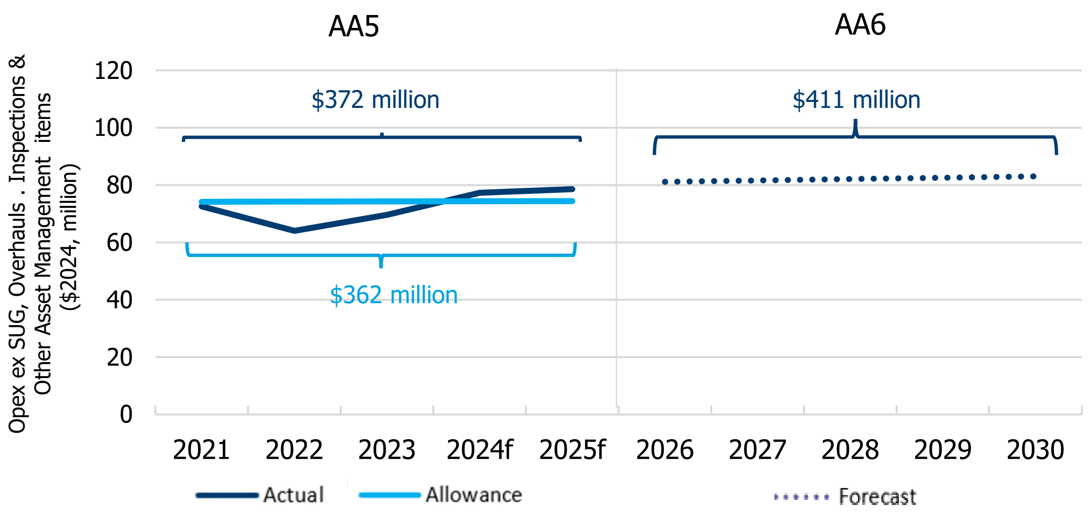
8.5.1 Delivering for customers

Our opex proposal delivers for customers by ensuring we are funded to undertake asset maintenance as required by our asset management plans, and activities to maintain our strong safety, reliability and customer service performance. Our customer interactions will continue to be guided by the customer experience aspirations we have agreed to.

8.5.2 A good employer

Our opex proposal will help us provide a healthy, safe, engaged and skilled workforce. Our non-field expenses include workplace health and safety programs and our field expenses include

Figure 8.2: AA5 and AA6 forecast 'controllable' opex performance ($million, Dec 2024)



employee and contractor training and development initiatives.

8.5.3 Sustainably cost efficient

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

- delivered real controllable opex savings of around $9 million compared to our approved allowances for AA5 (excluding SUG, overhauls and 'inspections and other asset management' items); and
- kept our 'controllable' opex in AA6 at similar levels to that incurred towards the end of AA5 (see Figure 8.2), when significant cost pressures have arisen in the market.

8.6 Our AA6 opex forecast

The following sections outline each of the elements of our AA6 opex forecast. Towards the end of the section, we present our opex forecasts by category in Table 8.4.

8.6.1 2024 base year

We are proposing calendar year 2024 as our Base Year for forecasting much of our AA6 opex. This is the penultimate year of the current AA period. This is consistent with regulatory practice across Australia.

Our Draft Plan includes a forecast for 2024 opex. We will update this with nine months of actuals and three months of forecast when we submit our Final Plan to the ERA in December this year.

By the time the ERA makes its Draft Decision, we will be able to provide a full year of actuals for our 2024 Base Year. This is in line with ERA expectations that the latest actual costs will be applied for the base year roll-forward approach for opex.

We are proposing the same opex categories as AA5, these are:

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

We are confident our 2024 base year opex is prudent and efficient because:

- it is based on actual operating expenditure over 2021-23; and
- it is subject to the efficiency factor mechanism.

8.6.2 Adjustments to base year opex

As mentioned in Section 8.4, we adjust our base year opex where it is not reflective of efficient costs likely to be incurred in a typical year.

We take a five-year average of our consulting costs, rather than the 2024 base year, due to the volatility that is often experienced in this cost category. This is consistent with the approach approved by the ERA in AA5.

We have also directly estimated insurance costs in 2026 given additional costs anticipated from 2024. This is a different approach to the rolling six-year average of our insurance costs which we estimated for AA5, based upon the cyclical nature of insurance markets.

The anticipated higher costs (of $4.8m) are due to new insurance for cyber security (given the increased risk associated with cyber security threats) and higher premia in the market. The higher premia are due to the combined effect of a claim by the business in the current period, asset revaluations and increased risks in the market. Our main insurance provider has provided an assessment report explaining the current cost pressures on the DBNGP for insurance.

8.6.3 Opex step changes

We adjust our AA6 opex for any 'step changes' in our costs resulting from changes in legislation, regulatory obligations or new activities.

At this stage, we have included one small step change of $200,000 in 2026 for additional operational costs associated with running the planned new Transmission Billing System.

We will continue to review our IT and insurance expenditure needs over the next few months as more information becomes available for our final proposal.

8.6.4 Input cost escalation

We make further adjustments to our AA6 opex to account for costs that are increasing at a faster rate than inflation (real cost escalation).

We have applied real cost escalation of 1.11% per annum to our labour costs.

Consistent with the approach previously approved by the ERA, the appropriate labour cost escalation is calculated by:

- taking the Western Australian Treasury Wage Price Index (WPI) forecasts for the upcoming period (2024-25 to 2027-28 given forecasts currently available), less

- the benchmark inflation estimate for the upcoming period (2024-25 to 2027-28), based on the WA Treasury's Perth CPI forecasts, plus
- the forecast premium of the Australian WPI for the Electricity, Gas, Water and Wastewater Services (EGWWS) Industry over the WPI for all industries, calculated by the Australian Bureau of Statistics (ABS). We have applied the average difference over the ABS series from 1998 to estimate this premium given the stage in the wages cycle and because KPMG's latest forecasts for real wages growth in the utilities industry[1] support this level of projected growth. We consider that the risk to the KPMG national forecasts is on the upside since WA's industry-based wages growth could be higher with strong competition for labour from the mining sector.

Table 8.1 provides the values used in this calculation.

Table 8.1: Annual labour cost escalation estimate for AA6

Measure	Value
WA Treasury WPI forecast	3.31%
Less Inflation	2.63%
Plus EGWWS WPI premium	0.44%
Annual labour cost escalation	**1.11%**

8.6.5 Output growth

We are not proposing to apply an output growth factor to our base year roll-forward 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.

8.6.6 Productivity growth

We have considered whether there should be an adjustment to capture the benefits of any potential future productivity gains made by the business during the next AA period.

The necessary dataset for measuring historic industry productivity performance through econometric modelling is not available for gas transmission. Therefore, we have relied upon indicators such as output and capex growth to guide our assessment of the potential for productivity gains over the period.

We consider that the output-growth and scale forecasts over AA6 in aggregate are weak, and as such, are unlikely to materially drive improvements in our productivity.

As discussed in Chapter 13, there is slightly lower throughput forecast compared with the estimates for AA5.

In addition, as outlined in Chapter 9, our forecast capex program is focused on network-sustaining activities, rather than growth activities that could create increasing returns to scale.

A tight labour market and skills shortages will continue to characterise our industry, as identified by KPMG[2], and labour market conditions, rather than productivity improvements, will drive real wages growth.

For these reasons, we have not incorporated a factor for productivity improvements in our opex forecasts.

8.6.7 System use gas

We are forecasting $130.9 million in SUG costs in AA6. This is broadly on par with our estimated SUG costs in AA5 ($Dec2024). We have forecast lower throughput than in AA5 however we have also assumed higher gas prices compared to when we last tendered for our SUG requirements in 2019.

As mentioned above at Section 8.4, 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. At this stage, we have not changed the hydraulic modelling inputs assumed in AA5 for our SUG forecasts. However, we have applied the throughput forecasts as in Chapter 13.

Our forecast price (between $10/GJ to $12/GJ) is based on current market indications for securing gas to meet our forecast

[1] KPMG, *Wage Price Index Forecasts*, AER, 8 April 2024. See Table 2 (National All Industry WPI and National Utilities WPI) and page 17 (which states "Jobs and Skills Australia forecasts only 11,600 new employees will enter the (utilities) industry (nationally) by 2028, the lowest of all industries."

[2] See footnote 1.

SUG quantity requirements in AA6.

At this stage, we have not included any ongoing operating cost reductions from the Compressor Reduction Project which is currently being investigated for feasibility (and explained in Chapter 9). Should we choose to progress this project, we will incorporate the impacts into our modelling for our Final Plan.

8.6.8 Turbine and GEA overhauls

We are forecasting $31.9 million in turbine and GEA overhauls in AA6.

Our turbine and GEA overhaul costs are a function of unit run hours and estimated cost per unit.

In AA6, we will continue to include turbine and GEA overhauls as opex consistent with the ERA's preferred treatment of these costs.

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. In considering overhaul requirements we look closely at the current and projected utilisation of our compressors on the pipeline.

Based on current run hours and utilisation rates for turbine units we are forecasting to overhaul five units in AA6 with one in each of the five years. We have also allowed for one additional overhaul for a premature failure of one of our turbine units in AA6, as such failures have occurred in both AA4 and AA5.

GEA overhauls

GEAs are the primary power source 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 25 GEA overhauls in AA6, spread relatively evenly across the period, at an average cost of $1.0 million each year.

In AA6, we have forecast $33.0 million across these items, including $10.8 million on meter and compressor station inspections and $13.8 million on pipeline and mainline valve inspections. The need for new station inspections include:

- building and structural inspections aligned to our AMP requirements;
- inspections of storage tanks not classified as pressure vessels in accordance with relevant Australian Standards; and
- Rotor bundle, vent attenuator and insulation inspection, repair and replacement based on condition assessments that they have reached their end of life.

Figure 8.3: A major turbine

8.6.9 Inspections and other asset management

For AA5, we estimate delivery of $15.2 million of asset inspections, other minor pipeline works and small health and process safety initiatives as part of opex.

The pipeline and mainline valve inspection planned expenditure includes $8.0 million on an intelligent pigging program, which is on an 8-yearly cycle, commencing 2028.

The need for these inspections to ensure the safety and integrity of the pipeline is consistent with our regular maintenance regime for our assets. We are also proposing

$6.6 million on a range of new asset management programs to further ensure safety and reliability of our pipeline in alignment with our asset management plans, including:

- A gas measurement software upgrade;
- Crane and lifting equipment inspections;
- An Equipment obsolescence program; and
- An Artificial Intelligence investigation program.

Lastly, we propose $1.2 million for asset decommissioning activities, where assets are no longer fit for purpose in service delivery, and $600,000 for HSE initiatives.

For the proposed expenditure for Inspection and Other Asset Management activities, we are preparing business cases to include in our Final Plan to the ERA in December.

8.7 How we will 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 in our business. This framework ensures we are making sound decisions for our customers, our stakeholders and our business.

8.7.1 Our Asset Management Plan, maintenance regime and Safety Case

Our overarching Asset Management Plan (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. It sets out the asset maintenance regime applied to the DBNGP which supports our vision to deliver for customers, be a good employer and be sustainably cost efficient.

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 equipment. These factors drive 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 Asset Management Plan 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.

We are incentivised to be efficient with the operation of the efficiency factor mechanism which is applied to our opex performance, as outlined in Chapter 12.

The *Work Health and Safety Act 2020* and associated *Work Health and Safety (Petroleum and Geothermal Energy Operations) Regulations 2022* (WA) require us to submit our Safety Case to the Department of Energy, Mines, Industry Regulation and Safety every five years. Our Safety Case is the primary document outlining how we operate the DBNGP in compliance with our obligations under the Act, Regulations and our operating licences. It demonstrates the adequacy of the systems, processes and procedures in place to support us in safely operating the DBNGP.

It also describes the hazards associated with operation, and controls in place to minimise the risk so far as is reasonably practicable. The maintenance requirements set out in our AMP ensures 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 adequately control the risks of our operations.

8.7.2 Financial governance

We regularly report our forecast and actual opex through our internal budgeting processes and financial performance reporting. Our performance against the prior year spend and approved regulatory allowances is heavily scrutinised, 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 outperform 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).

8.7.3 Procurement

All procurement activities are subject to our Contracts and Procurement Policy, which superseded our previous Purchasing Policy in December 2023. This policy ensures we continue to carry out these activities in an efficient, cost effective, confidential and ethical manner by:

- Ensuring our procurement meets the highest standards of business ethics and integrity; and
- That our contracts and purchases represent value for money.

The Procurement group is the owner of the Contracts and Procurement Policy and is responsible for ensuring it is up to date and appropriately applied in the business.

Table 8.2 outlines the minimum purchasing requirements which must be met, dependent upon the value being procured. All procurement activities exceeding a value of $100,000 must be competitively tendered to at least three vendors, over $500,000 requires at least four vendors.

Our Delegation of Financial Authority covers all financial transactions within our organisation. It outlines the level of financial authority at each level

Table 8.2: Minimum purchasing requirements

Value	Minimum Requirement
<$100k	One written quotes
$100k-$500k	Three written quotes
>$500k	Tender from four vendors

Table 8.3: Delegation of Financial Authority

Role	Budgeted	Un-budgeted
CEO	$5m	$5m (if it fits within overall approved budget)
GM	$500k	Nil
Manager E&OP	$100k	Nil
Project Manager	Nil	Nil

within our organisation, depicted in Table 8.3.

Only the CEO has financial delegation to approve funds for unbudgeted initiatives, and then only if it aligns within the overall approved budget. Anything over $5 million must have Board approval to proceed. This approach provides strong financial controls and governance in the delivery of prudent and efficient opex.

8.8 Our performance in AA5

We are forecasting $543.6 million in opex in AA5. Our "controllable" opex i.e., opex excluding those expenses dependent on throughput - SUG and GEA/turbine overhauls - as well as the inspections and other asset management items, is $362.2 million, which is $9.3 million below our approved allowance for these expenses in AA5. This reflects continued efficiency by AGIG under challenging operating circumstances.

Our total SUG costs are $27.2 million (26%) above our allowance of $103.6 million. As described above at 8.4, our SUG costs are a function of quantity required and price. The main driver for higher SUG costs in AA5 has been higher full haul throughput than forecast (which increases the quantity of SUG required).

Our Turbine and GEA overhauls are estimated to be $4.2 million (14%) above our allowance of $31.2 million in AA5.

This outcome is despite a premature failure of a turbine being within the warranty period such that we avoided the replacement cost for this unit. The higher required expenditure is because of:

- higher full haul throughput than forecast (which increases the run hours required across our fleet of turbines and gas engines, and therefore accelerates the time taken to reach the defined run hour parameters for overhauls);
- air freight costs for transportation of turbines;
- air filtration system costs not budgeted for; and
- higher unit prices in the market.

Our Wages and Salaries are estimated to be $4.0 million (2%) higher than the allowance. This is largely due a lower allocation of labour costs from opex to capex and other areas of the business from 2024.

The COVID pandemic has impacted our Field expenses in 2021 and 2022. These have been below the allowance in AA5 over the five years by $8.9 million (13%). The Government charges and Reactive maintenance costs we have incurred have also been lower than the benchmark – by $5.1 million (10%) and $2.5m (24%) respectively – the latter due to the improved reliability of the pipeline services though our planned asset maintenance program.

Non-field expenses are $3.2 million (4%) higher than our allowance due, in part, to critical cyber security measures as outlined in Chapter 9. In addition, we are facing higher insurance and other supplier costs across the network.

We have also incurred higher 'inspection and other asset management' costs (by $2.8 million (23%) with new projects for the replacement of critical spares and the development of essential training modules for process safety, as well as additional costs associated with water bath heater inspections at three metre stations.

8.9 Summary

Our forecasts for opex in AA6 are summarised by category in Table 8.4.

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

- We have adopted the same opex categories as in AA5.
- We have applied a base year roll-forward approach for most categories of opex.
- Our 2024 opex forms the base year and will be updated for actuals as they become available (our Final Plan forecast will comprise nine months of actuals and three months of forecasts).
- We have adjusted our base year for average consulting costs given the potential for volatility in these costs year to year, consistent with the approved approach in AA4 and AA5.
- We have adjusted the 2024 estimate for insurance costs to forecast requirements in AA6.
- One small step change for new Transmission Billing System running costs is included in 2026 IT expenses.
- Real cost escalation of 1.11% per annum has been applied to labour costs using the real cost escalation methodology approved by the ERA in AA5, supplemented by our evidence-based forecast of an industry-based wages growth premium.
- We forecast similar SUG costs as in AA5 with the higher weighted average gas price that we expect to achieve

Table 8.4: AA6 opex forecasts by category ($m, Dec2024)

Category	2026	2027	2028	2029	2030	AA6 Total
Controllable opex:						
Wages and salaries	38.2	38.6	39.0	39.5	39.9	195.2
Field expenses	13.0	13.0	13.0	13.0	13.0	65.2
Non-field expenses	18.5	18.5	18.6	18.6	18.7	93.0
Government charges	10.1	10.1	10.1	10.1	10.1	50.3
Reactive maintenance	1.4	1.4	1.4	1.4	1.4	6.8
Controllable opex total	**81.1**	**81.6**	**82.1**	**82.6**	**83 .1**	**410.5**
Other opex:						
System use gas	22.4	27.2	27.2	27.1	27.0	130.9
GEA & turbine overhauls	5.6	9.6	5.6	5.6	5.6	31.9
Inspections & other asset management	4.4	4.2	10.2	9.6	4.6	33.0

across our SUG supply contracts offset by lower anticipated throughput.

- Expenditure on inspections and other asset management activities of $33.0 million is also planned, to be supported by business cases.

To aid the engagement process, we would welcome your response to the following questions:

Questions for consideration

6 **Do you support our approach to forecasting opex? Is there sufficient information to understand our proposals and the basis of the costs included?**

7 **Do you support our proposed input cost assumptions? If not, why?**

8 **Do you think the forecast level of opex is prudent and efficient, particularly given the current cost environment?**

9 **Do you have any other feedback on our opex forecast for AA6?**

9 Capital expenditure

Our proposed capital expenditure will enable us to continue our strong safety, reliability and service performance into AA6 with an ongoing focus on reducing our emissions.

IN THIS CHAPTER:

- **How we have managed our capex program in AA5**
- **Our stay-in-business capex forecast for AA6 including:**
  - **Continuation of existing programs including compressor stations, meter stations and IT expenditure**
  - **Installation of gas chromatographs to accurately measure gas injections from new producers**
  - **Upgrades to accommodation along the pipeline including to reflect our changing workforce**
  - **Projects to deliver reduced emissions from the operation of the pipeline, including a potential compression reduction project which will sustainably reduce operating costs into the future**

We incur capital expenditure (capex) to ensure the ongoing safe and reliable supply of natural gas to WA industry, businesses and homes every day.

Our bottom-up approach to forecasting capex for AA6 is consistent with our approach in previous periods, with a strong emphasis on meeting the requirements of our Safety Case, Asset Management Plans (AMPs) and Risk Management Framework.

The following sections outline our approach to forecasting capex and the key drivers and outcomes we will deliver in AA6. We will describe how we will continue to deliver our capex efficiently and how we have performed in AA5. All values quoted are dollars of December 2024, unless otherwise labelled.

9.1 Regulatory framework

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.

Forecast capex must also satisfy at least one of several criteria under Rule 79 of the NGR, which include expenditure to maintain or improve safety, maintain integrity, comply with our regulatory obligations, meet demand on the pipeline or where expenditure generates economic value. Recently, a further criterion for expenditure assessment was introduced, which requires regard for how proposed expenditure can help meet a jurisdiction's emissions reduction target.

9.2 Overview

We categorise our capex as either:

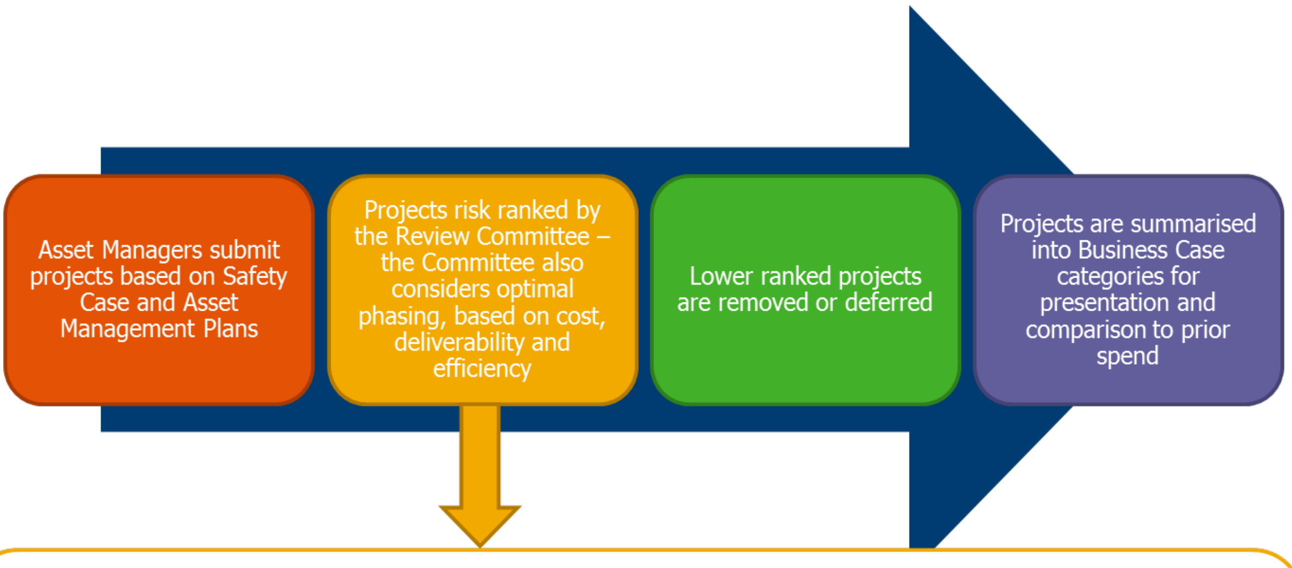
- stay-in-business capex— which maintains or improves our ability to deliver the current quantity of services our customers demand; or
- expansion capex— which is required to increase the quantity of services we can deliver to our customers.

In previous periods many pipeline assets have been refurbished rather than replaced and will reach the end of their technical life in AA6. This necessitates replacement in the next AA period to maintain the safety and integrity of the Dampier Bunbury Natural Gas Pipeline (DBNGP).

Our forecast capex over 2026–30 is $413 million driven by the need to:

- undertake preventative works and repairs to protect compressor stations from corrosion and safety hazards, conduct hazardous area rectifications and increase physical security on compressor stations (Compressor Stations Business Case, $48 million);
- install new gas chromatographs in response to changing gas flow dynamics driven by new sources of gas (Meter Stations Business Case, $8 million);
- purchase spare meters to allow their recalibration, ensuring billing accuracy (Meter Stations Business Case, $4 million);
- renew end-of-life main line valve equipment, repair and undertake preventative works on the pipeline to protect against corrosion, conversion of unpiggable mainline south to piggable (Pipeline and MLV Business Case, $29 million);
- replace an increased number of Closed Circuit Vapour Turbines (CCVTs) due to them becoming obsolete as a result of cessation of vendor support (19 replacements compared to 5 in the current period) (Pipeline and MLV Business Case, $8 million);
- SCADA hardware and software upgrades (Operational Technology Business Case, $15 million);
- renovate original accommodation facilities at compressor stations to ensure that they are fit for purpose

Figure 9.1: Summary of our capex planning process and operational risk matrix



RISK MATRIX

Frequency	Impact: Catastrophic	Major	Severe	Minor	Trivial
Frequent	Extreme	Extreme	High	Intermediate	Low
Occasional	Extreme	High	Intermediate	Low	Low
Unlikely	High	High	Intermediate	Low	Negligible
Remote	High	Intermediate	Low	Negligible	Negligible
Hypothetical	Intermediate	Low	Negligible	Negligible	Negligible

DBP People
Environment
Asset Damage
Loss of Supply
Outrage

and properly accommodate all of our employees as our field workforce demographic changes (Compressor Stations Accommodation Business Case, $13 million);

- replace obsolete compressor unit control systems which are over 15 years old and no longer supported by the manufacturer (Compressor Package Control System Replacement Business Case, $18 million);
- purchase tools for operations, capital delivery and emergency response (Tools Business Case, $3 million);
- maintain our OneERP software with major and minor upgrades (IT Sustaining Applications Business Case, $7 million);
- implement software and hardware to improve field mobility for our transmission operations staff (Field Mobility Business Case, $7 million);
- implement a fit for purpose Contract Management System to ensure that our customers are billed in a timely and accurate manner (IT Sustaining Applications Business Case, $2 million);
- complete looping of the pipeline to reduce compression with a view to locking in a sustainable reduction in operating costs and decommissioning one or more compressor stations (Compression Reduction Project, $123 million);
- implementation of efficient power generating equipment and fugitive emissions tracking to reduce scope 1 emissions (Efficiency and Decarbonisation, $5 million)
- replace IT hardware including laptops and switches and consolidate existing Data Centres (IT Sustaining Infrastructure Business Case, $15 million); and
- undertake ongoing replacement of vehicles and civil equipment (Fleet and Civil Equipment Business Case, $13 million).

The business cases for these projects will form part of our Final Plan, which will be submitted by 1 January 2025 and will provide detailed justification for the proposed expenditure.

In AA5 we forecast capex of $210 million, which is $27 million above our approved allowance, driven by the need to:

- replace, repair and undertake preventative works on our compressor stations ($41 million);
- replace a large number of end-of-life metering assets ($18 million);
- replace our northern communications system ($37 million);
- replace and refurbish pipeline and main line valve assets ($16 million);
- replace compressor unit control systems along the pipeline ($17 million);
- maintain a stable set of Information Technology applications that is current and fit for purpose ($28 million);
- refurbish/renovate original compressor station accommodation ($4 million); and
- invest in IT security ($2 million).

Our AA5 capex program has been adversely impacted by the COVID pandemic, which disrupted global supply chains. The mismatch between demand and supply has seen both materials and contractor labour costs increase significantly. Higher costs are demonstrated by the performance of producer price indexes (PPIs) in Australia since March 2020 (with many industry categories exceeding consumer price inflation over this period) and various public reports on current cost pressures in the economy.[1]

These increases have been particularly felt in Western Australia, which closed its borders for almost two years during the pandemic. Constrained supply of contractor labour and materials led to rising costs during AA5. In response we prudently deferred some projects and insourced where possible to ensure our expenditure is prudent and efficient. We explain these measures in more detail in Section 9.8.

[1] Examples are: Growth in the ABS PPI (Original) for the Oil and Gas Extraction industrial subgroup was 50% above the CPI from March 2020 to March 2024 (ABS, 6427.0 Producer Price Indexes, Australia, March 2024, Table 13), Chamber of Commerce and Industry WA (CCIWA) Business Confidence report (https://cciwa.com/business-pulse/1-in-5-businesses-at-risk-of-closing-downsizing-cciwa-report/) and AI Group (https://aigroup.com.au/news/media-centre/2024/untamed-inflation-puts-interest-rate-rises-back-on-the-agenda/).

9.3 Stakeholder engagement

At the Shipper Roundtables we engaged on key areas of our planning, including our proposed capex.

Our Shippers were broadly comfortable with our approach and high-level program in AA6. They asked various questions, including in relation to:

- providing more details on aspects of our capex plans;
- whether the compression reduction project would affect the capacity of the DBNGP and how it would potentially affect other business cases;
- whether the compression reduction project would reduce DBNGP emissions;
- our intention to install gas chromatographs to monitor the specifications of gas entering our pipeline; and
- how we deal with changing business needs during an AA period.

They also told us they highly value current levels of reliability and would be concerned if these were to change.

In relation to the Compression Reduction project, we confirmed there would be emissions reductions through the reduced use of compressors, which is one of the project benefits.

We advised that we are undertaking projects to reduce emissions, such as using solar power to operate some main line valves and that we are investigating other projects to reduce emissions, such as reducing the venting of methane along the DBNGP. Further information on the feedback we have received from stakeholders can be found in Chapter 5.

The feedback and insights gathered through our Shipper Roundtables are reflected throughout our forecast capex, particularly in the information we have provided on key areas of increased spend, project governance and procurement, and our performance in AA5.

9.4 How we develop our capex plans

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

The programs and projects in our capex plan are built up from our Asset Management Plans (AMPs) and Safety Case. Some of these are continuing programs of work we undertake, such as dry gas seal and valve replacements, hardware and software upgrades and cathodic protection. Others are discreet projects such as the Compression Reduction project, replacement of gas engine and compressor unit control systems and turbine exhaust replacement.

Projects and programs are proposed by our Asset Managers and considered by our Review Steering Committee. This Committee considers the drivers of proposed projects, reviews options analysis presented by Asset Managers and determines 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 Regulatory Business Cases for consideration, comparison to prior spend and full options analysis. Lower ranked projects are deferred.

This is an ongoing process which will be completed by the time of submission of the Final Plan later this year. Importantly, Shippers and stakeholders can provide feedback on our draft capex plans in response to this Draft Plan in writing or in Shipper Roundtables. We may also explain in more detail certain Business Cases prior to our Final Plan, such as the Compression Reduction project.

More information about our project governance is provided below in Section 9.7.

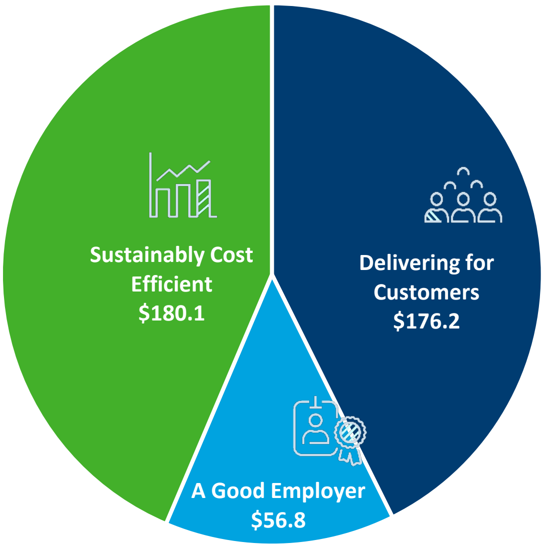
9.5 Key drivers

Our capex in AA6, depicted in Figure 9.2, aligns with the pillars underpinning our Vision, being:

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

43% of our total capex in AA6 is focussed on delivering for customers, 44% is focussed on being sustainably cost efficient with the remainder (13%) on being a good employer.

Figure 9.2: Total AA6 capex by driver ($million, Dec 2024)



9.5.1 Delivering for customers

We will invest $176 million on projects and programs that will deliver for customers. We will maintain our strong safety and reliability performance, and provide a modernised customer experience.

9.5.2 A good employer

We will invest $57 million into projects and programs in accordance with our vision to be a good employer. We will maintain strong health and safety performance, continue our refurbishment of original compressor station accommodation to reflect our changing workforce and redevelop our Jandakot facility.

9.5.3 Sustainably cost efficient

We will invest $180 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. We are also in the early design phase of the Compression Reduction project which aims to sustainably reduce operating and capital expenditure into the future and in turn reduce emissions.

9.6 Key projects and programs in AA6

The following sections provide some further detail on some of the key projects and programs we will deliver in AA6.

9.6.1 Compressor stations

Compressor stations are integral to the safe and reliable delivery of gas. There are a total of ten compressor stations along the DBNGP, each with multiple compressor units.

Compressor units are run based on the requirements of our customers and their operation must be ramped up or down quickly to meet these needs.

The key driver of the compressor stations program is delivering for customers, particularly in terms of public safety and reliability. The proposed program covers the following areas:

- the renewal of end-of-life rotating plant (dry gas seal replacement, vibration monitoring totalling $3 million);
- upgrading of working at height equipment and structures to comply with current Australian Standards ($4 million);
- repair, rectification and preventative works that protect from corrosion ($6 million);
- painting of facility above ground ($6 million) and refurbishment of below ground pipework ($7 million);
- replacement of air conditioning at compressor stations CS1–CS8 ($2 million);
- replacement of water bath heaters with electric heaters ($3 million); and
- hazardous area rectifications ($1 million), electrical protection integrity testing

($2 million) and increased physical security ($1 million).

9.6.2 Compressor unit control systems

Compressor unit control systems provide critical safety and control functions by monitoring the turbine compressors along the DBNGP and optimising system efficiency by enhancing compressor function. When compressors are not operating optimally, pipeline integrity can be impacted, as can our ability to fulfil our contractual obligations to customers.

The compressor units are operated remotely from our Perth control room. 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-pressurisation.

The control systems have reached the end of their technical life and are no longer supported by the manufacturer. We have implemented a staged replacement approach for compressor unit control systems to ensure obsolete hardware is changed in a timely manner without affecting the safe operation of compressor units. During AA5, we will deliver the majority of the program.

In AA6 we will replace five units at a total cost of $18 million. The key driver for this work is delivering for customers in terms of public safety and reliability. The new control systems will also allow us to utilise the new control optimisation package that has been developed by our key supplier of compressor units.

9.6.3 Meter stations

This ongoing capital works program ensures metering facilities continue to operate safely, reliably and within acceptable risk tolerances. Ongoing investment is also necessary to meet the gas delivery, quality and remote operability requirements as specified by our commercial agreements and relevant legislation such as Petroleum Pipelines Act 1969, the Work Health and Safety Act 2020 and Gas Supply (gas quality specifications) Regulations 2010.

Maintaining the operation of meter stations is an ongoing project which combines refurbishment pipework, heaters, pressure control valves, odorant injection equipment and replacement of gas measurement equipment (meters and flow computers) depending on their age and performance.

Routine inspections are required to maintain asset performance:

- The first project is to install gas chromatographs (GC) at a cost of around $8 million. The GCs are required at strategic locations to meet regulatory obligations regarding gas quality and the changing flow dynamics of the pipeline. New GCs will be installed at inlets where there is currently no GC installed (KGP, Wheatstone, Mondarra) and will replace existing GCs at other sites (CS6 and CS9). This will ensure we can meet the gas delivery requirements as specified by standard shipper contracts (including a contractual standard of 98% uptime), reference service contracts, relevant legislation and regulatory instruments.
- Purchase of spare meters ($4 million) will enable working meters to be swapped out, calibrated and recertified so that meters are accurately recording flow usage. This is compliance driven as there is an increasing focus on measurement, with more accurate measurement in turn leading to more accurate billing.
- Continuation of our 35-year replacement program for fuel gas heater trains ($3 million). Fuel gas heater trains ensure safe and efficient fuel supply by regulating gas pressure and flow. We replaced two fuel gas heater trains in AA5 and we need to continue this program into AA6.

9.6.4 Pipeline and MLV

This work program ensures that our Pipeline and Main Line Valve (MLV) assets are operating safely and reliably and falls into three categories:

- replacement of end-of-life electrical control and instrumentation (ECI) equipment—this includes gas engines control systems, power systems such as solar panels and batteries, and remote terminal units to support SCADA communications;
- replacement of end-of-life mechanical equipment—this includes pressure control valves and valves to facilitate in line inspections; and
- preventative works to protect pipeline and MLV assets from corrosion—including fit for purpose transformer rectification units and cathodic protection ground bed systems.

This program extends the design life of the DBNGP by ensuring all ECI and mechanical assets are in good working order.

The pipeline and MLVs have been in operation for more than 40 years. As assets age, they can deteriorate, which increases the likelihood of underperformance. As such, the ongoing levels of planned, preventative and proactive capex activity typically increases over time.

The ongoing program of capex works can be lumpy, particularly as installed ECI, mechanical or cathodic protection assets of a similar age reach end of life at the same time. To smooth the capex profile, our approach is to extend the life of assets where safe and prudent to do so. Where this is not possible, we will replace assets at the end of their technical life.

The program is predominantly a continuation of ongoing works and maintenance techniques based on asset performance, age and inspection data. Corrosion inspection in recent years has identified a significant amount of unexpected corrosion under pipeline and asset insulation. There is also a suite of communication assets that fall due for replacement within the next five years. We therefore anticipate higher levels of pipeline and MLV capex activity during AA6.

9.6.5 Compression reduction project

The scope of this project includes additional looping and removal of a small amount of compression without impacting DBNGP nameplate capacity.

The project will add economic value by:

- reducing compression by mothballing or decommissioning one or more compressor stations to reduce operational and capital costs in a sustainable way;
- reducing or avoiding potential future Safeguard Mechanism costs; and
- reducing DBNGP emissions.

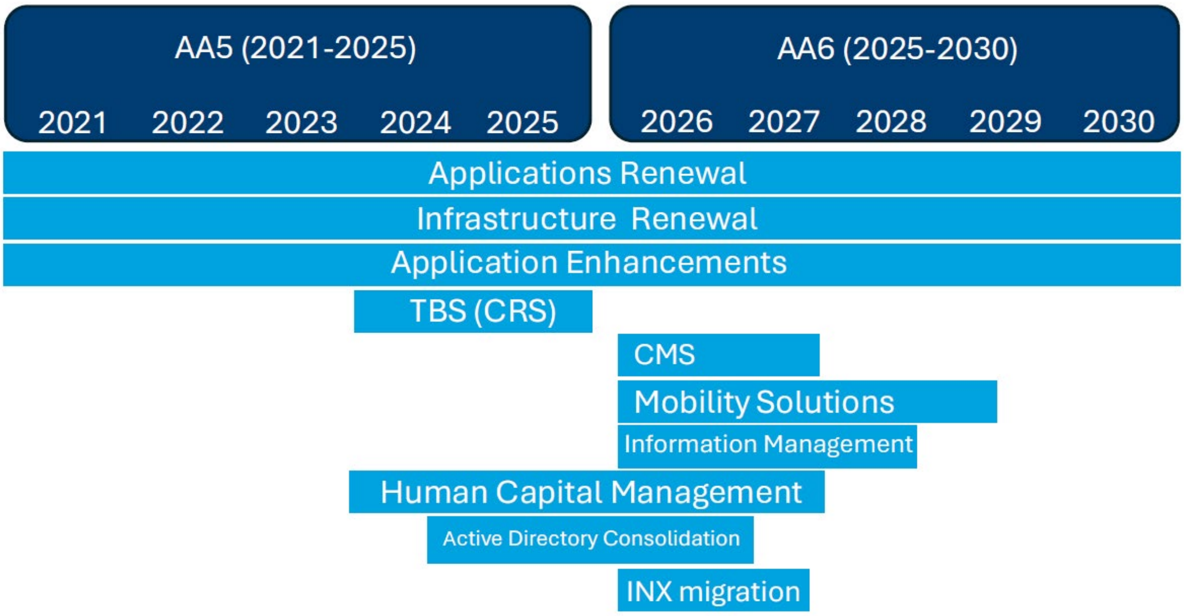
We are currently investigating the merits of the project to ensure it has a positive economic benefit that would sustainably reduce our operational cost base and therefore provide lasting benefits to Shippers.

9.6.6 Information Technology

Our information and technology systems are integral to delivering safe, reliable and efficient services. We have delivered IT infrastructure based on our overarching IT strategy which is to implement a fit-for-purpose digital environment. We discuss what has been achieved in AA5 in Section 9.9.7 and DBP's timeline is shown in Figure 9.3 below.

Our digital strategy and roadmap of initiatives for AA6 are driven by our vision to be sustainably cost efficient. The digital strategy also delivers for customers by securing against threats, modernising systems and increasing digital capabilities. Our strategy also helps us to be a good employer by modernising systems and investing in data management and business intelligence.

Figure 9.3: Timeline of the implementation of DBP's IT program



9.6.7 IT sustaining applications

The IT Sustaining Applications business case encompasses a number of projects which maintain the current levels of IT services and mitigate risks associated with our core business systems through a prudent cycle of system upgrades and replacements.

In AA6, our forecast includes:

- one major and one minor refresh of core business applications including OneERP SAP 4 HANA ($7 million);
- a Contract Management Solution (CMS) to streamline the end to end procurement process and centralise contract administration, efficient tracking, and compliance of contractual agreements ($2 million);
- complete a major Maximo upgrade ($2 million); and
- update our Health Safety and Environment (HSE) software ($1 million).

9.6.8 IT security

The IT Security Applications business case includes expenditure on data security and meeting cyber security obligations. As an operator of critical infrastructure, we take our obligation to operate the DBNGP safely and securely very seriously against the backdrop of cyber threats emanating from the external environment. We are also subject to regulatory obligations as an operator of critical infrastructure, which to an extent drives expenditure in this area.

As a critical infrastructure owner and operator, it is prudent for DBP to ensure cyber controls are commensurate with the organisation's cyber risk. Responding to this regulatory obligation, we are aiming to reach Security Profile level 2 (SP-2) in the current AA period.

The key aspects of the IT security program are:

- cyber resilience;
- technology governance and architecture;
- data protection and privacy; and
- program and change management.

9.6.9 Summary of our AA6 capex by asset category

Figure 9.4 shows our AA6 capex by asset category. As already described above, our expenditure in AA6 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. Table 9.1 below provides a summary of the major business cases for AA6.

Figure 9.4: Total AA6 capex by Asset Category ($million, Dec 2024)

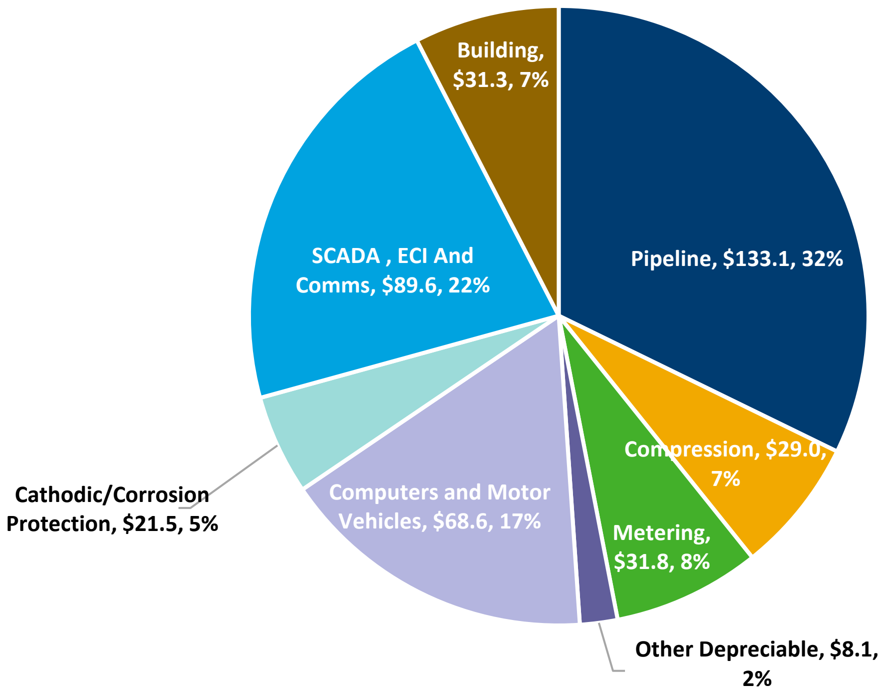


Table 9.1: Summary of major AA6 projects

Business Case	AA5	AA6	Description
Compressor Stations	41.3	48.5	Continuation of existing programs of work including repairs and rectification of compressor station sites to protect from corrosion and safety hazards. Increase driven by hazardous area rectifications, Electrical Protection Integrity Testing (higher cost) and increased security.
Pipeline and MLV	16.4	38.2	Renew end-of-life equipment, repair and undertake preventative works to protect against corrosion, increased CCVT program (19 replacements in AA6 v 5 in AA5), increased inspections, SCADA pack replacements up $5m as now beyond useful life.
Operational Technology (OT)	3.6	15.8	Hardware replacement and software upgrades to SCADA.
Compressor stations accommodation	3.5	12.8	Ongoing renovations/refurbishment of original accommodation facilities at compressor stations.
Compressor Unit Control Systems	17.1	17.9	Replacing obsolete compressor unit control systems which are over 15 years old and no longer supported by the manufacturer.
Jandakot Facility Redevelopment	3.8	17.0	Continuation of the upgrade and redevelopment of the Jandakot site and facilities.
Meter Stations	18.3	33.9	Installation of new gas chromatographs driven by changing gas flow dynamics (KGP, Wheatstone, Mondarra), adding new GCs in order to bill customers accurately, additional recalibration of meters, strategic spares.
IT Security	1.8	5.3	Responding to regulatory obligations to maintain a secure IT environment .
IT Sustaining Applications	27.6	27.5	OneERP major and minor upgrades, Field Mobility, Contract Management System.
IT Sustaining Infrastructure	5.8	15.3	Replacement of IT hardware, replacement of end of life firewalls and switches.
Compression Reduction Project	-	122.6	Targeted upgrade to the DBNGP to reduce the number of compressor stations required on the pipeline, improving its operating efficiency.

9.7 How we will deliver our capex plan 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.

9.7.1 Our Asset Management Plans and Safety Case

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), Work Health and Safety Act 2020, 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, the safe and reliable operations of the DBNGP.

Our AMPs guide the way we invest in our assets and help to ensure that the capex activities we undertake are clearly aligned to our vision. An overarching AMP sets the framework, while specific AMPs outline key risks and controls for each asset type. 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 ensures efficient, reliable and safe operations of the DBNGP are maintained. Similarly, our IT Investment Plan outlines how we invest in IT infrastructure to ensure that we deliver safe, reliable and efficient services to our customers.

9.7.2 Project 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 CAPEX review team where funding requirements, resource availability and optimised delivery of the plan are considered. 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.

The approved capex projects are presented for approval in accordance with our Delegation of Financial Authority, for example to the Board, Executive Leadership Team. Once approved, projects are then managed and monitored in line with our Project Management Methodology (PMM) which we outline below. We regularly report our expenditure performance against prior year spend and approved regulatory allowances.

As the owner of the PMM, the Project Management Office (PMO) 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 outlines the approval process and major project milestones at each stage of the project lifecycle. Our project lifecycle is depicted in Figure 9.5 on the next page.

Any material changes that occur during project execution are strictly managed through the PMM Project Change Request process. This process ensures there is proper governance around changes in scope and cost at all stages of the project lifecycle, including execution.

9.7.3 Procurement

As outlined in Chapter 8, all procurement activities are subject to our Contracts and Procurement Policy. This ensures we carry out these activities in an efficient, cost effective, confidential and ethical manner to:

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

Table 9.2 outlines the minimum information requirements which 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 $500,000 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. 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.

Figure 9.5: Our project lifecycle

Table 9.2: Minimum purchasing requirements

	< $1K	< $20K	$20K - $100K	$100K - $250K	$250K – $500K	$500K+
Via existing Supply Agreements in place	1 written quote (min.) required from available Supply Agreements conducted by the business then validated by C&P			3 written quotes (min.) required from available Supply Agreements conducted by the business then validated by C&P		Tender process min. 4 bidders conducted by C&P
NO existing Supply Agreements in place	Credit card (if-available) for non-inventory items or Purchase Order	1 written Quote (min.) conducted by the business then validated by C&P	3 written quotes (min.) conducted by the business then validated by C&P	3 written quotes (min.) conducted by the business then validated by C&P	3 written quotes (min.) conducted by C&P	

9.8 Our performance in AA5

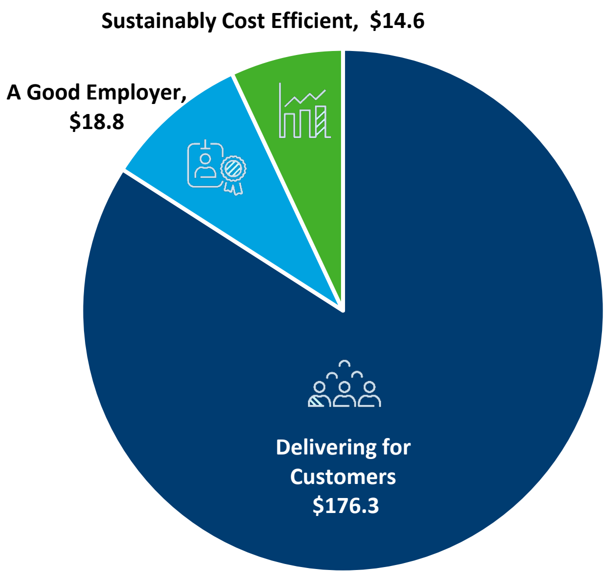
We will have invested $174 million of capex during AA5 up to December 2024 and are forecasting to invest a further $36 million, totalling $210 million by the end of the period. This is $27 million higher than the allowance for AA5 of $183 million, with the delivery of projects impacted by the COVID-19 pandemic and associated delays, supply chain constraints and higher priced inputs.

Our AA5 capex is designed to achieve our objectives of:

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

In AA5, 84% of our capex has been focussed on delivering for our customers (Figure 9.6).

Figure 9.6: Total AA5 capex by driver ($million, Dec 2024)



9.8.1 Delivering for customers

We have invested $147 million to date (forecast $176 million by the end of the period) on various projects and programs that enable us to provide the services our customers require and value. So far in AA5, we have continued to achieve 100% system reliability and zero curtailments.

Key projects which are scheduled to commence in 2025 are the replacement of the obsolete Northern communications system, and the redevelopment of the 40-year-old Jandakot facility.

Other large projects we have completed to ensure ongoing safety and reliability of our pipeline include the rectification of corrosion occurring under compressor insulation, the replacement of end-of-life Fuel Gas trains and Turbine Exhausts and the refurbishment of ageing pipework below the ground.

We are also in the process of delivering a new Transmission Billing System for our customers, replacing obsolete control systems at various Compressor Stations and continuing the dry gas seal and valve replacement programs.

9.8.2 A good employer

We are investing $19 million on projects and programs to support our objective to be a good employer. We are delivering strong safety performance with various initiatives such as the replacement of obsolete isolation valves and fire and gas control system units.

We are also working to ensure good working conditions for our employees by refurbishing compressor station accommodation to cater for a more diverse workforce, refurbishing control room buildings, upgrading other compressor station facility needs and replacing fleet vehicles.

9.8.3 Sustainably cost efficient

We have invested $15 million on projects and programs to ensure we are sustainably cost efficient. We have invested in our IT assets to ensure market currency, compatibility of our services and further cyber resilience through new data centre infrastructure, and various IT hardware and software upgrades.

We are also developing a Decarbonisation Strategy for the DBNGP. Both initiatives represent environmentally and socially responsible responses to a changing operating landscape, and were not forecast in our AA5 approved allowance.

9.9 Key projects and programs we are delivering in AA5

The following sections provide some further detail on some of the key projects and programs we are delivering in AA5. Together, these projects and programs represent 82% of total capex invested in AA5.

9.9.1 Communications infrastructure

In AA5 we are forecast to spend $37 million to deliver independent communications infrastructure for the northern section of the DBNGP. Northern Communications expenditure is in line with the AA5 allowance ($37 million).

The key drivers for this work are delivering for customers in terms of public safety and reliability, and 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.

The project was prudently deferred from the original proposed start date of 2021 as initial quotes for the work came in significantly higher than expected. Our internal governance process precipitated further diligence around scope and re-tendering which ensured that we could implement the most cost-efficient project management plan.

Adopting an in-house delivery approach has resulted in significant savings compared with the alternative contracting option.

The project continues to ramp up, with deferral of $8 million to the next AA period.

We also incurred $1 million in 2021 towards replacement of a portion of the Southern Communications network, which was not in the AA5 allowance because it had been forecast to be completed at the end of AA4.

9.9.2 Compressor stations

In AA5, we are forecast to spend $41 million on compressor stations which is aligned with the allowance ($41 million). The key driver of the compressor stations program has been delivering for customers, particularly in terms of public safety and reliability. Projects have been focused upon:

- the renewal of end-of-life rotating plant (dry gas seal replacement, vibration monitoring and air inlet filters totalling $4 million);
- the upgrade of instrumentation (controls and fire and gas systems totalling $9 million), power supply ($1 million) and other mechanical equipment ($8 million); and
- repair, rectification and preventative works that protect from corrosion ($10 million) and safety hazards ($2 million) or improve performance ($1 million).

Asset corrosion has been more prevalent than expected due to harsh weather conditions along the pipeline, creating the need for additional works not accounted for in the allowance. In particular, we have needed to carry out works to rectify corrosion-related under-insulation of the pipeline ($6 million).

9.9.3 Meter stations

By the end of AA5 we will have invested $18 million in our meter stations. This is higher than the historically low allowance of $10 million due to a number of unforeseen projects in AA5, largely driven by additional asset corrosion and identified under-insulation at meter stations ($1 million), as for compressor stations and other essential ongoing program requirements.

Sites are now being targeted on a priority basis to control costs.

9.9.4 Pipeline and MLV

By the end of AA5 we will have spent $16 million to undertake pipeline and MLV works. This is $6 million above the allowance approved ($11 million) for AA5.

We have needed to replace valves following issues with pig receivers and launcher isolation valves leaking in preparation for our next pigging program in AA6.

We have also needed to replace obsolete CCVTs at a cost of $3 million - higher than approved in the allowance ($1 million). We are implementing a solar battery solution as part of this process at repeater sites, and the program is forecast to continue into AA6. We have also spent $1 million refurbishing failed CCVT anodes and reference electrodes.

9.9.5 Compressor unit control systems

We have implemented a staged replacement approach for compressor unit control systems to ensure obsolete hardware is changed in a timely manner without affecting the safe operation of compressor units.

In AA5 we have replaced eight units (which were planned for in benchmark) at a total cost of $17 million. This is $3 million below the allowance ($20 million). The key driver for this work is delivering for customers in terms of public safety and reliability. The new control system will also allow us to utilise the new control optimisation package to allow for more efficient operation that has been developed by our supplier of compressor units.

Figure 9.7: Compressor Station 10 in Kwinana

9.9.6 Jandakot redevelopment

In AA5, an allowance of $11 million was allocated for the redevelopment of our Jandakot operational facility.

This facility is around 40 years old and needs to be updated. The redevelopment includes providing additional warehouse storage, a redesigned office building which meets current building standards, purpose-built training and meeting facilities, separation of staff and logistics ingress and egress and additional long-term parking for remote staff.

The key drivers for the Jandakot redevelopment are delivering for customers in terms of public safety and reliability, and being a good employer by ensuring a healthy, safe, engaged and skilled workforce. Also, Jandakot is a key communications hub along the DBNGP which is another key driver for its planned upgrade.

The bulk of the delivery of the program has been delayed until 2025 due to multiple planning challenges, and a desire to undertake further employee consultation that was deferred during the COVID-19 pandemic. The program deferral has allowed other high risk pipeline investment projects to be delivered ahead of this project.

We estimate that we will spend $4 million in AA5 on redevelopment works with the remainder of costs ($17 million) deferred until AA6.

9.9.7 Information technology

During the current AA period, we have completed data centre consolidation, rationalisation of our IT managed service providers, our OneERP program and uplift of our cyber security capabilities. These were all key foundations of our AGIG IT launched in 2019.

In AA5 we forecast we will invest $50 million in IT. Our AA5 IT expenditure across our program areas are:

- CRS enhancement ($9 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 ($1 million)— which is an improvement and uplift to the delivery of DBP IT services, enabling effective and efficient services to the customer and ensuring compliance with regulatory obligations;
- IT Sustaining applications ($28 million)— which maintains the current levels of IT services and mitigates risks associated with our core business systems through a prudent cycle of system upgrades and replacements;
- IT Sustaining infrastructure ($6 million)— which ensures existing IT infrastructure continues to support our business systems; and
- IT Security ($2 million)— which ensures all IT services are delivered safely and securely, are resilient to external threats and comply with our security obligations.

Our projected IT capex for AA5 is around $24 million (92%) above our approved allowance of $26 million. The higher than forecast expenditure is due to:

- a change in approach to management of infrastructure (+$2 million);
- investment in collaboration tools to support our business through COVID-19 and ongoing requirements for hybrid working ($1 million);
- the need to replace, rather than upgrade, our Customer Reporting System (+$5 million);
- higher than forecast costs to deliver our OneERP program to replace the obsolete Dynamics AX system with SAP S/4HANA (+$14 million); and
- additional requirements of the Maximo Business Process Redesign and Asset Data Integrity Improvement Program ($2 million).

Though delivery of some IT projects was delayed across the period, by the end of AA5 we will have:

- completed major upgrades to our asset management system, and minor updates to several other critical applications;
- transitioned our IT managed service providers and uplifted our IT operating model;
- completed our OneERP program establishing a functional, fully supported, industry-standard system;
- completed the replacement of our Transmission Billing System; and
- completed many of the foundational initiatives of our AGIG IT Strategy.

9.10 Summary

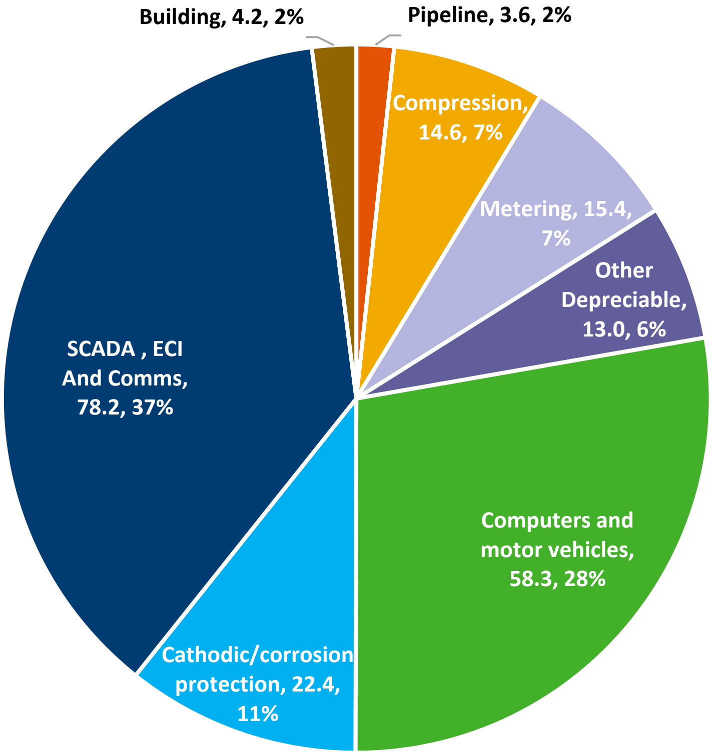
Our expenditure in AA5 has been driven by renewal of compressor station and metering equipment, the replacement of obsolete and end-of-life communications, cathodic protection (including intelligent pigging and in line inspection of the entire DBNGP), the implementation of the OneERP and other ongoing activities to ensure the ongoing safety and reliability of the DBNGP.

Our capex in AA6 will ensure we:

- maintain the strong safety, reliability and service performance we are delivering in AA5;
- have a healthy, engaged and skilled workforce; and
- are sustainably cost efficient into the future.

We will deliver our capex program prudently and efficiently by applying our established project governance and procurement frameworks and reassessing our plans where our business needs change.

Figure 9.8: Total AA5 capex by Asset Category ($million, Dec 2024)



To aid the engagement process, we would welcome your responses to the following questions:

Questions for consideration	
10	**Do you support our approach to forecasting capex? Have we provided sufficient information to understand our proposals and the basis of the costs included?**
11	**Do you think the forecast level of capex in AA5 and AA6 is justified?**
12	**Do you have any other feedback on our capex forecast for AA6?**


ROD

10 Capital base

We estimate that the value of our capital base will decline from around $3.5 billion to $3.0 billion over the next AA period.

IN THIS CHAPTER:

- **Our capital base reflects the value of past investments that we have made in the network, but not yet recovered from our customers**
- **We are reviewing the rate at which we recover our capital base through depreciation as described in Chapter 6, Future of Gas**

We adjust our capital base for capex, depreciation and inflation.

Our adjusted capital base uses actual information over the current AA period and forecast information over the next AA period.

10.0 Regulatory framework

We are required to adjust our capital base to reflect the actual capital expenditure incurred (net of any amounts contributed by our customers), inflation and depreciation to arrive at our closing AA5 capital base.

We are also required to remove the value of any assets that we have sold and reflect the reuse of redundant assets in the current AA period.

Our capital base for AA6 is determined from the closing value of the capital base for AA5 and then adjusted for forecast capex, depreciation and inflation.

Our forecast of depreciation is required to be set:

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

The value of our forecast of regulatory depreciation for AA6 is consistent with that approved in AA5. This includes an amount for accelerated depreciation, which is explained in Chapter 6 (Future of Gas).

Other aspects of determining depreciation have been carried over from AA5, including the outcome of asset recategorisation and the shortening of the economic life of the asset.

10.1 Stakeholder engagement

During Stage 2 of our stakeholder engagement program, we held a number of Shipper Roundtables to engage on key areas of our planning, including our proposed approach to adjusting our capital base.

Specifically, we discussed the uncertainty in the future energy market and the need to consider decarbonisation. We also discussed the need to consider current and future customers and what the right assumptions are to address this uncertainty over the next five years.

We will continue to engage with our customers and stakeholders on this as we refine our plans. Further information on this topic can be found in the Future of Gas (Chapter 6).

10.2 Capital base at 1 January 2026

We have adjusted (or rolled forward) our capital base as at 1 January 2026 for actual capex and inflation, and for forecast depreciation over the remainder of the current AA5 period. Table 10.1 shows the adjustments we have made to our capital base over AA5, however, as it is shown in dollars of December 2024, it does not show the impact of inflation.

10.3 Capital base at 31 December 2030

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

10.3.1 Capital expenditure

Our forecast capex was discussed in Chapter 9 of this Draft Plan and is reproduced in Table 10.2. The asset categories are consistent with those applied in AA5.

10.3.2 Forecast depreciation

The value of our forecast of regulatory depreciation for AA6 is consistent with that approved in AA5—$623 million ($Dec 2024). This includes an amount for accelerated depreciation of $113 million as a placeholder for this Draft Plan whilst the modelling framework and its key inputs are developed. This is explained in Chapter 6 (Future of Gas).

Other aspects for determining depreciation have been carried over from AA5, including the outcome of asset recategorisation and the shortening of the economic life of the asset (Table 10.3).

Table 10.1: Roll forward of the capital base 2021 to 2025 ($m, Dec 2024)

	2021	2022	2023	2024	2025
Capital base @ 1 January	4,050	3,878	3,785	3,698	3,596
Plus Conforming Capex	46	45	54	39	38
Less					
Disposals and redundant assets	-	-	-	-	-
Depreciation	-218	-139	-141	-141	-143
Capital base @ 31 December	**3,878**	**3,785**	**3,698**	**3,596**	**3,491**

Table 10.2: Forecast capex by regulatory asset category in AA6 ($m, Dec 2024)

	2026	2027	2028	2029	2030
Pipeline	2.3	41.1	41.2	47.2	1.2
Compression	6.8	6.3	6.1	4.9	4.9
Metering	9.0	8.6	5.1	4.0	5.1
BEP Lease	2.1	2.0	1.4	1.5	1.0
Computers & Motor Vehicles	23.4	13.0	9.5	14.1	8.5
SCADA/ECI/Comms	4.2	4.5	3.5	3.9	5.4
Cathodic/Corrosion protection	20.6	17.0	20.4	17.5	14.1
Other	6.9	8.7	8.7	3.4	3.6
Total capex	**75.3**	**101.2**	**96.0**	**96.7**	**43.9**

Table 10.3: Proposed asset categories and lives

Proposed AA6 asset categories and lives	Asset life (years)
Pipeline	70
Compression	30
Metering	30
BEP Lease	57
Computers & Motor Vehicles	5
SCADA/ECI/Comms	10
Cathodic/Corrosion protection	15
Other	10

Table 10.4 shows our forecast straight-line depreciation for the AA6 period, which includes the adjusted depreciation.

10.3.3 Inflation

Forecast inflation is a critical element in determining our total revenue and pricing. As explained earlier, forecast inflation is used to adjust the capital base over AA6. This forecast is later updated for actual inflation as AA6 progresses.

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

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

The ERA removes inflation when calculating regulatory depreciation to 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 for an AA period, which is detailed in its Rate of Return Guidelines. This approach uses the difference between

Table 10.4: Forecast straight line depreciation for AA6 ($m, Dec 2024)

	2026	2027	2028	2029	2030
Pipeline	102.8	103.0	106.3	111.4	119.6
Compression	25.2	25.4	25.7	25.9	26.1
Metering	2.3	2.6	2.9	3.1	3.2
BEP Lease	28.7	3.6	3.2	3.1	2.9
Computers & Motor Vehicles	21.7	16.6	16.6	12.7	14.1
SCADA/ECI/Comms	16.1	4.3	4.1	4.1	4.3
Cathodic/Corrosion protection	50.1	11.9	12.8	14.5	15.4
Other	0.0	0.4	0.5	0.7	0.8
Cost of Raising Equity	0.2	0.3	0.3	0.4	0.4
BEP Lease	0.8	0.8	0.8	0.8	0.8
Total straight-line depreciation	**247.9**	**168.8**	**173.2**	**176.7**	**187.7**

Table 10.5: Forecast regulatory depreciation over AA6 ($m, Dec 2024)

	2026	2027	2028	2029	2030
Straight line depreciation	261.1	182.1	191.4	200.0	217.6
Less inflation	87.4	85.2	85.5	85.6	85.5
Regulatory depreciation	**173.7**	**96.9**	**105.9**	**114.4**	**132.1**

Table 10.6: Forecast capital base over AA6 ($million, Dec 2024)

	2026	2027	2028	2029	2030
Capital base at 1 Jan	3,491	3,320	3,255	3,179	3,101
Plus Conforming Capex	77	103	98	98	45
Less					
Disposals and redundant assets	-	-	-	-	-
Depreciation	248	169	173	177	188
Capital base at 31 December	**3,320**	**3,255**	**3,179**	**3,101**	**2,958**

nominal and inflation-indexed Commonwealth Government bonds to derive a forecast of inflation. The forecast is made before the Final Decision.

Applying the ERA's approach to forecast inflation for the Draft Plan provides an estimate of 2.44% per annum over AA6.

10.3.4 Forecast closing capital base

The forecast roll forward of our capital base over AA6, taking into account forecast depreciation, capex and inflation, is set out in Table 10.6. Our capital base declines over the period, from $3,491 million as at 1 January 2026 to $2,958 million as at 31 December 2030.

10.4 Summary

We have adjusted our capital base over AA5 and AA6 to reflect actual and forecast capex, depreciation, including the impacts of accelerating depreciation, and inflation.

The lower value of the asset base to start AA6 will deliver future savings in financing costs for our customers and support the DBNGP to continue to deliver valued services to our customers.

To aid the engagement process, we would welcome your response to the following question:

Question for consideration

13. **Is our approach to adjusting the capital base, including to account for the impacts of accelerated depreciation, appropriate?**

11 Financing costs

We have set our financing costs in line with the ERA's Rate of Return Instrument (RoRI) resulting in a placeholder rate of return of 7.52% and total financing costs of $811 million in AA6.

IN THIS CHAPTER:

- **We have followed the ERA's Rate of Return Instrument**
- **Based on forward market estimates, the placeholder rate of return is 7.52%**
- **Due to government bond rates being significantly higher now than at the start of AA5, financing costs are forecasted to increase significantly from $646 million to $811 million**
- **Tax allowances have changed from $45 million to $116 million**

Financing the $3.5 billion investment in the DBNGP is our largest cost.

Achieving a reasonable rate of return is essential to attract the necessary funding from shareholders and debt providers, and to continue to invest in our pipeline. We also estimate a regulatory tax allowance to cover the cost of tax over AA6.

The following sections outline our approach to calculating financing costs in AA6. All numbers quoted are dollars of December 2024, unless otherwise labelled.

11.1 Regulatory framework

We have applied the ERA's Rate of Return Instrument (RoRI), published in December 2022 and amended in September 2023, to calculate our allowed financing costs. Pipelines and the ERA are required by the NGL and NGR to use the RoRI to determine financing costs.

In addition, we also must estimate the cost of tax using a specified methodology accepted by regulators. This methodology considers our forecast taxable income, the applicable corporate tax rate and the value of imputation credits (gamma) to equity holders.

11.2 Overview

Our financing costs account for 33% of our required revenue. Financing costs represent the cost of financing our capital base and meeting our tax obligations. Our forecast of total financing costs for AA6 is:

- $811 million return on asset; and
- $115 million in cost of tax.

Both have been calculated in accordance with the RoRI.

Note that the return on asset for AA6 ($811 million) is significantly larger than was the case in AA5 ($646 million). Although there are some changes in the ERA's approach in estimating the return on asset from its 2018 Rate of Return Guideline (which was used for AA5) and the 2022 RoRI, the increase is due primarily to changes in government bond rates, which have risen from 0.29% to 4.35%.

11.3 Stakeholder engagement

As outlined in Chapter 5 of this Draft Plan, stakeholder engagement is a key aspect of our approach to developing our plans for 2026–30. We held several Shipper Roundtables to engage on key areas of our planning, including our financing costs.

Our Shippers understand the requirement that we must apply the 2022 RoRI in determining our financing costs, that financing costs are driven primarily by government bond rates at the time the ERA makes its final decision for AA6, and, therefore, that financing costs in this draft plan are indicative only.

11.4 Return on asset

Our return on asset is determined based on an estimate of the return on equity and the return on debt to be incurred over AA6.

11.4.1 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 not possible to observe the return on equity required by shareholders in the market. This means that we are required to use financial models and other market evidence to inform the estimate of the return on equity required by shareholders.

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 ten-year term;
- the market risk premium— which reflects the expected return over the risk-free rate that investors require to invest in a well-diversified portfolio of risky assets; and
- equity beta— which measures the sensitivity of an asset's returns relative to movements in the overall market returns.

In the RoRI, the market risk premium 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. The return on equity is fixed during AA6.

For the purposes of this Draft Plan, we have chosen an estimate based on data for May 2024. The indicative return on equity is 8.62%, shown at Table 11.1.

Table 11.1: Indicative return on equity

Parameters	Value
Equity risk-free rate	4.35%
Beta	0.7
Market Risk Premium	6.1%
Return on equity	**8.62%**

11.4.2 Cost of debt

The cost of debt reflects the interest rate required by debt holders. Much like the return on equity, the cost of debt can be thought to comprise a base interest rate and a risk premium, in this case referred to as the debt risk premium. The approach for estimating the return on debt is prescribed in the RoRI.

The cost of debt is observable in the marketplace and the ERA makes use of market data by summing:

- the five-year swap rate chosen just prior to the Final Decision;
- an allowance for swapping and hedging (fixed at 0.288%); and
- an estimate for 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.

The return on debt is updated annually for the trailing average debt risk premium during AA6.

Based upon data for May 2024, the indicative cost of debt for this Draft Plan is 6.62%, as shown at Table 11.2.

Table 11.2: Indicative cost of debt

Parameters	Value
Debt risk-free rate	4.35%
Debt Risk Premium	1.98%
Debt raising costs	0.165%
Hedging costs	0.123%
Cost of debt	**6.62%**

11.4.3 Rate of return

The ERA assumes gearing of 55%. This means it is assumed 55% of our total financing costs relate to debt, with the remaining 45% relating to equity. Applying these percentages to the return on equity (8.62%) and cost of debt (6.62%) results in an overall rate of return of 7.52% over AA6, as shown in Table 11.3.

Table 11.3: Indicative rate of return

Parameters	Value
Return on equity	8.62%
Cost of debt	6.62%
Gearing	55%
Rate of return	**7.52%**

Table 11.4: Summary of financing cost parameters

Parameters	Value
Return on equity	8.62%
Return on debt	6.62%
Overall rate of return	7.52%
Gamma	0.5

11.5 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.

11.5.1 Calculating the tax allowance

The taxable profit is total revenue (excluding the cost of tax) less opex, tax depreciation and interest expense, where:

- Total revenue— is the sum of all of our costs except the cost of tax (see Chapter 13);
- Opex— is a specific building block that is used to determine total revenue (see Chapter 7);
- Tax depreciation— is based on the calculation of the tax asset base in any particular year
- Interest expense— is determined by multiplying the cost of debt (of 6.62%) by 55% of our capital base in each year, reflecting the debt funded proportion of the total capital base (see Chapter 10).

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 RoRI, gamma is set at 0.5 (Table 11.4). This means our effective tax rate is half of the corporate tax rate.

Table 11.5: Roll forward of the tax asset base ($m, nominal)

	2026	2027	2028	2029	2030
Opening tax asset base	547.8	499.5	490.1	471.8	483.2
Plus Gross Capex	81.3	111.1	108.0	111.2	52.1
Less Tax depreciation	129.6	120.5	126.3	99.8	106.0
Closing tax asset base	**499.5**	**490.1**	**471.8**	**483.2**	**429.3**

Table 11.6: Total tax allowance ($m, December 2024)

	2026	2027	2028	2029	2030
Gross estimated tax cost	61.4	36.7	37.0	47.1	49.4
Less Imputation credits	30.7	18.3	18.5	23.5	24.7
Tax Allowance	**30.7**	**18.3**	**18.5**	**23.5**	**24.7**

11.5.2 Tax depreciation

Tax depreciation is used to determine the estimate of taxable income and to update the value of our Tax Asset Base (TAB). Our approach to determining tax depreciation is consistent with that applied in previous AAs and the ERA's requirements.

11.5.3 Tax asset base

The opening TAB of $548 million as at 1 Jan 2026 has been adjusted for the same forecast of capex used to determine the capital base (see Chapter 9) plus capital contributions received, and a forecast of tax depreciation over AA6 (see Table 11.5).

11.5.4 Tax Allowance

Using the above information, the tax allowance to be recovered in AA6 is summarised in Table 11.6. The gross tax allowance is the corporate tax rate multiplied by taxable profits, and taxable profits are formed as revenues minus operating costs, tax depreciation and interest costs.

11.6 Summary

A summary of our key financing cost parameters, developed in accordance with the RoRI, is provided in Table 11.6.

To aid the engagement process, we would welcome your response to the following question:

Question for consideration

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

12 Incentive scheme

The opex incentive arrangement was introduced for the first time in AA5 to further incentivise efficient opex. Amidst significant cost pressures, we have maintained relative opex efficiency in AA5.

IN THIS CHAPTER:

- **We are forecasting a negative efficiency carryover of $6.2 million as the outcome of the opex efficiency carryover scheme in AA5**
- **We have adjusted our performance against the benchmark on account of a change in our labour cost rate in 2024, which does not reflect opex efficiency performance**
- **We propose continuation of the scheme as the only incentive scheme to apply on the DBNGP in AA6, with the additional exclusion of 'inspections and other asset management' items**

We support the E-factor mechanism as an effective, outcome-based incentive scheme that promotes the long-term interests of our customers.

12.0 Overview

From AA5, an operating cost efficiency incentive mechanism has applied to the operating expenditure we incur for delivery of our transmission pipeline services. The operating cost efficiency incentive mechanism is called the E Factor.

Based on our performance in AA5, we estimate that the E Factor efficiency carryover is negative $6.2 million in AA6. This estimate is likely to be revised further as actual opex estimates for 2024 become available.

We propose that application of the E Factor continues from AA6.

12.1 Regulatory Framework

Under the NGR, an access arrangement may include one or more incentive mechanisms to encourage the efficient provision of services.

Incentive mechanisms provide additional rewards and penalties which can be financial, reputational or administrative (i.e. fast-tracked reviews).

Incentive schemes are often used by regulators to:

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

12.2 Stakeholder engagement

During Stage 2 of our stakeholder engagement program for AA6, we have held Shipper Roundtables to engage on key areas of our plan. This has included the calculation of the E Factor carryover from AA5 and our intention to continue the scheme into AA6.

There was no feedback to suggest that our customers are not broadly comfortable with the current framework to incentivise us to incur only efficient operating costs.

We welcome further feedback on our Draft Plan regarding the calculation of the E Factor carryover and the preference for incentive schemes in AA6.

12.3 How the E-Factor works

Similar to the Gain Sharing Mechanism (GSM), applied by the ERA to Western Power, and the Efficiency Benefit Sharing Scheme (EBSS) applied by the AER, the E Factor provides a continuous incentive to achieve efficiency gains.

The E Factor establishes an annual opex benchmark, which is the sum of all forecast opex that is reasonably within our control and has been calculated using the top-down, roll-forward method.

Any forecast opex that is uncontrollable or that has been forecasted by another method (bottom-up build, for example) is not included in the annual benchmark. This is because opex forecast using a bottom-up build (or similar):

- is typically not predictable enough to prevent windfall gains or losses under an incentive scheme; or
- is built up using forecast demand, including both System Use Gas (SUG) and turbine use, and therefore its inclusion in the scheme would counteract the incentive for demand effects.

Each year, if we are able to outperform the benchmark (spend less than the target), we will then be allowed to retain approximately 30% of the saving (referred to as an efficiency gain), with the other estimated 70% returned to customers via a tariff revenue adjustment in AA6.

To ensure the incentive to outperform the opex benchmark is even in each year of an access arrangement period (and spans between periods), the incremental efficiency gains or losses are carried forward for five years.

The E Factor complements the base year approach we apply to forecasting opex by balancing incentives to make efficiencies in all years of the regulatory period.

The E Factor operating alone might incentivise cost reductions to the detriment of service levels or higher capex. However, there are strict conditions in our Shipper contracts and operating licences that require us to deliver on public safety, reliability and customer service.

12.3.1 Allowed exclusions

The annual E Factor benchmark in AA5 is the total annual operating expenditure forecast approved by the ERA, including any relevant cost pass through event, less the following E Factor exclusions:

1. movement in provisions (such as related to employee provisions);
2. any operating expenditure sub-category not forecast using a top-down, revealed cost approach. These costs:
   i. may include, but are not limited to, operating costs relating to system use gas (SUG), gas engine alternator (GEA) and turbine overhauls and non-recurrent operating expenditure.
   ii. must not include operating expenditure previously classified as capital expenditure that was forecast on a bottom-up basis.
3. any operating expenditure amount not included in the ERA approved operating expenditure forecast, but that meets the requirements of Rule 91(1) and was incurred for the purpose of reducing capital expenditure; and
4. any other operating expenditure amount that the ERA agrees or requires us to exclude from the E Factor benchmark.

Therefore, under clause 15.11(e) of the AA, we have the option to propose to exclude further costs than those already excluded from the opex base from the calculation of the E Factor where we consider that the exclusion of those costs would be consistent with the revenue and pricing principles and the National Gas Objective.

12.4 AA5 opex performance

We are forecasting an efficiency carryover of negative $6.2 million in the next AA period from the operation of this scheme in AA5 (see Table 12.1 below).

Our opex performance in the current period is discussed in more detail in Chapter 8. Our opex forecasting approach relies on actual incurred opex in the penultimate year of an AA period (currently forecast to be $72.7 million, with exclusions (e.g. SUG, GEA/turbine overhauls).

12.4.1 Our proposed AA5 exclusions

Our total opex performance from 2021 to 2024 is estimated to be $440.1 million ($Dec2024). For the purpose of the E Factor, and consistent with exclusion provisions, we have excluded $160.1 million largely driven by $109.5 million in SUG and $34.2 million in overhauls from our AA5 opex performance estimate.

12.4.2 Our proposed AA6 exclusions

In addition to the list of approved exclusions which have applied in AA5, we also recommend that our 'Inspections and other asset management' expenditure be excluded from the calculation of the AA6 E Factor benchmark. Chapter 8 provides more detail on the nature of this expenditure. Similar to GEA/turbine overhauls and SUG, we derive the estimates for this expenditure based on "bottom-up" costing because it is generally lumpy and dependent on factors outside our control of efficiency (such as asset condition, throughput and climatic factors).

12.5 Summary

We are forecasting a negative efficiency carryover of $6.2 million as the outcome of the opex efficiency carryover scheme in AA5.

We propose that the E Factor scheme continues to apply in AA6 as it has in AA5 but that 'Inspections and other asset management' items be excluded from the calculation of the benchmark.

To aid the engagement process, we would welcome your response to the following questions:

Questions for consideration

15. **Do you support our proposed calculation of the Efficiency Carryover Mechanism (ECM) for AA5?**
16. **Do you support our proposed continuation of the ECM in AA6 and the proposed exclusion of 'inspections and asset management' items?**

Table 12.1: Efficiency carryover mechanism

$million (Dec2024)	AA5 period					AA6 period					
Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Opex benchmark (A)	76.9	76.5	76.9	76.9	76.6						
Opex actual (B)	69.2	67.0	71.1	72.7	72.4						
Cumulative saving (C = A - B)	7.7	9.5	5.8	4.2	4.2						
Incremental saving (C_n - C_{n-1})	7.7	1.8	-3.8	-1.6	0.0						
Carryover of incremental gain/loss made in year:											
Year 1		7.7	7.7	7.7	7.7	7.7					
Year 2			1.8	1.8	1.8	1.8	1.8				
Year 3				-3.8	-3.8	-3.8	-3.8	-3.8			
Year 4					-1.6	-1.6	-1.6	-1.6	-1.6		
Year 5						0.0	0.0	0.0	0.0	0.0	
Total Carryover:						4.2	-3.5	-5.3	-1.6	0.0	**-6.2**
Benefits to business (30% based on sum in NPV terms)											
(Cumulative saving + carryover)	7.7	9.5	5.8	4.2	4.2	4.2	-3.5	-5.3	-1.6	0.0	+0 p.a. to year 30
Benefits to customers (70% based on sum in NPV terms)											
(Cumulative saving + carryover 6 years deferred)						0.0	7.7	9.5	5.8	4.2	+4.2 p.a. to year 30

13 Demand

Our demand forecast has two components, contracted capacity and pipeline throughput for reference services. Our forecast for contracted capacity and throughput will be reviewed by an independent expert and reconciled to AEMO's Gas Statement of Opportunities.

IN THIS CHAPTER:

- **Demand for reference services on the DBNGP requires a forecast of both contracted capacity (reserved capacity) and throughput (utilisation of reserved capacity)**
- **We outline how our forecasts will be determined for AA6**

Demand for our services drives our operations and is also a key determinant in calculating reference tariffs.

13.1 Overview

Western Australia's energy sector continues to undergo its transition toward a decarbonised economy with many Shippers currently in the process of making decisions around their decarbonisation pathway.

For this Draft Plan we have adopted a 596 TJ Per Day average Full Haul Equivalent for contracted capacity and 520 TJ Per Day average for Full Haul Equivalent for throughput.

We expect to have additional information to update the adopted assumptions prior to the time of the Final Plan submission to the ERA by 1 January 2025.

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

13.2 Regulatory Framework

Our AA proposal should include a forecast of pipeline capacity and utilisation for reference services over the AA6 period. This is a key input in determining our prices. Our forecast must:

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

13.3 Stakeholder Engagement

We've held several Shipper Roundtables to engage on key areas of our planning, including our proposed demand forecast.

Our Shippers asked for clarification on how actual demand was currently tracking against the AA5 forecast. Views were expressed around the prospect of increasing demand, plans to increase capacity, decarbonisation and the impact this may have on the pipeline.

We clarified that in the early stages of the AA, demand for reference services has been tracking close to forecast, providing good support for the forecasting approach used in AA5.

13.4 How we develop our forecast of contracted capacity

Our AA6 Contracted Capacity forecast is primarily informed by contracts with our Shippers, which are long-term in nature and set out rights to capacity on the pipeline.

There are several high-level factors we consider may influence Shippers' capacity requirements through AA6, such as, but not limited to:

- gas as a transition fuel;
- regulatory and economy wide resource constraints;
- closures of large industrial facilities; and
- opportunities for new facilities.

We are early in the process and intend to update our assumptions for AA6 with the latest changes to contractual positions with our Shippers by the time the Final Plan is submitted so that the best determination can be made for the AA6 period.

13.5 How we develop our forecast of throughput

Throughput is determined by using historical usage information provided by Shippers on their expected plans and expectations for gas use across the AA6 period.

We use average annual throughput levels and historical annual changes in throughput for each of our current Shippers and end-user industry groups. This data is a key input to determining usage rates for each reference service.

We also continue to engage with our Shippers to understand their plans and expected use going forward.

We will also test our forecast against external sources such as the AEMO's Gas Statement of Opportunities.

13.6 Transparency and Verification

Our view of Contracted Capacity will start with executed contracts for reserved capacity during the period. The ERA will have access to these contracts on which it can verify and fact check our assumptions.

Our view of throughput for AA6 will be verified by providing actual throughput during AA5 and testing it against publicly available sources such as the AEMO's Gas Statement of Opportunities, which provides an overall forecast of gas demand in Western Australia.

Whilst the confidentiality of specific details of each Shipper arrangement and usage information will be maintained, aggregated demand information will be shared and presented in public forums. More detailed information will be provided to independent experts and the ERA for detailed review.

We will also have both our forecast of contract capacity and throughput reviewed by an independent expert.

13.7 Summary

We have adopted a forecast average daily contracted capacity in AA6 of 596 TJs on a full haul equivalent basis and throughput of 520 TJ/day on the same basis.

To aid the engagement process, we would welcome your response to the following questions:

Questions for consideration

17. Do you support our proposed approach to forecasting demand?

18. Are there any other factors, including any of your own plans, you think we should consider?

14 Revenue and prices

Our proposed revenues are 40% higher in real terms than current AA5 revenues where the cost of capital was based on historically low interest rates. Pipeline use is relatively stable and so currently does not drive a material change in current reference prices.

IN THIS CHAPTER:

- **Real revenue increase of $712 million (40%) compared to AA5**
- **76% price increase for many customers since AA5 start, 53% increase on current reference service prices**
- **Pipeline use is relatively stable**
- **Key drivers are the return to more 'normal' rate of return conditions and a higher inflationary environment**

Our Draft Plan for AA6 reflects a departure from the AA5 period which was marked by unprecedented financial market intervention and low inflation. Revenues for AA6 reflect a return to historically 'normal' financial market conditions.

This Draft Plan has described the reference services we will provide (Chapter 7) and the cost of providing those services (Chapters 6 and 8 to 12).

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 (or tariffs) that we charge Shippers 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.

14.1 Regulatory framework

We are required to determine total revenue for each year of the next AA period as the sum of our forecast opex (Chapter 8), return on our capital base (Chapter 11), depreciation of the capital base (Chapter 10) and a forecast of the tax allowance (Chapter 11).

Our prices are required to reflect the efficient cost of providing reference services to our Shippers, and this underpins the ERA's assessment of all aspects of our proposal.

14.2 Stakeholder engagement

We held three Shipper Roundtables to engage on key areas of our plan. Shippers indicated price as a topic they wanted to engage on early in the process.

During the first roundtable Shippers requested we share the top three changes to building blocks for the Draft Plan.

At subsequent roundtables we presented a tariff forecast with a break down outlining the impact of each building block, with rate of return being by far the largest driver.

The implications of the increase in risk-free rate from historical lows in AA5 for the tariffs were explained.

Shippers sought confirmation that the bottom-up approach reflected by the building blocks reflect the actual process by which tariff are calculated which we confirmed.

14.3 Revenue

This Draft Plan has set out the derivation of all the relevant building blocks that are used to determine building block total revenue.

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 14.1.

Table 14.1: Building block total revenue 2026-2030 ($m, Dec 2024)

	2026	2027	2028	2029	2030
Return on capital	173.3	164.8	161.5	157.8	153.9
Return of capital (depreciation)	247.9	168.8	173.2	176.7	187.7
Estimated cost of tax	30.7	18.3	18.5	23.5	24.7
Operating costs	119.8	120.7	120.7	123.7	119.1
1% non-reference service allocation	-5.5	-4.5	-4.5	-4.5	-4.6
Total revenue	**472.9**	**500.2**	**501.5**	**498.9**	**498.9**

*Total doesn't necessarily equal cost of service due to revenue smoothing and discounting

14.4 Prices

As already noted, we recover our revenue through the prices that we charge Shippers for providing reference services. This section outlines our proposed 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 blocks total revenue by the forecast capacity demand.

The commodity (or throughput) price is set to cover the variable costs, i.e. System Use Gas (SUG), of delivering reference services and is determined by dividing the variable cost components of our building block total revenue by the forecast capacity demand.

As a result of non-SUG costs increasing at a faster rate than SUG costs, the proportion of fixed and variable costs has shifted in comparison to AA5. To reflect this, we have proposed a ratio of the capacity and commodity components of our reference prices in AA6 of 95:5 (compared to 94:6 in AA5).

In line with stakeholder feedback, we have not proposed any changes to the way our costs are allocated between Full Haul (T1), Part Haul (P1) and Back Haul (B1) prices.

In order to calculate T1, P1 and B1 prices, all demand is converted into T1 'full-haul equivalent' demand. For example, a 10 TJ load halfway down the pipeline would have a full-haul equivalent of 5 TJ. The sum of all full-haul and full-haul equivalent loads is used to determine the T1 tariff, which is then converted to a per kilometre price for P1 and B1 services. This is consistent with the approach adopted by the ERA in previous AAs.

Table 14.2: Draft Plan proposed tariffs

	T1 service ($/GJ)	P1 & B1 services ($/GJ/km)
Capacity reservation charge	2.28	0.0016
Commodity charge	0.13	0.0001
Total tariff	**2.41**	**0.0017**

Our proposed prices for AA5 are shown in Table 14.2.

14.5 Adjustments to Tariff Variation Mechanism

14.5.1 Safeguard Mechanism

We are proposing an additional factor to be included in the reference tariff variation formulae in relation to the Commonwealth's Safeguard Mechanism. It requires facilities in Australia which are responsible for more than 100,000 tonnes of carbon dioxide equivalent per annum to keep their net emissions below an emissions limit (a 'calculated emissions baseline' or simply 'baseline'). Reforms which commenced on 1 July 2023 apply a declining rate to facilities' baselines so that they are reduced predictably and gradually over time on a trajectory consistent with achieving Australia's emission reduction targets of 43% below 2005 levels by 2030 and net zero by 2050.

The DBNGP is a Safeguard facility that is subject to a designated baseline declining over time.

Costs to the DBNGP in complying with the Safeguard Mechanism therefore can be incurred to reduce emissions or to purchase and surrender emissions credits to ensure that net emissions from the network remain within the baseline.

DBP's covered emissions for 2022–23 exceeded the baseline emissions number for the first financial year of the proposed Multi Year Monitoring Plan (MYMP) to 2026–27 that DBNGP had opted to be a part of under the Safeguard Mechanism.

We have committed to a range of activities in the MYMP for the DBNGP to reduce the emissions intensity of the DBP's production variables for natural gas throughput and electricity generation by the end of the monitoring period.

- Pipeline reconfiguration to allow for multi-directional flow of natural gas whilst meeting increased throughput demands, thereby reducing the need for multiple compressors to be running consistently along the pipeline;
- Replacement of seven Gas Engine Alternators (GEAs) with accurately sized and more efficient GEAs at six compressor stations. Note that only one engine will be replaced inside the MYMP timeline; the remainder will be replaced in subsequent years; and
- Replacement of closed-circuit vapour turbines at 19 repeater sites along the pipeline with solar and batteries. Note that six of these turbines will be replaced within the MYMP period. The remainder will be replaced in subsequent years.

These planned decarbonisation activities are reasonably likely to reduce DBP's net emissions number for the MYMP below DBP's facility baseline emission number for the MYMP, to prevent an excess emissions situation which would be unacceptable for the business.

Therefore, we have not proposed any new compliance costs with the Safeguard Mechanism in our AA6 draft proposal for opex.

Instead, we have proposed amendments to the Reference Tariff Variation Mechanism formulae to capture the potential unforeseen costs in our reference prices for the Safeguard Mechanism.

We expect the emissions to be lower than the materiality threshold for cost pass through events, at least in the near term.

14.6 Summary

Our Draft Plan delivers building block total revenue of $2,472 million over AA6, a real increase of $712 million (40%) compared to current AA5 building blocks with return on asset being the key driver.

Our proposed 1 January 2026 reference price of $2.41 is a 76% price increase for many of our customers from the start of AA5, and a 53% increase on current reference prices, also reflecting marked changes in the inflationary environment since 2021.

The capacity and commodity ratio in AA6 is 95:5, compared to 94:6 in AA5, reflecting forecast non-SUG costs increasing at a faster rate than SUG costs.

Our Part and Back Haul prices will continue to reflect a distance factor of the Full Haul price.

To aid the engagement process, we would welcome your response to the following questions:

Questions for consideration
19. Have we provided enough information to understand the basis of our proposed price, including how it is split between the capacity and commodity components?
20. Do you support the proposed cost pass through for the Safeguard Mechanism costs?

15 Pipeline access

We will undertake a review of the terms and conditions of the reference services and propose to update as required.

IN THIS CHAPTER:

- **We will undertake a review of our reference service terms and conditions**
- **This will include consideration of off-specification gas provisions**

Our reference service terms and conditions set the contractual arrangements between DBP and reference service customers and provide a framework for negotiated services.

15.1 Overview

We provide three reference services - Full Haul, Part Haul and Back aul 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.

15.2 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 will be set out in the Proposed Revisions to the Access Arrangement and its Attachments as required by the NGR.[1]

15.3 Stakeholder engagement

We will continue to engage with customers and other stakeholders on our proposed changes to the reference service terms and conditions as part of our stakeholder engagement program.

15.4 Terms and conditions review

15.4.1 Areas of focus

Our review has focused on:

- Off specification gas provisions, so that where the Operator notifies a Shipper that off-specification gas may be delivered at an outlet point, the Shipper is to advise the Operator within an agreed timeframe whether the Shipper elects to reject or accept the delivery of off-specification gas at the outlet point.
- General review of terms and conditions.
- Clarification that terms of existing reference contracts are deemed to be modified to align with applicable terms under a subsequent Access Arrangement approved by the ERA.

15.4.2 Next steps

Following this review, we will propose certain drafting changes to the terms and conditions for each reference service for AA6. An overview of these changes will be available for consultation.

Clean and marked- up versions of proposed T1, P1 and B1 Service terms and conditions will be provided as Attachments to the Access Arrangement Document.

[1] NGR 48(1)(d)(ii)

Alongside our Draft 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 signing of access requests; and;
- clarifying that terms of existing reference contracts are deemed to be modified to align with applicable terms under a subsequent Access Arrangement approved by the ERA.

Other standard updates will relate to our proposals regarding depreciation for establishing the Opening Capital Base, the application of fixed principles, the annual tariff variation mechanism and any other definitional changes or corrections.

15.5 Summary

We are proposing certain amendments to the terms and conditions of the reference services, which will update the reference service contracts, and we invite further feedback from stakeholders on these provisions.

To aid the engagement process, we would welcome your response to the following questions:

Questions for consideration
21. Do you have any feedback on the terms and conditions for our reference services?
22. Are there any specific issues that you would like to see addressed through this terms and conditions review?

16 Stakeholder questions

We have presented stakeholder questions throughout this document on which we are seeking feedback. Your feedback will help us refine our plans, and ultimately put forward a Final Plan that is capable of acceptance by regulators and stakeholders.

What we will deliver	1	Do you have any feedback on our overall plans and performance targets for AA6?
Stakeholder engagement	2	Do you have any feedback on our stakeholder engagement program including our remaining engagement plans for AA6?
Future of Gas	3	Do you agree that we need to consider accelerating depreciation to address future risks?
	4	Is achieving stability in prices through the long term important?
	5	Do you have any other feedback on our accelerated depreciation approach for AA6?
Operating Expenditure	6	Do you support our approach to forecasting opex? Is there sufficient information to understand our proposals and the basis of the costs included?
	7	Do you support our proposed input cost assumptions? If not, why?
	8	Do you think the forecast level of opex is prudent and efficient, particularly given the current cost environment?
	9	Do you have any other feedback on our opex forecast for AA6?
Capital Expenditure	10	Do you support our approach to forecasting capex? Have we provided sufficient information to understand our proposals and the basis of the costs included?
	11	Do you think the forecast level of capex in AA5 and AA6 is justified?
	12	Do you have any other feedback on our capex forecast for AA6?
Capital Base	13	Is our approach to adjusting the capital base, including to account for the impacts of accelerated depreciation, appropriate?
Financing Costs	14	Do you have any comments on our approach to setting the financing and tax costs in this Draft Plan?
Incentive Scheme	15	Do you support our proposed calculation of the Efficiency Carryover Mechanism (ECM) for AA5?
	16	Do you support our proposed continuation of the ECM in AA6 and the proposed exclusion of 'inspections and asset management' items?

Demand	17	Do you support our proposed approach to forecasting demand?
	18	Are there any other factors, including any of your own plans, you think we should consider?
Revenue and Prices	19	Have we provided enough information to understand the basis of our proposed price, including how it is split between the capacity and commodity components?
	20	Do you support the proposed cost pass through for Safeguard Mechanism costs?
Pipeline Access	21	Do you have any feedback on the terms and conditions for our reference services?
	22	Are there any specific issues that you would like to see addressed through this terms and conditions review?
Other	23	Is there anything that our Draft Plan hasn't considered that is important to you?

Feedback

You can provide your feedback on this document by 9 September 2024 via our online engagement portal, Gas Matters.

For more information, or to set up a stakeholder meeting, please contact:

Rachael Tamme
Community Engagement Advisor
D+61 8 8418 1138
E Rachael.tamme@agig.com.au

For **commercial queries,** please contact:

Rachael Smith
Head of Commercial Operations (DBNGP)
D+61 8 8 9223 4318
E Rachael.smith@agig.com.au

For **regulatory queries**, please contact:

Peter Bucki
Head of Regulation
D+61 8 8418 1112
E Peter.bucki@agig.com.au

Our Offices

Australia Gas Infrastructure Group
Level 6, 400 King William Street
Adelaide, SA 5000

Dampier Bunbury Pipeline
12 – 14 The Esplanade
Perth, WA 6000

Australian Gas Infrastructure Group