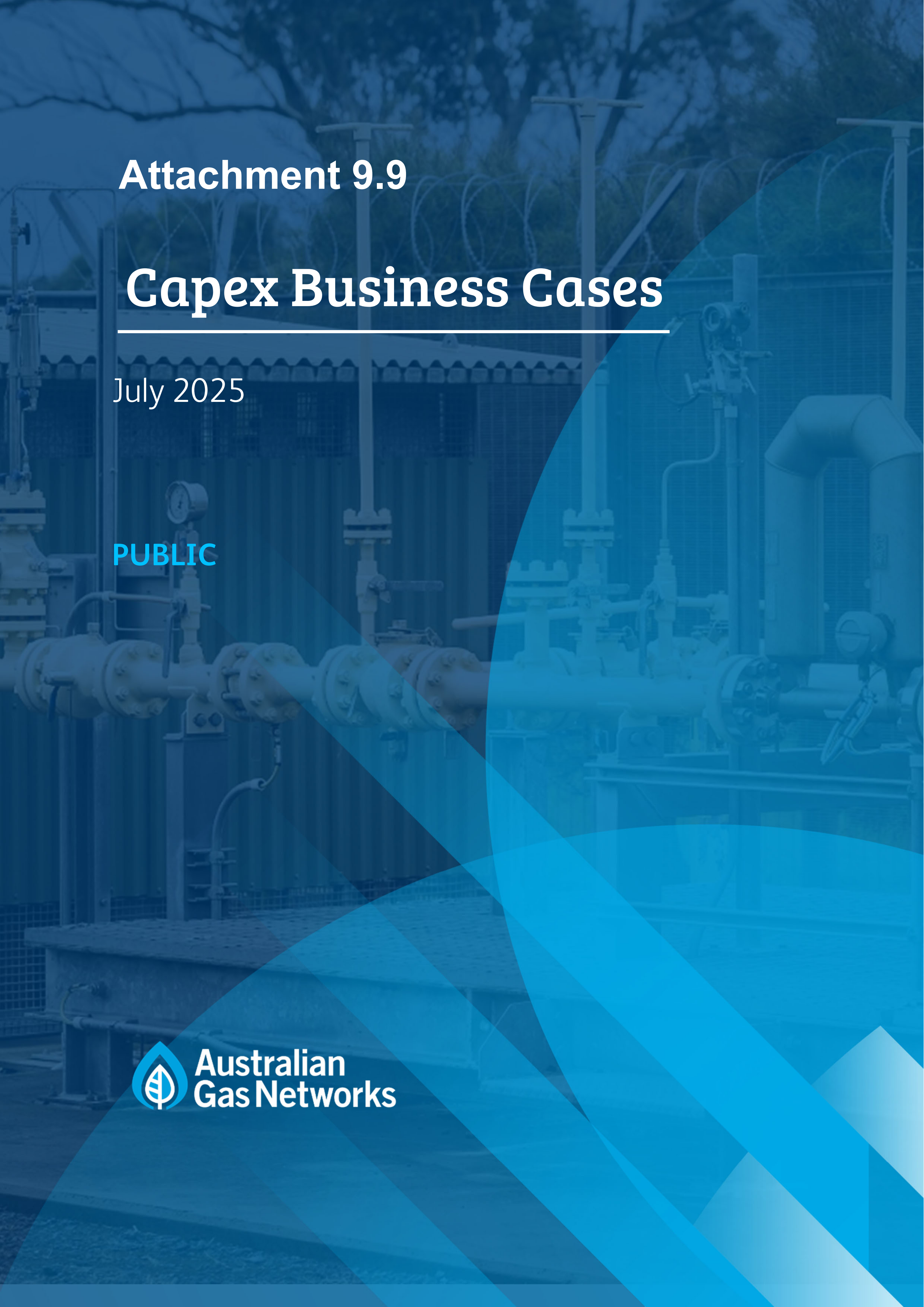

Attachment 9.9

Capex Business Cases

July 2025

PUBLIC

Australian Gas Networks

Contents

SA201 – Corrosion management of steel

1.1 Project approvals

Table 0.1: Business case SA201 – Project approvals

Prepared by	Nick Doblo Project Manager – Access Arrangement Mujib Rahman – Integrity Corrosion Engineer
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Approved by	Michael Iapichello – Head of Engineering and Planning Jason Morony – Head of Networks Operations

1.2 Project overview

Table 0.2: Business case SA201 – Project overview

Description of the problem / opportunity	The South Australia (SA) distribution network includes approximately 200 km of metropolitan transmission pressure (TP) pipelines and 1,600 km of distribution pressure (DP) steel pipelines, which deliver gas to over 485,000 consumers. Most of our TP and DP pipelines are between 40 and 60 years old. Due to their age and material, these mains and their associated services, valves and other steel structures are prone to corrosion. If left untreated, corrosion can lead to integrity failures and uncontrolled gas escapes. The consequences of a major uncontrolled gas escape can be severe, as metropolitan pipelines and their supporting steel structures are typically located in or near developed areas and major population centers. The most cost-effective method to maintain steel integrity and extend asset life is to install corrosion prevention measures such as cathodic protection (CP) and coatings. CP and coatings, while effective, are not infallible and therefore must be monitored and periodically inspected to ensure steel assets are adequately protected from corrosion. We therefore have an ongoing corrosion management inspection and replacement program to help ensure the integrity of steel and ferrous pipeline assets. The proposed works are essentially a continuation of existing corrosion management practices, plus a few new proactive activities to address emerging risks: • Replace and install existing impressed current cathodic protection (ICCP) units and sacrificial anodes that have reached their end of technical life. This includes installing new/additional ICCPs and anodes in parts of the network where the CP system is underperforming • Perform external corrosion direct assessments (ECDAs or 'dig ups') and direct current voltage gradient (DCVG) surveys, and remediate pipelines and heat shrink sleeves where necessary • Inspect and reapply coating on valves, pipework and air-to-soil interfaces • Replace obsolete stray current drainage systems near rail systems • Install CP electrical isolation devices at customer premises to stop stray current impacting the CP system Our approach is to deliver this works over a program optimised over 5 to 10 years to enable efficient delivery.
Untreated risk	As per risk matrix = High
Options considered	• **Option 1** – Deliver CP asset replacement and DCVG/dig ups only, conduct no further proactive corrosion management projects ($6.6 million) • **Option 2** – Deliver all identified CP projects over a 5-to-10-year period ($14.7 million)

- **Option 3** – Deliver all identified CP projects other than those relating to stray currents over a 5-to-10-year period ($11.8 million)

Proposed solution

Option 2 is the proposed solution. This is the optimum balance of achieving risk reduction outcomes and ensuring a deliverable, balanced portfolio of work. Projects that can reasonably be phased over longer timeframe have been extended. These activities will mitigate the high health and safety, operational and compliance risks associated with corrosion of pipelines and will also reduce the operational and financial risks of emergency repairs.

Option 1 would result in escalating risks at key crossing locations in the network, as well as at customer sites and properties.

Option 3, while deliverable and achieving a similar risk outcome, would forego the opportunity to address known issues in an efficient manner (e.g. combining services isolation with our broader services replacement program).

Estimated cost

The forecast direct cost (excluding overhead) during the next period (July 2026 to June 2031) is $14.7 million.

$'000 Jan 2025	26/27	27/28	28/29	29/30	30/31	Total
Corrosion management	2,643	3,306	2,936	2,853	2,959	**14,699**

Basis of costs

All costs in this business case are expressed in real unescalated dollars at January 2025 unless otherwise stated.

Treated risk

As per risk matrix = Moderate

Alignment to our vision

Option 2 would align with the *Customer Focussed* and being *A Leading Employer* aspects of our vision, as maintaining the integrity of our steel pipelines will maintain reliability of supply and mitigate the risk of loss of containment and the associated health and safety consequences.

The proposed solution also reflects *Operational Excellence* as maintenance of CP systems and repair of pipeline coating defects is the lowest sustainable cost of managing the corrosion risk, being significantly less expensive than replacing whole sections of pipeline where the potential for corrosion exists.

This option would also avoid the need for significant unplanned outages associated with full replacement of assets upon failure. These unplanned outages and associated costs would be significant.

This option would reflect *Sustainable Communities* as it is socially responsible and decreases the impact of our organisation on the environment due to the increased risk of a loss of containment event.

Consistency with the National Gas Rules (NGR)

This project complies with the following National Gas Rules (NGR):

NGR 79(1) – The proposed solution is consistent with good industry practice, several practicable options have been considered, and market rates have been tested to achieve the lowest sustainable cost of providing this service.

NGR 79(2) – The proposed capex is justifiable under NGR 79(2)(c)(i) and (ii), as it is necessary to maintain the safety and integrity of services.

NGR 74 – The forecast costs are based on the latest market rate testing and project options consider the asset management requirements as per the Asset Management Strategy. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.

Stakeholder engagement

Our customers have told us their top three priorities are price/affordability, reliability of supply, and maintaining public safety. They acknowledge that corrosion is an inherent risk for steel assets and that an ongoing program to mitigate this risk is necessary.

The proposed corrosion management program is consistent with historical practice and the practices of other gas distribution operators. Stakeholders have raised no concerns with the proposed program for the next period.

Undertaking the proposed corrosion management program will help maintain reliability of supply at the lowest sustainable cost, minimising the impact on

	customers' gas bills. We therefore consider the program is aligned with stakeholder expectations.
Other relevant documents	• Attachment 9.3: Asset Management Plan • Attachment 9.6: Procurement Policy & Procedure • Attachment 9.10: Unit Rates Report • Attachment 9.11: Risk Management Framework • Business case SA205: Pipeline modification for inline inspection • Distribution Mains & Services Integrity Program (DMSIP) • AS/NZS 2885 and 4645

1.3 Background

The SA natural gas distribution networks include 209 km of metropolitan steel transmission pressure (TP) pipelines and 1624 km of steel distribution pressure (DP) pipelines, which deliver gas to over 485,000 customers. The map in Appendix A shows the full TP pipeline network.

The biggest risk associated with steel pipelines is corrosion, which can weaken the pipe wall and cause an integrity failure. Integrity management of steel pipework is a mature asset management field where good practice includes the following:

- Apply a good quality appropriate coating, suitable to the service environment using competent application personnel
- Where pipework is submersed or buried, apply effective cathodic protection.
- Inspect the coating and cathodic protection systems at prudent intervals based on service environment, coating type, historical evidence and accessibility / available inspection techniques
- Take action to remediate defects found during inspections in a timely manner relevant to the scope and severity of the defect

This approach is detailed in a number of relevant standards, particularly, AS 2885.1:2018, which specifies that where corrosion could affect the integrity of the pipeline system, the pipeline system shall have appropriate corrosion mitigation methods implemented. Corrosion mitigation methods on buried pipelines is done using two main methods; pipeline coatings and cathodic protection (CP). The transmission pipeline system must be protected by appropriate CP assets that are still functional and have not exceeded their operational life.

Similarly for the distribution steel mains, AS 4645.2:2018 clause 3.10 specifies that where steel pipe systems are used for gas distribution network protection against corrosion shall as a minimum be achieved by the use of anticorrosion coatings and that a CP system should be designed, documented and implemented.

The majority of steel pipelines in the AGN SA network were constructed prior to 1987, with the two longest and most complex TP pipelines (M42 and M12) being over 55 years old. TP pipelines operate with a maximum allowable operating pressure above 1050 kPa, therefore their design, construction, operation and maintenance are governed by AS/NZS 2885. The steel trunk lines and distribution pipework have similar age profiles but operate at pressure below 1050 kPa and therefore are governed by AS/NZS 4645.

1.3.1 Asset management approach and emerging issues

Our management strategy for TP and DP steel pipeline networks is to replace existing CP systems where those systems are at end of life. We assess the performance of our CP systems via an ongoing inspection and monitoring schedule, which comprises a combination of external corrosion direct assessments (ECDA or 'dig ups') and direct current voltage gradient (DCVG) surveys. Where sacrificial anodes or ICCP systems are at end of life, we replace them. Where we find CP systems are underperforming or insufficient to protect the pipeline, we install additional CP (either anodes or ICCP systems) to ensure no further degradation of the primary assets.

This ongoing process of CP replacement and performance monitoring comprises the bulk of our CP program. However, several further corrosion management issues have been identified that need to be addressed during the next five years:

- **Heat shrink sleeves (HSS)** – Corrosion under HSS has been identified at several locations across our network. Approximately 130 km of pipeline was constructed using HSS. We therefore propose to commence a targeted program of inspection and remediation at HSS locations
- **Coating deterioration** – Higher than expected levels of coating deterioration has been found on valves and assets at soil-to-air interfaces (for example pressure regulating equipment and bridge crossings). We therefore propose to commence a proactive coating inspection and reapplication program, to identify the extent of the issue and develop an ongoing strategy to address it
- **Direct current drainage** – The direct current (DC) drainage systems used to prevent stray current from Adelaide's tram and electrified train network from impacting our steel assets are reaching end of life and are obsolete. We therefore need to replace them with a suitable alternative
- **Service isolation** – Stray current to or from customers' premises can impact our CP system and accelerate steel asset corrosion. It is therefore important to ensure there is no continuous electrical pathway between metallic mains and a customer's installation. We have recently commenced and propose to continue our services isolation program during the next period

Each of these issues and the proposed asset management approach to address them is discussed further in the following sections.

1.3.1.0 Cathodic protection systems for TP and DP pipelines

Cathodic protection is installed on all of our transmission and most distribution steel pipelines. There are two commonly used forms of CP:

- Galvanic sacrificial anodes
- ICCP

Both systems work by using electrical current and transfer of electrons, to make the electrochemical potential of a metal surface (the steel pipe) more electronegative and therefore less susceptible to corrosion. The key difference between an ICCP system and a galvanic sacrificial anode is that an ICCP system uses an external power source with inert anodes, whereas sacrificial anodes use a processed metal that is more electrochemically negative potential (more active) than steel to provide protection.

Galvanic sacrificial anodes are a much simpler system. Sacrificial anodes are installed on the pipe using a welded coupon and are connected to an inspection station (test post) installed near the surface of the ground. Sacrificial anodes require no external power source, as the energy required to inhibit corrosion is generated via anode depletion. However, this means that once the anode is depleted, it offers no protection against corrosion.

Sacrificial anodes are also subject to self-corrosion as the material returns to its natural environmental state even if not actively in use. Sacrificial anodes generally have a maximum effective life of 15 years. Despite this, sacrificial anodes with heavy demands can be consumed to the point of being ineffective in 3-5 years. The simplicity of the sacrificial anode solution means it is particularly cost effective for wide areas containing many electrically disconnected pipes.

An ICCP system has two main components, the ICCP unit (which provides the power source) and the anode bed (which may contain between 2 and 10 anodes depending on current output). The ICCP units include a rectifier that converts the alternating current power source to a direct current that is calibrated to provide the required protection.

An ICCP system typically has a life span of up to 25 years. ICCP units provide the most cost-effective long-term means of CP for larger current demands and can also protect longer length of metallic mains with a single unit, when compared to sacrificial anodes. However, there are limitations on where ICCP units can be installed. For example, ICCP units depend on an external power and need the anode beds to be relatively close to the power supply. Their configuration of higher outputs from a concentrated source also makes them far more prone to causing interference on other electrical structures. This means ICCPs can have limited suitability where the pipeline network configuration is complex, as often occurs in the distribution system. ICCP units therefore tend to be better suited to transmission pipeline configurations.

The longer lifespan of ICCP, combined with the ability to recalibrate power supply to provide additional protection, means our preference is to install ICCP units in favour of sacrificial anodes where practicable. The metropolitan gas distribution network will contain approximately 900 sacrificial anodes and 20 ICCP units at the end of 2025.

For the next five-year period (2026-31), we propose the following program:

- **End of life ICCP and anodes** – We have identified 8 ICCP power and control units and 6 ICCP anode beds that require replacement. Rather than ramp up delivery resources, we propose to deliver these replacements over 10 years. This meaning the ICCP program for the next period will be similar to the current period, replacing four ICCP power and control units, three ICCP anode beds. We will also replace 300 galvanic sacrificial anodes that have all reached their 15-year end of life.
- **Underperforming networks** – Both ICCP and sacrificial anode assets are currently monitored via routine survey and are tested every six months. The surveys have shown that the CP systems associated with our TP pipelines have adequate CP levels. However, we have identified that 122 of the 250 CP systems on the distribution network are no longer able to provide adequate protection levels due to depleted anodes, electrical isolation faults and an increase in the number of coating defects.

  In order to provide adequate protection to these primary assets (inline with industry standard performance which maintains a potential of -0.85 volts (850 mV) to -1.2 volts (1200 mV) relative to the electrode) we will need to:

  - Install 612 new sacrificial anodes at 204 locations
  - Install 1 new ICCP unit to cost effectively boost current output in a single high current demand area

Table 0.3 summarises the proposed ICCP and anode replacement program for the next five years.

Table 0.3: CP asset replacement program 2026-31

CP replacement activity	ICCP systems	Galvanic sacrificial anodes	Estimated cost ($'000)
End of life CP asset replacement	4 power units 3 anode beds	300	2,805
Additional ICCP/anodes required on underperforming CP systems	1 new power unit	612	2,480
Total	**5 power units 3 anode beds**	**912 anodes**	**5,285**

1.3.1.1 DCVG, dig ups, and heat shrink sleeves

1.3.1.1.1 DCVG and dig ups

Our below ground pipelines are coated with a variety of materials. Some older sections are coated with coal tar enamel (CTE), while newer sections are coated with polyethylene (PE) and fusion bonded epoxy (FBE). Heat shrink sleeves (HSS) have been applied to pipelines of various ages. AS 2885 requires the integrity of pipeline protective coatings to be assessed using a DCVG survey where inline inspection is not able to be undertaken.[1]

A DCVG involves taking surface measurements of the amount of electrical current that is escaping through coating faults into the surrounding soil. The coating fault indications are denoted by an IR reading. The IR reading provides an indication of the size of the coating fault. Depending on the size of the IR reading, the location of the pipeline, CP performance and previous dig up history, the section of pipeline where coating indications have been identified will be excavated and directly examined (through ECDA).

Where DCVG results suggest coatings have deteriorated, or where other inspection methods (such as in-line inspection) indicated corrosion may have occurred, we will conduct ECDAs to verify the results. This involves excavating and exposing the affected pipeline, and then performing remedial works where necessary.

DCVG surveys and ECDA only provide an indication of the pipeline coating condition at a sample of locations where the pipeline steel condition has been assessed. Results must be extrapolated for the remaining sections of the pipeline.

Defects with IR readings greater than or equal to 15% have always been prioritised for ECDA and repair. However, due to the age of our network, since 2014 we have also been conducting some ECDA on IR readings <15%.

During the last 5 years we have completed 21 dig ups where IR was <15%. As shown in Figure 0.1, these dig ups on lower level defects have exposed significant issues

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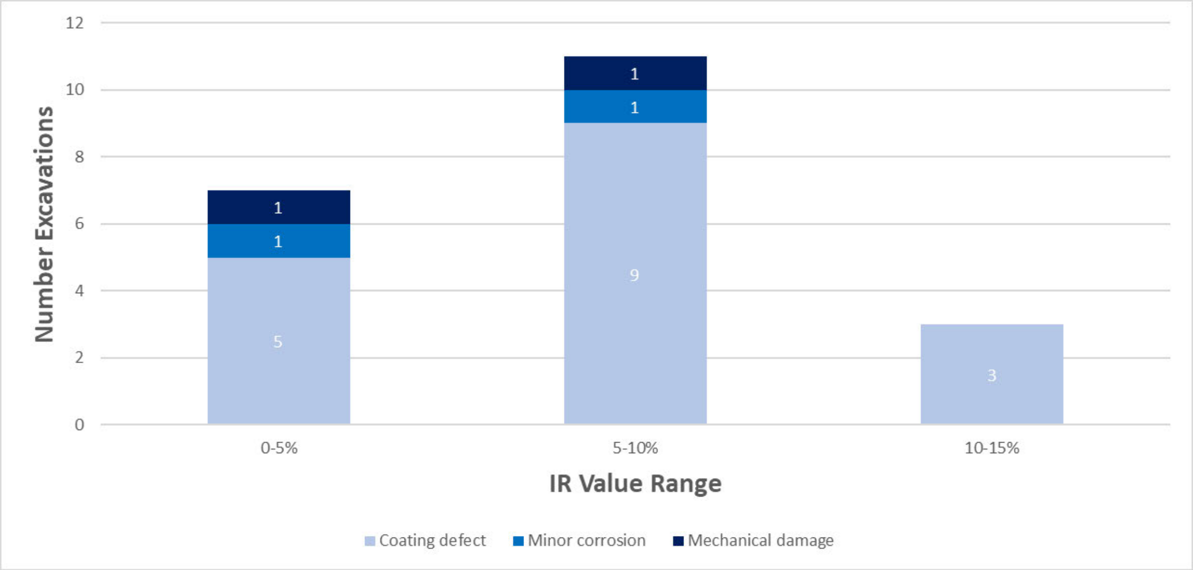
[1] The prevailing industry standard practice approach for detecting corrosion associated with coating disbonding is to use an inline inspection tool (also known as a pigging). However, most TPs in the Adelaide distribution system are currently not piggable.

Figure 0.1: TP pipeline DCVG IR value and ECDA result



The results continue to highlight the value of DCVG and ECDA in detecting mechanical damage to our transmission pipes. For example, excavations on the M5 TP pipeline in Dudley Park uncovered significant damage on the pipeline. We believe the damage was caused by an unreported third party asset strike with an auger (see Figure 0.2).

Figure 0.2: Damage on M5 TP pipeline detected by DCVG survey and excavation

The results of DCVG surveys completed in 2001 and 2012 both indicated IR readings less than 15% at this location. The excavation revealed minor corrosion on the pipeline, however it also identified gouges on the pipe resulting in reduced integrity.

The damaged sections of the pipeline were temporarily repaired by the installation of Plidco bolted sleeves and then permanently repaired using welded steel fittings in the current period. If these defects were not detected and repaired, over time this could have resulted in a leak requiring isolation and emergency repair. Consequences of this, at minimum, would have included a high risk to the security of supply of around 100,000 customers and a repair cost in excess of $250,000.

As per AS 2885, surveys of the whole 200 km of TP pipelines are performed every five years. Based on the latest DCVG surveys there are a further 16 locations identified for ECDA that will be completed in the current period.

Over the next five years, we expect DCVG surveys will continue to identify locations for inspection and forecast our dig up program to be aligned with ongoing volumes of 25 digs every five years for TP pipelines.

In addition to the 25 TP digs, a further 7 digs are planned for DP trunk mains. With the degraded CP performance of large areas of the distribution network it is prudent to complete DCVG surveys and investigate similar indications in the distribution steel pipework. The 7 digs are based on 1 dig per 20 km of steel trunk mains.

Table 0.4: Dig up program 2026-31

Pipeline pressure	Forecast number of digs	Estimated cost, $’000
Transmission pressure	25	1,052
Distribution pressure	7	295
Total number of digs	**32**	**1,347**

1.3.1.1.2 Heat shrink sleeves (HSSs)

Corrosion under HSS is an emerging issue. HSSs are a method for coating the field joints between pipe segments where the factory applied coating to the pipe was not applied or was removed for welding purposes. HSSs were common practice in the pipeline construction industry during the 1970s and 1980s when much of the TP backbone of the SA network was installed. This means approximately 130 km of TP pipeline system was built using HSSs.

Unfortunately, HSSs have proven not as effective or easy to achieve a quality application as initially designed. Where a poor bond is achieved between the sleeve and the steel pipe, or where that bond has degraded, moisture wicks up into the HSS and can cause general or pitting corrosion. CP is not effective against this corrosion as the outer electrical barrier of the HSS is still intact, meaning CP currents are unable to penetrate more than about five times the depth of crevice opening.

The lack of CP penetration into a disbonded HSS also limits the ability of DCVG surveys to detect these corrosion occurrences though it is sometimes effective if there is sufficient disbondment at the edge of the HSS. Industry practice is to use ILI to demonstrate pipeline integrity. ILI is effective at detecting the wall loss from corrosion under HSS, and depending on the specific tool used, can detect disbondment of the HSS before corrosion has reduced pipe wall thickness.

At the time of construction of most of Adelaide’s Transmission Network, ILI was not standard practice, and as such reconfiguration is required (where practicable) to allow TP pipelines to be pigged. While ILI reconfiguration works is underway (see business case SA205), it will be several years before the majority of our network is piggable.

In the absence of ILI, the current methodology for addressing HSS is to start with a DCVG and ECDA. Where that pipeline has known HSSs, we extend the dig in each direction from the DCVG indication to the field weld. Once exposed, we strip the HSS, blast and inspect the steel condition under the HSS, mechanically repair if required, and then recoat with a modern coating system. Where evidence of corrosion under an HSS is present, particularly advanced corrosion, the excavation will then move one pipe length in either direction, pothole to confirm location of the field weld(s) and complete another pair of remediation actions as required.

The results of previous HSS surveys on TP pipelines in the Adelaide network indicate a systemic problem with corrosion under disbonded HSS. This problem was most evident on the M21 and M53 pipelines, where it was deemed more cost effective to lay new pipe than dig and remediate every HSS along the pipeline.

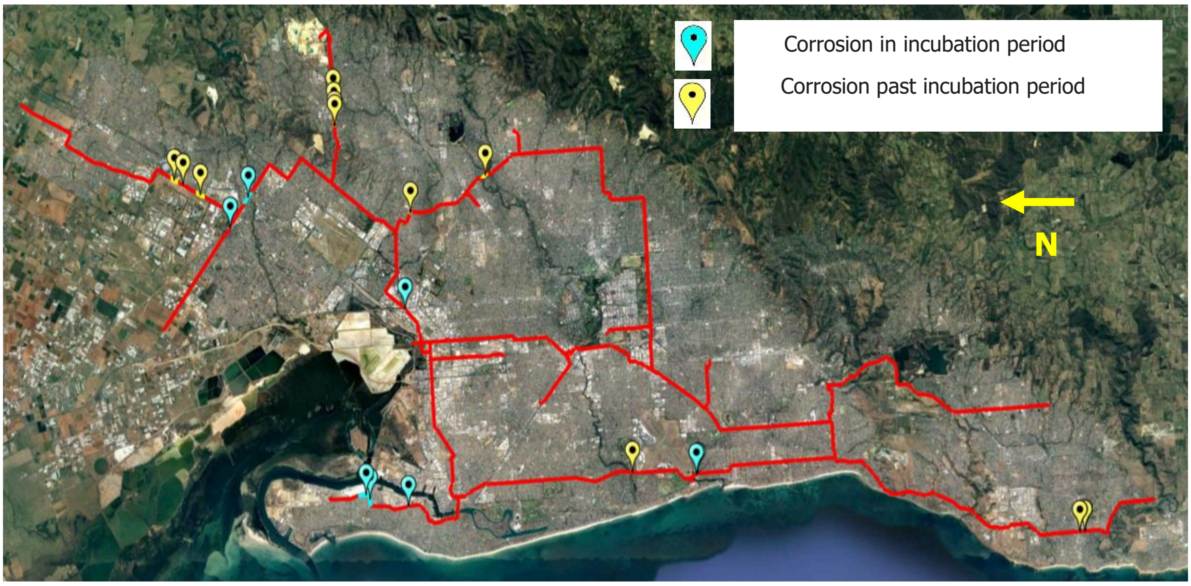
In general, corrosion was mostly found to be in the form of tunnelling pit corrosion, with varying depths of up to 2.4 mm (i.e. up to 38% of the pipe wall thickness), when measured using a manual pit gauge. An example of the excavation findings are shown in the images below.

Figure 0.3: Photos taken from HSS excavation sites of M21 and M53 pipelines, showing deep tunnelling pits (a and b) scattered (c and d) over pipe surface.

Figure 0.4: Excavations on M55 at Hogarth Rd, Elizabeth South

Further review of other ECDA records determined that while these M21 and M53 pipelines were the worst affected, they were not the only pipelines affected (see Figure 0.5).

Figure 0.5: HSS excavations on TP pipelines in South Australia



In the current period, with the completion of the M21 and M53 replacements, the HSS program was paused to determine whether there were better methods for locating disbonded HSSs or field joints/welds prior to excavation to minimise dig length and cost. However, ILI conversion and inspection remains the only other technically viable solution. We therefore propose to continue with the current HSS dig up, inspection and remediation program. Pipelines identified for ILI conversion have been excluded from the scope of works outlined in this business case, however, these pipelines must be included should ILI conversion not occur.

The HSS program will need to find and remediate 130 field joints with HSSs over a ten-year period. This is based on an average of one HSS dig up per 1 km of TP pipeline constructed with HSS, which is ~1% of the forecast total number of HSSs on the network. We believe this will provide sufficient information and data to make informed decisions for asset strategies over the longer term. This means we propose to dig up and remediate 65 HSSs over the next five years.

Table 0.5: HSS program 2026-31

Volume	Estimated cost, $’000
65	2,736

1.3.1.2 Inspect and reapply coating on valves, pipework and air-to-soil interfaces

The South Australian network has large number of steel and ferrous assets that rely solely on protective coatings for corrosion protection. These range from steel valves and associated pipework to air-to-soil interfaces at locations such as regulating equipment and bridges.

In the last few years we have identified several corrosion related issues on assets, particularly on valves and air-to-soil interfaces, where coating has deteriorated more quickly than anticipated. These issues to date have been identified on an ad-hoc reactive basis, where corrosion is discovered while doing associated works in the area.

By way of example, [redacted] [redacted] [redacted] between two isolation valves. The junction developed a leak due to corrosion, with the bubbles on the pipework showing the location. This is the single source of supply to the suburb of North Haven. Rectification in this case required bypasses, cutting out of the entire section, temporary bypasses installed on a new alignment, reinstallation of new pipework and reinstatement.

Figure 0.8 shows a degraded 150 mm DP main under a bridge exposed to salt spray in Henley Beach that would have been identified sooner had there been a proactive air-to-soil interface inspection and remediation project. This main is currently out of service while a rectification solution is developed.

Figure 0.7 shows the condition of air-to-soil interfaces when they are not identified early, where their overall integrity is compromised such that replacement is required. These particular assets had to be replaced. Early intervention would have allowed a more cost-effective recoating solution.

Figure 0.7: Examples of poor condition air to soil interfaces

Figure 0.6: Corrosion in DP valve pit, North Haven

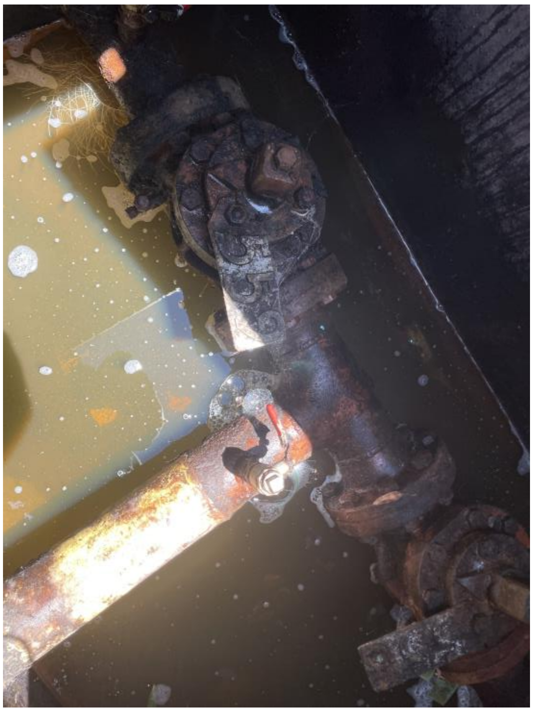


Figure 0.8: Corrosion under bridge, Henley Beach

The frequency of coating issues identified on steel valves and air-to-soil interfaces suggests there may be a systemic issue. We therefore propose to implement a proactive coating inspection and remediation program across these types of steel assets.

There are more than 2,800 steel valves on mains larger than 40mm in diameter and 560 air-to-soil interfaces across our network. Rather than attempt to remediate them all straight away, our approach is to inspect and remediate approximately 5% of these types of assets over the next five years. We consider this will provide a sufficient sample to identify the scale of the problem and inform the asset management strategy moving forward.

Table 0.6 summarises the proposed program.

Table 0.6: Proposed steel coating remediation project volumes and cost

Asset type	Network total	Volume to be inspected/recoated	Estimated cost, $'000 /site
Steel valves and associated pipework	2,841	100*	1,913
Air-to-soil interfaces	564	28	535
Total installations	**3,405**	**128**	**2,449**

* A further 40 valves (9TP and 31DP) will be addressed through the emergency isolation valves program, see business case SA203.

The prioritisation of the program of works is guided by reported condition and operating pressure, therefore TP equipment will typically be addressed first due to their increased consequence of risks should assets fail. The goal is to identify trends and recoat corroding assets prior to replacement in order to avoid costly replacement programs.

1.3.1.3 DC traction current drainage

DC traction drainage systems are designed to manage and mitigate the effects of stray currents from DC electrified rail systems such as those used by the Adelaide trams and electrified trains. Stray currents can cause significant and rapid corrosion, and damage nearby metallic structures such as pipelines leading to integrity issues, and if gone untreated result in a loss of containment.

The Adelaide distribution network currently has four drainage systems, which are passive devices designed around germanium diodes. Germanium diodes are a semiconductor that uses germanium as their primary material and were amongst the first semiconductor diodes. These diodes have been almost entirely replaced by the far more common silicone diodes in modern electronics.

The germanium diode is important in passive DC traction drainage systems due to their much lower forward voltages of 0.3 volts vs the 0.7 volts of silicone diodes. This enables the germanium diodes to be used to provide a return path between the rail and the steel pipeline experiencing DC traction pickup, without interfering with the CP system on the pipeline. The germanium diodes are now obsolete, with spares unable to be sourced. An equivalent diode is also unable to be sourced.

As such, these four systems need to be replaced with actively powered systems called transformer rectifier assisted drainage (TRAD) systems. These systems are similar to an ICCP system, however they act between the pipe and the rail.

TRADs are more technically involved to install due to the need for power and commissioning of setpoints, but provide additional benefits in actively managing pipe potential relative to the rail. TRADs are the industry standard traction drainage system and are now commonly used in other distribution networks.

Over the next five years we propose to replace the four existing germanium diode-based drainage systems with TRADs. Given the extremely high rate of corrosion that can occur with unmitigated DC traction it is not prudent to replace these systems upon failure, particularly given the significant changes required to implement a powered system.

Table 0.7: Proposed TRADs and costs

Number	Estimated cost, $’000
4	505

1.3.1.4 Service isolation safety program

AGN has an ongoing program of works to ensure there is no continuous electrical pathway between metallic mains and a customer’s installation. Having electric separation of our TP and DP networks from consumer installations is important for the following reasons:

- **Preventing galvanic corrosion downstream of the meter**: Without isolation, our CP systems could cause galvanic corrosion on the customer's equipment, leading to premature failure and safety hazards

- **Maintaining CP effectiveness of AGN systems**: Isolation ensures that the CP system works efficiently on the distribution main without interference from the customer's electrical system
- **Safety**: It prevents electrical faults and potential safety hazards that could arise from unintended electrical connections between the systems

There are two viable solutions to address the risks and thereby ensure electrical separation:

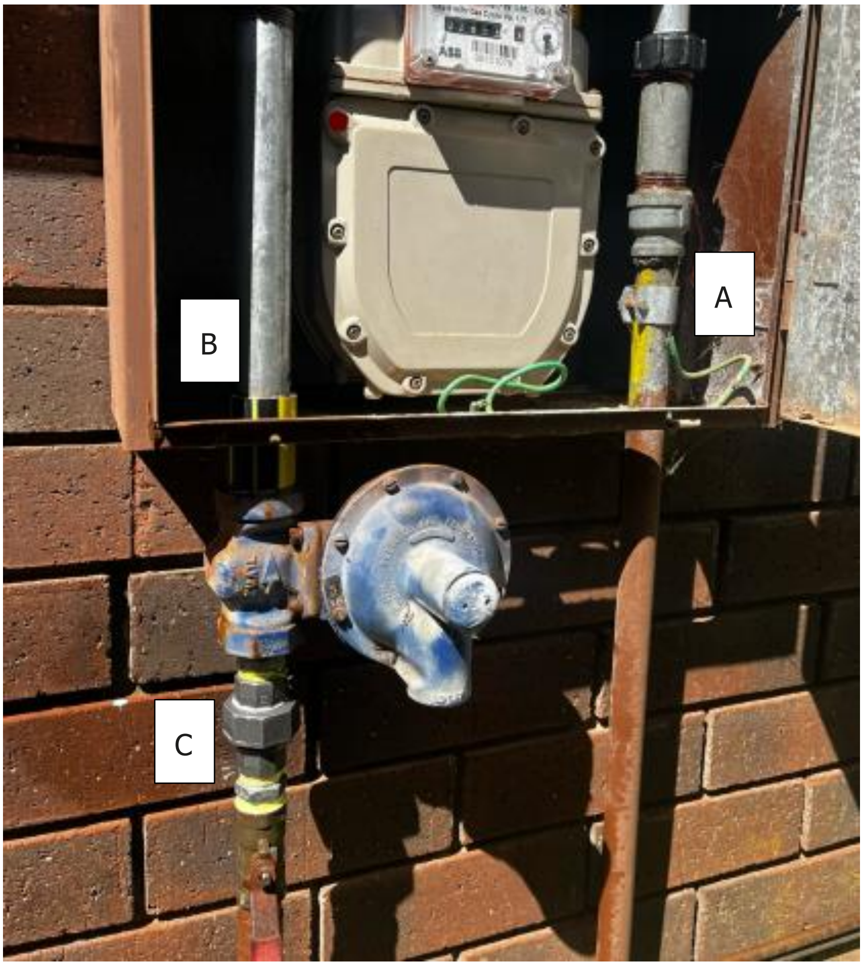
1. The preferred option is to install an electrical isolation fitting between electrically earthed customer meter and the CP protected metallic distribution main and service (see Figure 1.9).
2. Where the preferred option cannot be achieved the metallic service is replaced with a fully fused PE solution.

Figure 1.9: Metallic service post isolation fitting installation

A – Electrical Earth on customer side

B – Insulating collar used in first attempt to rectify isolation without service modification

C – Isolating barrel union installed on modified (shortened) service



Historically, these service isolations have been completed as and when they are discovered by our operational teams. Our aim is to cease this ad-hoc approach and instead factor service isolation into our proactive services program. This is particularly relevant for the next period, as multi-user services and services replacement is a focus of our DMSIP.

Table 0.8: Service isolation program, 2026-31

Number	Estimated cost, $'000
1125	2,376

1.4 Risk assessment

Risk management is a constant cycle of identification, analysis, treatment, monitoring, reporting and then back to identification. When considering risk and determining the appropriate mitigation activities, we seek to balance the risk outcome with our delivery capabilities and cost implications. Consistent with stakeholder expectations, safety and reliability of supply are our highest priorities.

Our risk assessment approach focuses on understanding the potential severity of failure events associated with each asset and the likelihood that the event will occur. Based on these two key inputs, the risk assessment and derived risk rating then guides the actions required to reduce or manage the risk to an acceptable level.

Figure 0.10: Risk management principles

Our risk management framework is based on:

- AS/NZS ISO 31000 Risk Management – Principles and Guidelines
- AS 2885 Pipelines-Gas and Liquid Petroleum
- AS/NZS 4645 Gas Distribution Network Management

The Gas Act 1997 and Gas Regulations 2012, through their incorporation of AS/NZS 4645 and the Work Health and Safety Act 2012, place a regulatory obligation and requirement on us to reduce risks rated high or extreme to low or negligible as soon as possible (immediately if extreme). If it is not possible to reduce the risk to low or negligible, then we must reduce the risk to as low as reasonably practicable (ALARP).

When assessing risk for the purpose of investment decisions, rather than analysing all conceivable risks associated with an asset, we look at a credible, primary risk event to test the level of investment required. Where that credible risk event has an overall risk rating of moderate or higher, we will undertake investment to reduce the risk.

Seven consequence categories are considered for each type of risk:

1. **Health & safety** – injuries or illness of a temporary or permanent nature, or death, to employees and contractors or members of the public
2. **Environment** (including heritage) – impact on the surroundings in which the asset operates, including natural, built and Aboriginal cultural heritage, soil, water, vegetation, fauna, air and their interrelationships
3. **Operational capability** – disruption in the daily operations and/or the provision of services/supply, impacting customers
4. **People** – impact on engagement, capability or size of our workforce

5. **Compliance** – the impact from non-compliance with operating licences, legal, regulatory, contractual obligations, debt financing covenants or reporting / disclosure requirements
6. **Reputation & customer** – impact on stakeholders' opinion of AGN, including personnel, customers, investors, security holders, regulators and the community
7. **Financial** – financial impact on AGN, measured on a cumulative basis

The primary risk event being assessed is that undetected or unaddressed corrosion leads to widespread degradation of steel TP or DP trunk infrastructure, resulting in significant uncontrolled loss of containment and costly asset replacement.

The untreated risk[2] rating is presented in Table 0.9.

Table 0.9: Risk rating – Untreated risk

Untreated risk	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minimal	Major	Minor	Significant	Significant	Catastrophic	
Risk Level	High	Negligible	High	Low	Moderate	Moderate	High	

Depending on the time and location it occurs, a loss of containment on one of these critical assets can adversely affect supply to tens of thousands of customers or at least one major demand customers using >10TJ per year. Additionally, in the event an emergency repair is required, a pipeline section may need to be isolated, which can also affect supply to a significant number of customers.

In certain circumstances, an uncontrolled gas escape at one of these locations can have major health and safety consequences, leading to fatality or life-threatening injuries. Any major failure would also result in costly asset replacement, likely greater than $50 million.

As a result, the untreated risk associated with corrosion at these TP pipeline locations is rated high.

Untreated, this risk also poses a moderate compliance risk, against obligations to maintain integrity of the pipework under AS 2885 and 4645.

1.5 Options considered

The following options have been identified to address the risk of corrosion causing substantial loss of containment on the network:

- **Option 1** – Deliver CP asset replacement and DCVG/dig ups only. Conduct no further proactive corrosion management projects
- **Option 2** – Deliver all proposed CP projects over a 5 to 10-year period
- **Option 3** – Deliver all CP projects other than those relating to stray currents over a 5 to 10 year period

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[2] Untreated risk is the risk level assuming there are no risk controls currently in place. Also known as the 'absolute risk'.

A further option of ceasing all CP programs was considered. However, this would significantly accelerate corrosion, meaning that full steel network replacement would be brought forward, at a replacement value of approximately $3 billion ($1,500/metre). Even though replacement would result in the lowest overall risk, this option was discredited prior to full evaluation due to extreme public risks that would occur for mains that would corrode before being replaced, as well as the cost impact on customers for an accelerated replacement program.

1.5.1 Option 1 – Deliver CP asset replacement and DCVG/dig ups only

Under this option we would only conduct the sacrificial anode and ICCP replacement programs, along with compliance-related DCVG activities. This would essentially be a reactive-only program.

We would replace end of life anodes/ICCP and install additional CP assets in underperforming parts of the network. We would conduct DCVG and ECDA, but we would not proactively dig up and remediate HSS.

The proposed proactive coating, DC drainage and service isolation program would not be conducted. Instead, these assets would only be replaced/recoated/installed when the affected assets have failed or when issues are identified on an ad-hoc basis.

1.5.1.1 Advantages and disadvantages

The advantage of this program is the lower up front capital cost. Forecast CP expenditure would be reduced to what is effectively a subsistence level, driven by ongoing CP asset replacement and addressing issues as and when they arrive. Depending on the level of asset failure and the type of assets that fail, this option has the potential to be the lowest short term cost while still maintaining compliance requirements and minimum service levels.

However, the disadvantages of this option are significant. By not proactively addressing known and emerging corrosion risks such as HSS and coating deterioration, we are running the risk that these issues escalate beyond current controls. Proactive action would allow us to get on top of the issue before it becomes material and results in severe consequences. Avoiding proactive measures increases the likelihood that corrosion remains undetected and results in a major risk event.

The long term cost of this option is likely to be high. Should extensive corrosion continue unchecked, it will inevitably result in widespread leaks. This would result in a program of extensive and high volume repairs and potential TP and DP pipeline replacements. There would also be significant cost of leak repair on TP and DP pipelines (TP is approximately $200,000 per repair) as well as switching costs involving re-lights and temporary gas connection through emergency bottles or trailers for the affected customers.

1.5.1.2 Cost assessment

The estimated direct capital cost of this option is $6.6 million. This estimate is based on current material and labour rates.

Table 0.10: Volumes and cost estimate – Option 1, $'000 January 2025

Option 1	2026/27	2027/28	2028/29	2029/30	2030/31	Total	Cost ($'000)
CP							
End of life replacement							
ICCP units	0	0	2	2	0	4	206
ICCP anode bed	0	0	1	1	1	3	189
Sacrificial anodes	60	60	60	60	60	300	2,410
Underperforming pipelines							
ICCP systems	0	1	0	0	0	1	283
Sacrificial anodes	41	41	41	41	40	204	2,197
External corrosion direct assessment							
TP DCVG ECDA	5	5	5	5	5	25	1,052
DP DCVG ECDA	0	3	3	1	1	7	295
TP HSS ECDA	-	-	-	-	-	-	
Valves and air-to-soil interfaces	-	-	-	-	-	-	
DC drainage							
DC drainage replacement	-	-	-	-	-	-	-
Service safety program							
Service modification	-	-	-	-	-	-	-
Service replacement	-	-	-	-	-	-	-
Total cost ($'000)							**6,632**

1.5.1.3 Risk assessment

While Option 1 offers at least some measure of risk treatment, we consider it would do little to reduce the risk any lower than the untreated risk rating. Although the risk associated with failed CP anodes/ICCP systems would be addressed, the emerging risks associated with HSSs, failed coatings, stray currents and service isolation would not be mitigated. The issues caused by HSSs and coating deterioration and service isolation in particular are likely to result in corrosion, which will remain unchecked until failures occur, by which time it is too late.

We therefore consider Option 1 does not reduce the likelihood of the primary risk event occurring any lower than 'unlikely' and therefore the overall risk rating remains high.

Table 0.11: Risk rating – Option 1

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minimal	Major	Minor	Significant	Significant	Catastrophic	
Risk Level	High	Negligible	High	Low	Moderate	Moderate	High	

Failing to address a high risk rating where there is a practicable treatment available is not consistent with the requirements of our risk management framework, and does not reflect the actions of a prudent asset manager.

1.5.1.4 Alignment with vision objectives

Table 0.12 shows how Option 1 aligns with our vision objectives.

Table 0.12: Alignment with vision – Option 1

Vision objective	Alignment
Customer Focussed – Public Safety	N
Customer Focussed – Customer Experience	-
Customer Focussed – Cost Efficient	-
A Leading Employer – Health and Safety	N
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	-
Operational Excellence – Benchmark Performance	N
Operational Excellence – Reliability	N
Sustainable Communities – Enabling Net Zero	N
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	N

Option 1 would not align with our objectives of *Customer Focussed*, as it would not address the safety risks associated with coating defects and corrosion on steel pipelines or steel assets. Allowing assets to fail and potentially giving rise to safety incidents would also place our employees in harm's way and would also not be consistent with the actions of a socially responsible organisation. This is inconsistent with our objective of being *A Leading Employer*.

It is also likely that the long-term costs of a reactive asset replacement would be considerably greater than a proactive refurbishment (or proactive replacement) program. The reliability impact of the potential need for the replacement of assets upon failure would be significant. This option therefore does not align with our objective to be *Operational Excellence*.

This option would not reflect *Sustainable Communities* as it would not be socially responsible, and increases the impact of our organisation on the environment due to the increased risk of a loss of containment event.

1.5.2 Option 2 – Deliver all proposed CP projects over a 5-to-10-year period

Under this option, we would continue current practices: CP asset replacement, additional CP in underperforming networks, and DCVG and ECDA. However, these would be complemented by the additional proactive programs outlined in section 1.3.1.

We would proactively address the HSS and coating issues, while also replacing the DC drainage systems and managing the risks associated with stray currents from customers' premises.

Rather than imposing an artificial five-year timeframe for each project, we have assessed the entire portfolio to determine the optimum balance of the available resources and the risk reduction achieved.

The scope of works is outlined below and in Table 0.13:

- Proactive replacement of 50% of ICCP units exceeding their technical life (4 anode beds, 3 CP units) in the next 5 years, with the remainder to be completed within the following 3 years
- Proactive replacement of 300 sacrificial anode at the end of their technical life
- Installation of one ICCP system and 612 sacrificial anodes at 204 locations to address the underperforming steel distribution networks
- Continuation of DCVG and ECDA volumes based on the last 15 years and in line with compliance requirements
- Remediation of HSSs based on one excavation per km of affected pipeline over a 10-year period to achieve ~1% of total HSS population, with 65 inspections to be conducted over the next five years
- Remediation of 5% of the valves and air-to-soil assets over the next five years such that enough information is available to determine long term asset management strategies
- Proactive replacement of 4 obsolete DC drainage systems
- Completion of the service safety program over the next seven years

1.5.2.1 Advantages and disadvantages

The advantage of this option is that it will enable us to address the corrosion risk within a reasonable timeframe at an efficient cost. Proactive management of the HSS, coating and stray current issues will allow us to get ahead of the issue before it becomes a more urgent and ultimately expensive problem. This approach should help reduce long term costs by avoiding the high operational costs involved with emergency repairs (approximately $200,000 per repair), as well as avoiding potential switching costs in the event of asset failure ($50-$100 per affected customer).

The HSS and recoating programs are designed to cover a sample size large enough to allow us to understand the extent of the issue, which means we can develop cost effective asset management strategies moving forward and avoid the likelihood of a large scale, bulk replacement program.

The services isolation program is scheduled for the next five years, as multiuser services (and services more broadly) are a focus of our DMSIP. It makes sense to take the opportunity to ensure our customers are electrically isolated from metallic mains while our crews are onsite.

The disadvantage of Option 2 is the forecast cost for the period. Of the three options considered, Option 2 has the highest work volumes and is therefore the highest short term cost.

1.5.2.2 Cost assessment

The estimated direct capital cost of this option is $14.7 million. This estimate is based on current material and labour rates.

Table 0.13: Volumes and cost estimate – Option 2, $’000 January 2025

Option 2	2026/27	2027/28	2028/29	2029/30	2030/31	Total	Cost ($’000)
CP							
End of life replacement							
ICCP units	0	0	2	2	0	4	205
ICCP anode beds	0	0	1	1	1	3	189
Sacrificial anodes	60	60	60	60	60	300	2,409
Underperforming pipelines							
ICCP system	0	1	0	0	0	1	283
Sacrificial anodes	41	41	41	41	40	204	2,197
External corrosion direct assessment							
TP DCVG ECDA	5	5	5	5	5	25	1,052
DP DCVG ECDA	0	3	3	1	0	7	295
TP HSS ECDA	13	13	13	13	13	65	2,736
Valves and air to soil interfaces	25	25	26	26	26	128	2,449
DC drainage							
DC drainage replacement	0	2	0	0	2	4	505
Service safety program							
Service modification	173	173	173	173	173	865	661
Service replacement	52	52	52	52	52	260	1,714
Total cost ($’000)							**14,699**

Tables may not sum due to rounding

1.5.2.3 Risk assessment

Option 2 reduces the risk from high to moderate, which we consider is as low as reasonably practicable (ALARP). While the proposed program will reduce the likelihood of the primary risk event occurring from unlikely (possible in certain circumstances) to remote (may occur if abnormal circumstances prevail), the potential consequences of an asset failure would remain major due to the inherent risk associated with loss of containment and the potential for large numbers of customers being off supply.

Table 0.14: Risk rating – Option 2

Option 2	Health & Safety	Environment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Moderate (ALARP)
Consequence	Major	Minimal	Major	Minor	Significant	Minor	Significant	
Risk Level	Moderate	Negligible	Moderate	Negligible	Low	Negligible	Low	

Reducing the overall risk to moderate is ALARP. Option 2 prudently defers projects where possible such that the cost impact is over a longer period, therefore lessening the impact on regulated revenue (and therefore regulated tariffs within a single access arrangement period).

1.5.2.4 Alignment with vision objectives

Table 0.15 shows how Option 2 aligns with our vision objectives.

Table 0.15: Alignment with vision – Option 2

Vision objective	Alignment
Customer Focussed – Public Safety	Y
Customer Focussed – Customer Experience	Y
Customer Focussed – Cost Efficient	-
A Leading Employer – Health and Safety	Y
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	-
Operational Excellence – Benchmark Performance	Y
Operational Excellence – Reliability	Y
Sustainable Communities – Enabling Net Zero	Y
Sustainable Communities – Environmentally Focussed	Y
Sustainable Communities – Socially Responsible	Y

Option 2 would align with the *Customer Focussed* and being *A Leading Employer* aspects of our vision, as maintaining the integrity of our steel pipelines will maintain reliability of supply and mitigate the risk of loss of containment and the associated health and safety consequences.

The proposed solution also reflects *Operational Excellence* as maintenance of CP systems and repair of pipeline coating defects is the lowest sustainable cost of managing the corrosion risk, being significantly less expensive than replacing whole sections of pipeline. Where we are addressing emerging risks we are presenting a balanced profile of works to better understand the optimum asset management strategy in the future. This ensures we can deliver the program within industry benchmarks.

This option would avoid the potential need for the significant unplanned outages associated with full replacement of assets upon failure. These outages and associated costs would be significant.

This option would reflect *Sustainable Communities* as it is socially responsible and decreases the impact of our organisation on the environment due to the increased risk of a loss of containment event.

1.5.3 Option 3 – Deliver all CP projects other than those relating to stray currents

Under this option, we would deliver the program as per Option 2, however:

- We would not replace the DC drainage system or proactively deliver the service isolation safety program. We would continue to rely on the existing DC drainage system, postponing its replacement to a future period
- We would only address the issue of stray currents to customer premises reactively

1.5.3.1 Advantages and disadvantages

The advantage of this option is the lower cost (when compared to Option 2). The scaled back program would also require fewer resources, which could be deployed on other projects. Option 3 would also avoid the disruption caused when we have to excavate in Adelaide city centre to replace the DC drainage system.

The disadvantage of this option is that we would be foregoing the opportunity to address known issues that lead to steel corrosion.

With regard to the DC drainage replacement, though the current systems are operational they are obsolete and at the end of the technical life. This means that if system performance declines significantly, it will be difficult to get spare parts and keep the system operational. Replacing the DC drainage system is currently a relatively low cost ($0.5 million), however, given the recent rising costs of traffic management and materials, the cost of replacing the system is only likely to increase sharply the longer we leave it. The system is already at the end of its life and stray currents are a potential problem, therefore it makes sense to the replace the DC drainage with a suitable alternative sooner rather than later.

If we maintain our current practice of only isolating services when stray currents are detected, not only are we allowing avoidable corrosion to occur, but we are also foregoing the opportunity to achieve compliance and reduce corrosion. We are also missing the opportunity to bundle the isolation works with our broader services replacement program.

1.5.3.2 Cost assessment

The estimated direct capital cost of this option is $11.4 million. This estimate is based on current material and labour rates.

Table 0.16: Cost estimate – Option 3, $’000 January 2024

Option 3	2026/27	2027/28	2028/29	2029/30	2030/31	Total	Cost ($’000)
CP							
End of life replacement							
ICCP units	0	0	2	2	0	4	206
ICCP anode beds	0	0	1	1	1	3	189
Sacrificial anodes	60	60	60	60	60	300	2,409
Underperforming pipelines							
ICCP system	0	1	0	0	0	1	283
Sacrificial anodes	41	41	41	41	40	204	2,197
External corrosion direct assessment							
TP DCVG ECDA	5	5	5	5	5	25	1,052
DP DCVG ECDA	0	3	3	1	1	7	295
TP HSS ECDA	13	13	13	13	13	65	2,736
Valves and air-to-soil interfaces	25	25	26	26	26	128	2,449
DC drainage							
DC drainage replacement	-	-	-	-	-	-	-
Service safety program							
Service modification	-	-	-	-	-	-	-

Service replacement	-	-	-	-	-	-	-
Total cost ($'000)							**11,817**

1.5.3.3 Risk assessment

When assessed under the risk matrix, Option 3 achieves a similar level of risk reduction to Option 2. This is because Option 3 still addresses the majority of the biggest causes of corrosion: CP end of life, HSS and recoating. However, the overall risk reduction in reality would be less than Option 2, as the potential for corrosion caused by stray currents is not being addressed proactively. The risk matrix does not have sufficient granularity to make this distinction. It could therefore be argued that while the overall risk is reduced from high to moderate, the moderate rating under Option 3 is not ALARP.

Table 0.17: Risk rating – Option 3

Option 3	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Moderate (not ALARP)
Consequence	Major	Minimal	Major	Minor	Significant	Minor	Major	
Risk Level	Moderate	Negligible	Moderate	Negligible	Low	Negligible	Moderate	

1.5.3.4 Alignment with vision objectives

Table 0.18 shows how Option 3 aligns with our vision objectives.

Table 0.18: Alignment with vision – Option 3

Vision objective	Alignment
Customer Focussed – Public Safety	N
Customer Focussed – Customer Experience	N
Customer Focussed – Cost Efficient	Y
A Leading Employer – Health and Safety	Y
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	-
Operational Excellence – Benchmark Performance	Y
Operational Excellence – Reliability	Y
Sustainable Communities – Enabling Net Zero	-
Sustainable Communities – Environmentally Focussed	Y
Sustainable Communities – Socially Responsible	N

Option 3 would align with most of our vision objectives as per Option 2. However, it could be argued that this option is not *Customer Focussed* or *Socially Responsible* given we would not be addressing the potential issues associated with customer premises not being electrically isolated from metalling mains.

1.6 Summary of options assessment

Table 0.19 presents a summary of how each option compares in terms of the estimated cost, the residual risk rating, and alignment with our objectives

Table 0.19: Comparison of options

Option	Estimated cost	Treated residual risk rating	Alignment with vision objectives
Option 1	$6.6 million	High	Does not align with *Customer Focussed, A Leading Employer,* or *Operational Excellence*
Option 2	$14.7 million	Moderate (ALARP)	Aligns with *Customer Focussed, A Leading Employer,* and *Operational Excellence*
Option 3	$11.8 million	Moderate (not ALARP)	Aligns with *Customer Focussed, and A Leading Employer. Could be argued that it is not* and *Operational Excellence*

1.7 Proposed solution

Option 2 is the proposed solution. We propose to undertake the full CP program over 5-10 years, as outlined in section 1.3.1.

1.7.1 Why is the recommended option prudent?

Option 2 is the most prudent option because:

- The proactive repair of coating and corrosion defects on TP and DP pipelines will reduce the need for emergency repairs that have the potential to result in supply constraints and excessive repair and switching costs
- It is the option that provides best balance between risk reduction, investigating emerging risks in a balanced manner, and is considerate of a tight labour market and controls cost
    - Option 1 does not mitigate the high health and safety, operational and compliance risks associated with corrosion of the TP and DP pipelines nor other steel assets
    - Option 3 does not address known corrosion issues in a proactive manner, and foregoes the opportunity to rectify issues associated with stray currents
- Option 2 is consistent with customer and stakeholder expectations and our vision that we will maintain current high levels of safety and reliability

1.7.2 Estimating the efficient costs

The project costs have been developed using established programs of work and where new programs are being developed, we have benchmarked similar established programs. A summary is provided in Table 1.20.

Table 1.20: Basis of costs

Option 3	Program	comments
CP		
End of life replacement		
ICCP units	Historical costs	Well established ongoing program. Materials quote updated in 2024
ICCP anode beds	Historical costs	Well established ongoing program

Option 3	Program	comments
		Materials quote updated in 2024
Sacrificial anodes	Historical costs	Well established ongoing program Materials quote updated in 2024
Underperforming pipelines		
ICCP system	Historical costs	Well established ongoing program Materials quote updated in 2024
Sacrificial anodes	Historical costs	Well established ongoing program Materials quote updated in 2024
External corrosion direct assessment		
TP DCVG ECDA	Historical costs	Well established ongoing program
DP DCVG ECDA	Historical costs	Well established ongoing program
TP HSS ECDA	New Project	Based on efficient extension of DCVG excavations
Valves and air to soil interfaces	New Project	Bottom-up build based on forecast units and known re-coating costs
CP drainage		
DC drainage replacement	New Project	Bottom-up build based on typical excavation costs at similar locations. Materials based on TRAD vendor estimates
Service safety program		
Service modification	Historical costs	Established program started in AA5. Routine meter change used for benchmarking
Service replacement	Historical costs	Established program started in AA5. AMRP Service Renewal used for benchmarking

1.7.3 Consistency with the National Gas Rules

In developing these forecasts, we have had regard to NGR 79 and 74. As a prudent asset manager, we give careful consideration to whether capex is conforming from a number of perspectives before committing to capital investment.

NGR 79(1)

The proposed solution is prudent, efficient, consistent with accepted and good industry practice and will achieve the lowest sustainable cost of delivering pipeline services:

- **Prudent** – The expenditure is necessary to ensure that the ongoing integrity of the TP and DP pipelines and steel assets is maintained and to reduce the risk of major gas escapes that could impact public safety and reliability of supply, and is of a nature that a prudent service provider would incur.
- **Efficient –** CP through ICCP, galvanic sacrificial anodes and effective coatings is the most efficient way to extend the life of the primary steel assets they protect. The remediation work is the most practical and effective option. It is also the most cost effective option. Engineering assessments and design will be carried out by internal staff and field work will be carried out by external contractors based on competitively tendered rates. For those assets with emerging risks, a reasonably scaled project has been developed such that

informed asset management strategies can be developed in future. The expenditure is therefore of a nature that a prudent service provider acting efficiently would incur.

- **Consistent with accepted and good industry practice** – The ongoing effective management of the integrity of the TP and DP pipelines and other steel assets is consistent with AS 2885.3 and AS 4645. Reducing the risks posed by the corrosion of these assets to ALARP and in a manner that balances costs and risks is also consistent with this standard.
- To achieve **the lowest sustainable cost of delivering pipeline services** – The remediation works are necessary to maintain the long term integrity of the TP and DP pipelines and other steel assets. Failure to do so would result in additional expenditure (reactive response to a major gas escape and bringing forward replacement) and shorten the life of the pipelines. The project is therefore consistent with the objective of achieving the lowest sustainable cost of delivering services.

NGR 79(2)

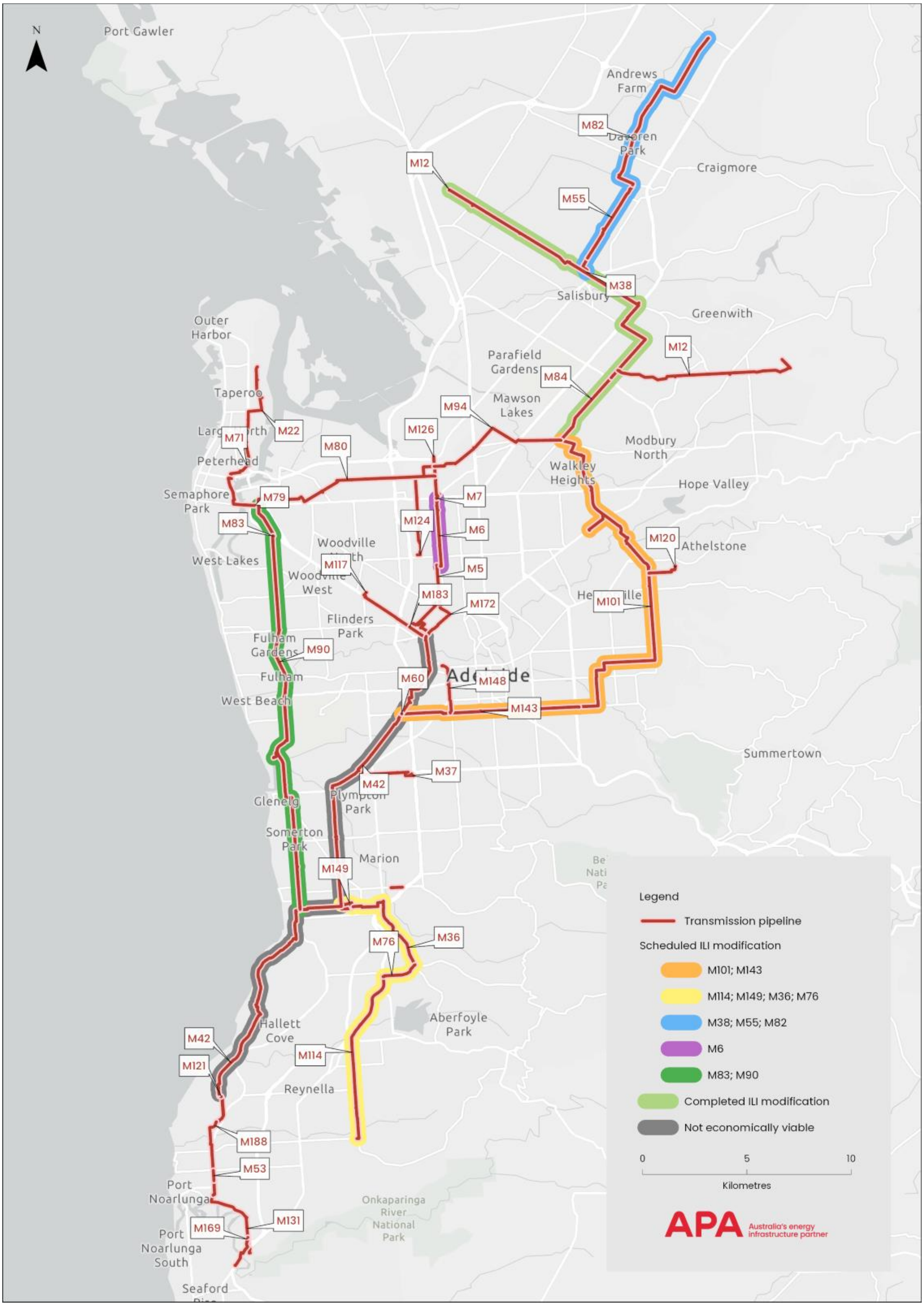
The proposed capex is justifiable under NGR 79(2)(c)(i) and 79(2)(c)(ii), as it is necessary to maintain the safety and integrity of services. Allowing TP and DP pipelines to continue to corrode to the extent performance is compromised will lead to network integrity issues, disruption to customer supply and potential uncontrolled release of gas. Option 2 achieves the risk reduction required over a reasonable timeframe that is considerate of reducing the risk of cost escalation through resource constraints. We therefore consider Option 2 better meets the requirements of NGR 79(2).

The current practice has proven successful in uncovering coating defects and corrosion and remediation of these issues will allow us to maintain a level of service consistent with customer and stakeholder expectations.

NGR 74

The forecast costs are based on the latest market rate testing and project options consider asset management requirements. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.

Appendix A SA metropolitan TP pipeline network



Appendix B Comparison of risk assessments for each option

Untreated risk	**Health & Safety**	**Environ-ment**	**Operations**	**People**	**Compliance**	**Rep & Customer**	**Finance**	**Risk**
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minimal	Major	Minor	Significant	Significant	Catastrophic	
Risk Level	High	Negligible	High	Low	Moderate	Moderate	High	

Option 1	**Health & Safety**	**Environ-ment**	**Operations**	**People**	**Compliance**	**Rep & Customer**	**Finance**	**Risk**
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minimal	Major	Minor	Significant	Significant	Catastrophic	
Risk Level	High	Negligible	High	Low	Moderate	Moderate	High	

Option 2	**Health & Safety**	**Environ-ment**	**Operations**	**People**	**Compliance**	**Rep & Customer**	**Finance**	**Risk**
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Moderate (ALARP)
Consequence	Major	Minimal	Major	Minor	Significant	Minor	Significant	
Risk Level	Moderate	Negligible	Moderate	Negligible	Low	Negligible	Low	

Option 3	**Health & Safety**	**Environ-ment**	**Operations**	**People**	**Compliance**	**Rep & Customer**	**Finance**	**Risk**
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Moderate (not ALARP)
Consequence	Major	Minimal	Major	Minor	Significant	Minor	Major	
Risk Level	Moderate	Negligible	Moderate	Negligible	Low	Negligible	Moderate	

SA202 – Non-compliant domestic meter sets

1.1 Project approvals

Table 0.1: Business case SA202 – Project approvals

Prepared by	Matthew Haynes – AA Project Engineer Andrew Saliba – Manager System Operations
Reviewed by	Robin Gray – Manager Operations SA
Approved by	Jason Morony – Head of Networks Operations

1.2 Project overview

Table 0.2: Business case SA202 – Project overview

Description of the problem / opportunity	The AGN SA distribution network has over 485,000 meters in operation on the network. Approximately 600 of the domestic meters (0.12% of the total population) are currently identified as installed in non-compliant locations due to legacy issues, private renovation work or updated compliance standards. These meters are not scheduled for rectification under any existing or proposed mains or services program. These non-compliant domestic meter sets have been identified within the metropolitan area as well as regional networks in Port Pirie, Whyalla and Mt Gambier. The solution is to move the meter to a compliant location where ignition or gas accumulation is not a threat, and then re-installing or modifying the service line from the main in the street as required. Relocations of these meters occur reactively as they are identified during periodic meter changes or general maintenance work. They are discovered and rectified at a rate of approximately 60 per year in the metropolitan area. The metropolitan rolling database has an inventory of approximately 100 non-compliant meters. For regional areas we have undertaken camera inspection work on mains in Port Pirie that has determined that there are 111 non-compliant domestic meters in the Port Pirie network. Surveys of the Mount Gambier and Whyalla networks have identified 103 and 275 non-compliant meter sets respectively. This gives an estimated total inventory of ~600 known non-compliant domestic meter sets identified to date within the network. The current inventory of non-compliant meters is summarised in the table below. **Location** / **Estimated volume**: Adelaide Metropolitan area 100; Port Pirie 111; Mt Gambier 103; Whyalla 275; **Total** **589** The number of non-compliant meters in metropolitan areas is growing but we are at least able to address a proportion of them. The number of non-compliant meters in regional areas may not be growing as quickly, but we are not able to make any inroads into the backlog due to the limited number and size of crews working in regional SA. This business case therefore considers options to ramp up our resourcing and deploy dedicated crews to clear the backlog across our regional and metropolitan networks in a controlled manner and over an acceptable timeframe.
Untreated risk	As per risk matrix = Moderate (Not ALARP)
Options considered	• **Option 1** – Continue with current practice of reactive rectification to approximately 300 non-compliant meters in the metropolitan network. Relocate

Location	Estimated volume
Adelaide Metropolitan area	100
Port Pirie	111
Mt Gambier	103
Whyalla	275
Total	**589**

meters in the regional networks when budget and resources may be available ($0.7 million)

- **Option 2** – Develop a proactive and planned rectification program for 600 non-compliant meters across both the regional and metropolitan networks, deploying specialist crews to clear the backlog of regional meters as a priority ($2.2 million)
- **Option 3** – Develop a proactive and planned rectification program for 600 known and 300 reactively discovered non-compliant meters (900 total) in metropolitan and regional networks, clearing the backlog in both regional and metropolitan SA and address newly discovered non-compliant meters in metropolitan networks ($3.4 million)

Proposed solution

Option 3 is the proposed solution as it will allow us to address the risk in our regional networks quickly, while offering sufficient operational capacity to keep on top of the non-compliance issue in the metropolitan areas.

Option 1 would not resolve the backlog in regional areas and at best would only maintain the status quo in our metropolitan networks.

Option 2 would offer a risk reduction. However, Option 2 does not effectively address the emerging risks in the metropolitan area, with instances of new non-compliances adding to the inventory at a rate of ~60 per year. We would not be able to address hazards and risks within the five-year timeframe, unnecessarily pushing risk into the next regulatory period.

Estimated cost

The forecast direct cost (excluding overhead) during the next five-year period (July 2026 to June 2031) is $3.4 million.

$`000 Jan 2025	26/27	27/28	28/29	29/30	30/31	Total
Meter set relocation	1,039	584	584	581	584	**3,372**

Alignment to our vision

Relocating identified non-compliant domestic meter sets aligns with AGN’s vision in relation to:

- Being *Customer Focussed*, as proactive treatment of domestic meter sets will help maintain reliability of supply and mitigate the risk of asset failure
- *Operational Excellence* as we are addressing the non-compliant meters at a sustainable rate and utilising an already trained resource base. We will also install venting where the relocation is not practicable, in all instances offering the lowest cost solution commensurate with the risk reduction

Consistency with the National Gas Rules (NGR)

This project complies with the following National Gas Rules (NGR):

NGR 79(1) – The proposed solution is consistent with good industry practice, several practicable options have been considered, and market rates have been tested to achieve the lowest sustainable cost of providing this service.

NGR 79(2) – The proposed capex is justifiable under NGR 79(2)(c)(i) & (iii), as it is necessary to maintain the safety of services and ensure AGN meets the compliance requirements of AS4645.

NGR 74 – The forecast costs are based on the latest market rate testing and project options consider the asset management requirements as per the latest Asset Management Strategy. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.

Treated risk

As per risk matrix = Low

Stakeholder engagement

Our customers have told us their top three priorities are price/affordability, reliability of supply, and maintaining public safety. They also told us they expect AGN to deliver a high level of public safety and are satisfied that this is current practice.

The proposed domestic meter set relocation capital expenditure is a necessary asset safety and compliance program and is therefore consistent with the priorities customers have told us they value. The program will also help maintain reliability of supply at the lowest sustainable cost, minimising the impact on customers’ gas bills.

Other relevant documents

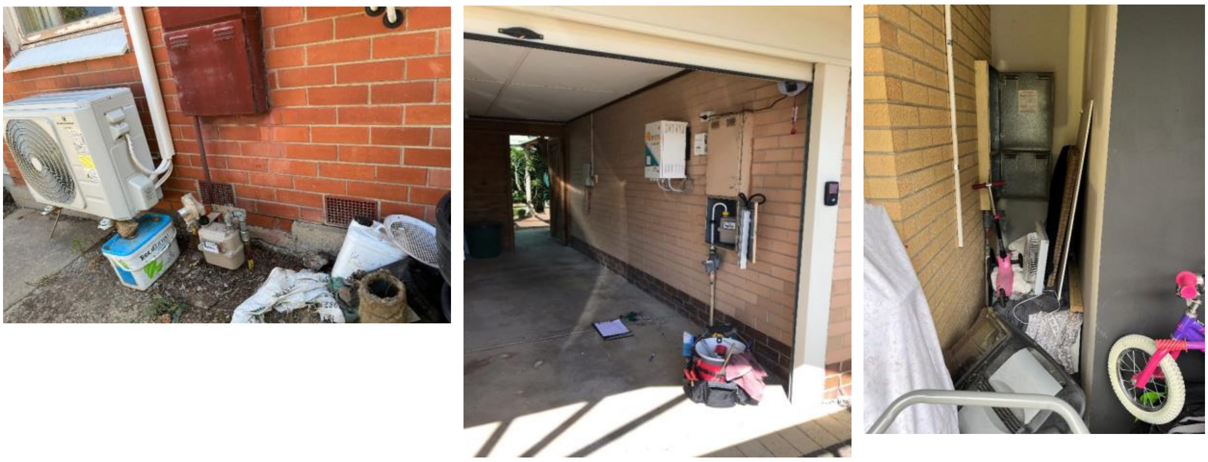
- Attachment 9.3: Asset Management Plan

	• Attachment 9.6: Procurement Policy & Procedure • Attachment 9.10: Unit Rates Report • Attachment 9.11: Risk Management Framework • AS/NZS 4645 Gas Distribution Networks - Part 1: Network Management • AS/NZS 5601 Gas Installations - Part 1: General Installations

1.3 Background

There are number of domestic meter sets within the AGN SA distribution network that do not comply with AS/NZS 4645. Non-compliant meters get reported during periodic meter changes and other normal maintenance works and are typically due to legacy issues, private renovation work or updated compliance standards (see Figure 0.1).

Figure 0.1: Examples of non-compliant meter locations in enclosed areas or near ignition sources



Non-compliance often occurs due to changes around the meter location resulting in ignition sources and enclosed areas. Rectification works typically involve new venting pipework, moving the meter to a compliant location and/or modifying the service line from the main in the street. All these solutions align with industry standard practice.

The non-compliant meter sets identified in this business case are in locations where there are no mains replacement programs scheduled; therefore meters will not be rectified during standard mains and service replacement activities.

Non-compliant meters are prevalent throughout our metropolitan and regional networks. Our metropolitan network, having the largest number of customers, also has the highest instances of non-compliance. In the metropolitan network we record meters in non-compliant locations as we find them and then relocate the meter (or vent the area where relocation is not practicable) when our crews are available. We currently identify around 60 non-compliant meters per year and have a rolling backlog of around 100 meters in the metropolitan area alone.

The issue in our regional networks is subtly different. Recent surveys of our Port Pirie, Mount Gambier and Whyalla networks have identified 489 instances of meters located in non-compliant locations. While this number is significant, the number of non-compliances in the regions is not growing as quickly as in the metropolitan network, simply due to the smaller customer population. This means there is an opportunity to clear the non-compliance issue in the regions with a targeted works program.

Unfortunately, resourcing constraints mean that under current arrangements, we are not able to make significant inroads into clearing the 489-meter backlog. While in the metropolitan areas we have sufficient crews to be able to address most non-compliances (although not all), the crews in our regional networks are smaller and dedicated to day-to-day operations designed to keep the networks operational. The opportunities for these crews to relocate non-compliant meters are few, therefore only the very highest risk meters are addressed, and the remainder stay non-compliant.

Table 0.3 summarises the current non-compliant meter backlog across our South Australian networks.

Table 0.3: Estimated number of non-compliant meters across the metro and regional networks

Location	Estimated volume
Adelaide Metropolitan area	100*
Port Pirie	111
Mt Gambier	103
Whyalla	275
Total	**589**

*Based on historical averages, we expect a further 60 non-compliant meters per year to be found in metropolitan networks.

To clear this backlog of non-compliant meters, we would need to ramp up resources and deploy specialist crews to the regional networks to relocate/vent all the non-compliant meters as part of a proactive program of work. Their focus would be on the meter program only. The regular regional crews would continue to work on day-to-day operational activities on those networks.

1.4 Risk assessment

Risk management is a constant cycle of identification, analysis, treatment, monitoring, reporting and then back to identification. When considering risk and determining the appropriate mitigation activities, we seek to balance the risk outcome with our delivery capabilities and cost implications. Consistent with stakeholder expectations, safety and reliability of supply are our highest priorities.

Our risk assessment approach focuses on understanding the potential severity of failure events associated with each asset and the likelihood that the event will occur. Based on these two key inputs, the risk assessment and derived risk rating then guides the actions required to reduce or manage the risk to an acceptable level.

Figure 0.2: Risk management principles

AGN's risk management framework is based on:

- AS/NZS ISO 31000 Risk Management – Principles and Guidelines
- AS 2885 Pipelines-Gas and Liquid Petroleum
- AS/NZS 4645 Gas Distribution Network Management

The Gas Act 1997 and Gas Regulations 2012, through their incorporation of AS/NZS 4645 and the Work Health and Safety Act 2012, place a regulatory obligation and requirement on AGN to reduce risks rated high or extreme to low or negligible as soon as possible (immediately if extreme). If it is not possible to reduce the risk to low or negligible, then we must reduce the risk to as low as reasonably practicable (ALARP).

Seven consequence categories are considered for each type of risk:

8. **Health & safety** – Injuries or illness of a temporary or permanent nature, or death, to employees and contractors or members of the public
9. **Environment** (including heritage) – Impact on the surroundings in which the asset operates, including natural, built and Aboriginal cultural heritage, soil, water, vegetation, fauna, air and their interrelationships
10. **Operational capability** – Disruption in the daily operations and/or the provision of services/supply, impacting customers
11. **People** – Impact on engagement, capability or size of our workforce
12. **Compliance** – The impact from non-compliance with operating licences, legal, regulatory, contractual obligations, debt financing covenants or reporting / disclosure requirements
13. **Reputation & customer** – Impact on stakeholders' opinion of AGN, including personnel, customers, investors, security holders, regulators and the community
14. **Financial** – Financial impact on AGN, measured on a cumulative basis

Our Risk Management Framework, including definitions, has been provided in Attachment 9.11.

The primary risk event being assessed is that a meter in a non-compliant location causes a gas leak from a venting regulator or leaking fitting, resulting in the accumulation of gas in an enclosed space that could result in a fire/explosion.

The untreated risk[3] rating is presented in Table 0.4.

Table 0.4: Risk rating – Untreated risk

Untreated	Health & Safety	Environment	Operations	People	Compliance	Reputation	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minor	Minor	Minor	Significant	Significant	Minor	
Risk Level	High	Low	Low	Low	Moderate	Moderate	Low	

In certain circumstances, including where a meter is located in an enclosed space, or near an ignition source, a gas leak can have major health and safety consequences, leading to fatality or life threatening injuries. Such an event would lead to significant health and safety, people and reputational risks and could lead to financial penalties. Left untreated, our meter population is non-compliant with our safety obligations.

As a result, the untreated risk associated with non-compliant meter locations is high.

1.5 Options considered

Options considered are:

- **Option 1** – Continue with current practice of reactive rectification of ~300 non-compliant meters in the metropolitan network

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[3] Untreated risk is the risk level assuming there are no risk controls currently in place. Also known as the 'absolute risk'.

- **Option 2** – Develop a proactive and planned rectification program for 600 non-compliant meters across both the regional and metropolitan networks, deploying specialist crews to clear the backlog of regional meters as a priority

- **Option 3** – Develop a proactive and planned rectification program for 900 non-compliant meters in metropolitan and regional networks, clearing the backlog in both regional and metropolitan SA

These options are discussed in the following sections.

1.5.1 Option 1 – Continue with current practice of reactive rectification of ~300 non-compliant meters in the metropolitan network

Under Option 1, we could continue to manage the non-compliant meter issue on a reactive basis, relocating/venting meters as we find them. We assume the historical relocation rate of 60 meters per year would apply in the metropolitan area. No special program would be developed for our regional networks.

Any meters identified to be in a hazardous area during our mains replacement program would be relocated as part of that program. There will be no active relocation of meters not within the vicinity of the mains replacement program.

1.5.1.0 Advantages and disadvantages

The advantage of this option is that it would require no resourcing uplift or significant increase in costs above historical levels.

The disadvantages of this option are that the vast majority of non-compliant meters in our regional networks would go unaddressed, with only the riskiest meters able to be relocated. Further, we would be unlikely to make significant headway into the rolling backlog of 100 non-compliant meters in the metropolitan network. Any newly identified non-compliant meters would be added to the inventory and risk assessed accordingly.

It is also worth noting that the mains replacement program proposed for the next AA period is significantly smaller than in prior periods. This means there will be less opportunity to bundle these reactive works with the ongoing mains and services works.

1.5.1.1 Cost assessment

There are no additional upfront capital costs associated with this option and the rolling budget of approximately $0.7 million would continue. Due to the resource constraints in the regional areas, meters will only be relocated in the Adelaide metropolitan network at the same rate as they are replaced now, or as part of ongoing capital works mains replacement programs.

Maintaining this approach increases the likelihood a risk event will occur due to the volume of meters that are non-compliant which could incur additional rectification costs.

1.5.1.2 Risk assessment

Option 1 results in no significant improvement on the untreated risk position. The risks associated with non-compliant meter locations in the regional networks will effectively remain untreated, and the replacement rate in the metro area will not clear the growing backlog within a reasonable timeframe, if ever.

Table 0.5: Risk rating – Option 1

Option 1	Health & Safety	Environment	Operations	People	Compliance	Reputation	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minor	Minor	Minor	Significant	Significant	Minor	
Risk Level	High	Low	Low	Low	Moderate	Moderate	Low	

Failing to reduce a risk currently rated as moderate to low or to ALARP is not consistent with our risk management framework and does not reflect the practice of a prudent asset manager.

1.5.1.3 Alignment with vision objectives

Table 0.6 shows how this option will support the achievement of our vision objectives.

Table 0.6: Alignment with vision – Option 1

Vision objective	Alignment
Customer Focussed – Public Safety	N
Customer Focussed – Customer Experience	-
Customer Focussed – Cost Efficient	Y
A Leading Employer – Health and Safety	N
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	-
Operational Excellence – Benchmark Performance	Y
Operational Excellence – Reliability	-
Sustainable Communities – Enabling Net Zero	-
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	N

Option 1 would not align with our objective of being *Customer Focussed*, being *A Leading Employer* or *Operational Excellence* as it fails to adequately address the compliance or safety risks to customers and to our employees associated with having meters in enclosed/unventilated areas and/or being near to a source of ignition.

While the lower costs of Option 1 would keep our costs within current benchmarks and therefore be cost efficient over the short term, it can be argued that not addressing the risk and taking almost no action to relocate potentially dangerous meters in our regional networks, would not be consistent with the actions of a socially responsible organisation. This option therefore does not align with our objective to demonstrate *Sustainable Communities*.

1.5.2 Option 2 – Develop a proactive and planned rectification program for ~600 non-compliant meters across both the regional and metropolitan networks, deploying specialist crews to clear the backlog of regional meters as a priority

Under Option 2, we will uplift our resources to relocate ~600 non-compliant meters in the metropolitan and regional networks. Our primary focus under this option will be on clearing the backlog in regional areas. We will establish a specialist crew that can be sent to the regional networks to rectify the non-compliant meters as part of a planned and proactive capital works program. The existing operational teams in those areas will focus on day-to-day activities and maintenance.

The specialist team would also support the metropolitan crews in addressing non-compliant meters, but the priority would be to address the regional issues first. Under this option, we would expect the majority (if not all) regional non-compliances to be addressed within the next AA period.

If we assume the metropolitan instances of non-compliance continue to grow at a rate of 60 per year, we expect the balance of non-compliant meters by the end of the period will have decreased from ~600 to ~300. The outstanding ~300 non-compliant meters will be predominantly in the metropolitan networks, which we would aim to clear in the following five-year periods.

1.5.2.0 Advantages and disadvantages

The advantage of this option is that it would allow us to clear the regional backlog and fully address the non-compliance and safety risks associated with meters in potentially dangerous locations in our Port Pirie, Whyalla and Mount Gambier areas. This would put us in a strong position to manage future non-compliant metering issues in these networks, as we would not expect the rate of new non-compliances in these regions to be high. Put simply, a targeted program in the regions will allow us to get on top of the issue and keep our regional customers safe.

A disadvantage of this option is that the risk in the metropolitan network is not fully cleared. While we would prioritise the riskiest meters for relocation, we would be unlikely to make significant headway into the rolling backlog of 100 non-compliant meters in the metropolitan network. Any newly identified non-compliant meters would be added to the inventory and risk assessed accordingly.

This option would also require an increase in capital costs compared to current levels, however, we would expect to secure resources due to the decrease in mains laying activities over the next period.

1.5.2.1 Cost assessment

The estimated direct cost of this option is $2.2 million. The cost estimate is based on reasonable assumptions for replacement based on the expected complexity of the relocation projects. The estimate is based on current contractor rates and inclusive of project management and engineering costs. It should be noted that there is the potential for a small number of the complex relocation projects to cost considerably more than the estimated average unit rate, however we are planning to manage within the overall allowance.

1.5.2.2 Risk assessment

Relocating all the known non-compliant meters in regional networks will significantly reduce the number of potentially dangerous meters and therefore reduce the likelihood of a risk an incident, however in not addressing the metropolitan meters we have an escalating inventory of non-compliance, which will increase by a further 300. Therefore, the likelihood does not materially change and remains at unlikely. This results in a moderate (not ALARP) rating.

Table 0.7: Risk rating – Option 2

Option 2	Health & Safety	Environment	Operations	People	Compliance	Reputation	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Moderate
Consequence	Major	Minor	Minor	Minor	Significant	Significant	Minor	

Risk Level	Moderate	Negligible	Negligible	Negligible	Low	Low	Negligible	

Option 2 would not meet the requirements of our risk management framework, as it does not reduce the overall risk when considering both regional and metropolitan areas. The risk in metropolitan areas is not eliminated, in fact it escalates, which doesn't position us well to proactively manage risks over a reasonable timeframe.

1.5.2.3 Alignment with vision objectives

Table 0.8 shows how this option will support the achievement of our vision objectives.

Table 0.8: Alignment with vision – Option 2

Vision objective	Alignment
Customer Focussed – Public Safety	N
Customer Focussed – Customer Experience	-
Customer Focussed – Cost Efficient	Y
A Leading Employer – Health and Safety	N
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	-
Operational Excellence – Benchmark Performance	Y
Operational Excellence – Reliability	-
Sustainable Communities – Enabling Net Zero	-
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	N

Option 2 would not align with our objective of being *Customer Focussed*, being *A Leading Employer* or *Operational Excellence* as it fails to adequately address the compliance or safety risks to customers and to our employees associated with having meters in enclosed/unventilated areas and/or being near to a source of ignition.

Option 2 is reflective of *Operational Excellence*, as we would be ramping up resources and delivery rates to a sustainable level, utilising some resource availability from the reduction in mains replacement. While the lower costs of Option 2 would keep our costs within current benchmarks and therefore be cost efficient over the short term, it can be argued that not addressing the known risks would not be consistent with the actions of a socially responsible organisation. This option therefore does not align with our objective to demonstrate *Sustainable Communities*.

1.5.3 Option 3 – Develop a proactive and planned rectification program for 900 non-compliant meters in metropolitan and regional networks, clearing the backlog in both regional and metropolitan SA

In the same manner as Option 2, we would proactively address all the currently known non-compliant meters. However, the increase in resourcing proposed under Option 3 would allow us to clear both the regional and metropolitan backlog within the next five year period.

1.5.3.0 Advantages and disadvantages

The advantage of this option is that it would allow us to clear the regional and metropolitan backlog, fully addressing the known non-compliance and safety risks associated with meters in potentially dangerous locations. It would then put us in a strong position to manage the risk moving forwards.

The disadvantage of this option is the cost and resourcing effort. Under this option we are effectively increasing our current resourcing and delivery capability in this area. However, as the mains replacement activities are significantly reducing we have capacity to increase this program and roll resources efficiently from one program to this.

Delivering the program over five years will allow us sufficient time to schedule and administer the project as well as roll resources into the program without compromising safety, quality or costs.

1.5.3.1 Cost assessment

The estimated direct cost of this option is $3.4 million. The cost estimate is based on reasonable assumptions for replacement based on the expected complexity of the relocation projects. The estimate is based on current contractor rates and inclusive of a project management and engineering cost. It should be noted that there is the potential for a small number of the complex relocation projects to cost considerably more than the estimated average unit rate, however we are planning to manage within the overall allowance.

1.5.3.2 Risk assessment

Option 3 reduces the overall risk rating from moderate to low. Assuming we can clear the regional and metropolitan backlog the likelihood of a meter in a non-compliant location causing an incident would decrease from unlikely to remote by the end of the next five-year period. There would still be non-compliant meters emerging each year due to third-party actions, however we would have capacity to manage them in a timely manner.

Table 0.9: Risk rating – Option 3

Option 3	Health & Safety	Environment	Operations	People	Compliance	Reputation	Finance	Risk
Likelihood	Rare	Rare	Rare	Rare	Rare	Rare	Rare	Low
Consequence	Major	Minor	Minor	Minor	Significant	Significant	Minor	
Risk Level	Low	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	

Option 3 would meet the requirements of our risk management framework, as it effectively reduces the risk associated with non-compliant meters across all our South Australian networks to low, without giving preference to metropolitan or regional customers.

1.5.3.3 Alignment with vision objectives

Table 0.10 shows how this option will support the achievement of our vision objectives.

Table 0.10: Alignment with vision – Option 3

Vision objective	Alignment
Customer Focussed – Public Safety	Y
Customer Focussed – Customer Experience	-
Customer Focussed – Cost Efficient	Y
A Leading Employer – Health and Safety	Y

Vision objective	Alignment
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	-
Operational Excellence – Benchmark Performance	Y
Operational Excellence – Reliability	-
Sustainable Communities – Enabling Net Zero	-
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	Y

Option 3 aligns with our objective of *Customer Focussed*, being *A Leading Employer*, and being *Socially Responsible* as it addresses the safety risk to customers and to our employees associated with having meters in enclosed/unventilated areas or being near to a source of ignition. We are not leaving risks for another than five years by addressing them within the upcoming period.

Option 3 aligns with our objective of *Operational Excellence* as it will efficiently utilise an existing resource base at sustainable delivery rates, avoiding any significant increases in costs.

1.6 Summary of options assessment

Table 0.11 presents a summary of how each option compares in terms of the estimated cost, residual risk rating, and alignment with our objectives.

Table 0.11: Comparison of options

Option	Estimated cost	Treated residual risk rating	Alignment with AGN vision objectives
Option 1	$0.7 million	High	This option does not align with our safety or cost objectives
Option 2	$2.2 million	Moderate – non ALARP	This option does align with our safety and cost objectives for region areas. However, it does not align with our safety or cost objectives for metropolitan areas
Option 3	$3.4 million	Low	This option aligns with our safety or cost objectives for both metro and region areas

1.7 Recommended option

Option 3 is the recommended option as it address the risks to an acceptable level, at a cost commensurate with the risk reduction.

1.7.1 Why is the recommended option prudent?

Option 3 reduces the risk of a gas-in-building event from moderate to low within a reasonable time frame and for an efficient cost. While Option 2 would almost completely eliminate the gas-in-building and ignition risk in the regional areas, we consider leaving the remaining risks in the metropolitan areas to escalate is unacceptable.

This project will be delivered using an internal project manager to manage the schedule, resourcing and budget. An internal engineer would also be utilised for technical and compliance design advice.

In order to complete the regional works, a team from the metropolitan area will be arranged such that regional areas can be completed as dedicated projects in a planned and controlled manner, achieving the most cost-effective economies of scale.

External contractors will be engaged under a competitive tender to complete the relocation works including excavation, reinstatement pipe fitting work and relighting of customers. Records of the changes to meter locations will be updated in Maximo works management system.

The volume of replacements is at a sustainable level for Option 2 and 3 can be optimised alongside the peaks and troughs of seasonal reactive maintenance works.

1.7.2 Estimating efficient costs

The unit rates used for all projects managed within this program include the internal labour, external labour and materials/other costs forecast.

Key assumptions which have been made in the cost estimate include:

- Cost based on historical expenditure noting that these works are not new, with labour rates based on work breakdown structure of activities, and material rates based on historical costs for similar materials
- Estimates derived from contractual rates of vendors to be utilised
- Resource cost based on other similar projects ongoing at present or in previous access arrangement periods

Cost estimates have been based on an assessment of the degree of difficulty associated with pipe alterations at each site and associated unit costs based on similar site relocations undertaken elsewhere in the network.

The average unit rates for each meter replacement includes project management costs, engineering design costs and an estimate of potentially variable costs such as permits and access costs, and costs associated with concrete reinstatement and service route changes. Breakdown of labour and material costs are highlighted in Table 0.12.

Table 0.12: Cost estimate labour & materials, Option 2, $'000 January 2025

	2026/27	2027/28	2028/29	2029/30	2030/31	Total
Labour	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Materials	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	**1,039**	**584**	**584**	**581**	**584**	**3,372**

1.7.3 Consistency with the National Gas Rules

NGR 79(2)

The proposed capex is justifiable under NGR 79(2)(c)(i), as it is necessary to maintain the safety of services. Continuing with current practice results in an unacceptable safety risk for customers. We are also seeking to provide a level of service that meets current industry and design standards.

NGR 79(1)

The relocation of non-compliant domestic gas meters is consistent with the requirements of NGR 79(1)(a). Specifically, we consider that the capital expenditure is:

- **Prudent** – The expenditure is necessary in order to deliver gas safely and reliably to customer outlet points. The proposed risk treatment is consistent with accepted industry practice and current design standards and is proven to address the risk associated with non-compliant domestic meter sets. Several practicable options have been considered to address the risk, and the option that carries a cost most commensurate with the risk reduction has been selected. The proposed expenditure can therefore be seen to be of a nature that would be incurred by a prudent service provider.

- **Efficient** – The forecast expenditure is based on historical average actuals and current materials/labour rate estimates. The development of a dedicated team to address the resource constrained regional areas is the most efficient use of our resources. The proposed expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.

- **Consistent with accepted and good industry practice** – The proposed expenditure follows good industry practice by ensuring that existing safety risks are addressed to as low as reasonably practicable, over a reasonable timeframe and in line with current industry practice and design standards.

- To achieve **the lowest sustainable cost of delivering pipeline services** – The selected solution is the lowest cost option and seeks to achieve a reasonable balance between risk reduction and price.

NGR 79(2)

The proposed capex is justifiable under NGR 79(2)(c)(i), as it is necessary to maintain the safety of services. As outlined in the business case, continuing with current practice results in an unacceptable operation and compliance risk for customers and AGN is seeking to maintain a level of service consistent with industry and design standards.

NGR 74

The forecast costs and are based on the latest market rate testing and project options consider the asset management requirements as per the latest Asset Management Plan. Cost assessments have been conducted for each option. The estimate has been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.

Appendix A – Comparison of risk assessment for each option

Untreated	Health & Safety	Environment	Operations	People	Compliance	Reputation	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minor	Minor	Minor	Significant	Significant	Minor	
Risk Level	High	Low	Low	Low	Moderate	Moderate	Low	

Option 1	Health & Safety	Environment	Operations	People	Compliance	Reputation	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minor	Minor	Minor	Significant	Significant	Minor	
Risk Level	High	Low	Low	Low	Moderate	Moderate	Low	

Option 2	Health & Safety	Environment	Operations	People	Compliance	Reputation	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Moderate
Consequence	Major	Minor	Minor	Minor	Significant	Significant	Minor	
Risk Level	Moderate	Negligible	Negligible	Negligible	Low	Low	Negligible	

Option 3	Health & Safety	Environment	Operations	People	Compliance	Reputation	Finance	Risk
Likelihood	Rare	Rare	Rare	Rare	Rare	Rare	Rare	Low
Consequence	Major	Minor	Minor	Minor	Significant	Significant	Minor	
Risk Level	Low	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	

SA203 – Isolation valves

1.1 Project approvals

Table 0.1: Business case SA203 – Project approvals

Prepared by	Hsuan Chen – Graduate Engineer
Technical SME	Hossein Ghanbari Adivi – Pipeline Integrity Engineer
Reviewed by	Alan Creffield – Manager, Integrity
Approved by	Michael Iapichello – Head of Engineering and Planning (14/5/25) Nick Kafamanis – Head of Networks Capital Delivery (05/06/2025)

1.2 Project overview

Table 0.2: Business case SA203 – Project overview

Description of the problem / opportunity	The South Australia (SA) natural gas distribution networks include transmission pressure (TP) pipelines and distribution pressure (DP) pipelines, which deliver gas to over 485,000 customers. The current TP & DP systems in the Adelaide metro area are interconnected. This interconnectivity facilitates the security of gas supply in the networks. Australian Standards 2885 and 4645 require transmission pipeline and distribution network operators to install and maintain isolation valves to allow the pipeline or network to be isolated for emergency and maintenance purposes. Valves also allow for flexibility to help ensure security of supply when flow dynamics must be altered to accommodate growth or potential network pressure issues. There are 1,207 steel valves in the SA networks. Of these, 283 valves are located on TP pipelines and 924 in the smaller DP mains. Most of the valves were installed in the 1970s and 1980s and are typically located in medium and high-density suburban areas. We have an ongoing valve replacement program, where we address seized/failed as we discover them through periodic testing. Historically we have replaced 4-5 valves per year. However, this historical rate of replacement has proven insufficient to stay on top of the problem, resulting in a backlog of 38 valves that we know are inoperable but have not yet been replaced. Assuming the historical failure rate of 4-5 valves continues, unless we uplift our replacement volumes, the backlog of failed valves will continue to grow. We therefore propose to start a dedicated program whereby we will clear the backlog (as well as addressing newly failed valves we detect), most likely over ten years. We will also install 2 new isolation valves on the M42 TP pipeline, either side of the Torrens River crossing. As discussed in business case SA204, the Torrens River bridge structure is 60 years old and is showing signs of corrosion. It requires inspection and potential remediation. There are no valves near this crossing. Given the criticality of the M42 pipeline (which supplies >2,000 customers and a large I&C customer) and the age/disrepair of the bridge, we consider it prudent to be able to isolate this river crossing section. Installing these 2 isolation valves will enable us to close off this section quickly in the event the bridge structure and pipeline fails and/or needs timely isolation.
Untreated risk	As per risk matrix = High
Options considered	• **Option 1** – Historical replacement rate: continue historical valve testing and replacement rate of 4 per year, and install 2 new TP valves at the M42 bridge ($7.0 million) • **Option 2 –** Clear backlog in ten years: uplift replacement rate to clear backlog over the next two AA periods, and install 2 new TP valves at the M42 bridge ($12.4 million) • **Option 3** – Clear backlog in five years: uplift replacement rate to clear backlog by the end of the next AA period, and install 2 new TP valves at the M42 bridge ($15.6 million)

Proposed solution

Option 2 is the proposed solution because:

- It addresses security of supply risks associated with inoperable valves and sensitive sections of the pipeline (Torrens River crossing)
- It will help reduce emergency repair costs over the long term
- Option 2 reduces the risk over a 10-year period with a balanced program of works.
- Option 3 likely to incur escalating costs due to the availability of resources
- Option 1 is untenable from a risk perspective

Estimated cost

The forecast direct cost (excluding overhead) during the next five-year period (July 2021 to June 2026) is $12.4 million (Jan 2025).

$'000 Jan 2025	26/27	27/28	28/29	29/30	30/31	Total
Isolation valves	1,881	2,315	2,518	3,343	2,315	**12,372**

Basis of costs

All costs in this business case are expressed in real unescalated dollars at January 2025 unless otherwise stated.

Treated risk

As per risk matrix = Moderate (ALARP)

Alignment to our vision

This project aligns with our vision objective of being *Customer Focussed*. It delivers for customers by ensuring security and reliability of gas supply, particularly during emergency situations.

It also aligns with our *Operational Excellence* vision objective. Replacing valves is the most cost-effective solution to this issue, with the long term costs of a reactive valve replacement being greater than proactive replacement.

Consistency with the National Gas Rules (NGR)

This project complies with the following National Gas Rules (NGR):

NGR 79(1) – the proposed solution is consistent with good industry practice, several practicable options have been considered, and market rates have been tested to achieve the lowest sustainable cost of providing this service.

NGR 79(2) – proposed capex is justifiable under NGR 79(2)(c)(ii), as it is necessary to maintain the integrity of services.

NGR 74 – the forecast costs are based on the latest market rate testing and project options consider the asset management requirements as per the Asset Management Strategy. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.

Stakeholder engagement

Our customers have told us their top three priorities are price/affordability, reliability of supply, and maintaining public safety. They also told us they expect us to deliver a high level of public safety and are satisfied that this is current practice.

The proposed valve replacement program is a continuation of proactive asset management, which results in lower long-term costs than maintaining a reactive treatment program.

Undertaking the proposed valve replacement program will also help maintain reliability of supply at the lowest sustainable cost, minimising the impact on customers' gas bills.

Other relevant documents

- Asset Management Strategy – AGN South Australia Networks – 420-PL-AM-0010

1.3 Background

The SA natural gas distribution networks include approximately 200 km of steel TP pipelines and 8,500 km of distribution pipelines, which deliver gas to over 485,000 customers.

AS 2885 and AS/NZS 4645 require transmission pipeline and distribution network operators to install and maintain isolation valves to allow the pipeline or network to be isolated for emergency and maintenance purposes, this includes provisions for special construction where a pipeline is, for example, above ground at locations such as bridges. Valves also allow for control flexibility to help ensure security of supply.

Valves are strategically placed to allow critical assets such as district regulator stations (DRS) and demand customer meter sets to be isolated without materially impacting the rest of the network. The quantity and location of valves depends on the asset design, pipe material, operating pressure, pipeline criticality level, supply impact, and potential consequences of a loss of containment (urban vs rural).

There are 1,207 steel valves in the SA networks. Of these, 283 valves are located on TP pipelines, and 924 in the smaller distribution mains. Most were installed in the 1970s and 1980s during the original pipeline construction and are typically located in medium and high-density suburban areas. All steel valves are susceptible to corrosion, which can result in seizing or leaking. The risk of corrosion depends on the valve location, environmental conditions, coating degradation, level of maintenance, and whether the cathodic protection system is effective.

The highest-risk family of valves are large diameter valves (>150mm) housed in underground concrete or brick chambers. These valves are accessed via manholes located in the roadway or footpaths. Valves in chambers are particularly susceptible to corrosion, as the chambers often collect water, which can create a humid environment conducive to corrosion. These valves are typically not protected by the pipeline's cathodic protection system (whether impressed current or sacrificial anode) because they are not in direct contact with the soil and therefore cannot form the necessary electrical connection for protection.

Smaller valves not located in chambers can also be susceptible to corrosion. As valves age, components such as the valve key and shaft corrode, the valve plug can irreparably seize, and the flange gaskets deteriorate. Some valves cannot be visually inspected for damage or corrosion unless excavated.

1.3.1 Inoperable valves

An inoperable valve is one that does not stop the flow of gas to isolate the network, either because it has seized and cannot be turned, or because it does not fully isolate supply when operated. Inoperable valves pose a high risk to security of supply.

If a valve cannot be closed (or opened) to isolate a section of network/pipeline, using an alternative valve upstream or downstream could result in significantly more customers being impacted than would otherwise be necessary. Flow-stopping high-pressure mains when a valve is inoperable takes considerable time to excavate, prepare the main, and insert stopples to halt the flow of gas.

Generally, isolation of supply has the potential to affect gas supply of more than 50,000[4] customers for transmission valves and up to 5,000 customers for major gas distribution valves.

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[4] For example, on critical pipelines such as M42.

We have identified 38 currently inoperable valves that require attention, of which 8 are on TP pipelines and 30 are in the DP networks. A list of the inoperable valves is provided in Appendix A.

1.3.1.0 Valve replacement

We have an ongoing isolation valve management program whereby we periodically test valves and flag them for replacement if they are seized and cannot be freed. Once flagged, we go back and replace these valves as part of a scheduled replacement program.

Replacing an inoperable valve is proposed when all other options for repair have been exhausted. We will attempt a repair where safe to do so, noting that a repaired valve will typically be weakened and is likely to leak in the future. However, if the valve is seized or the integrity of the valve has been compromised such that it is irreparable, we will replace that valve completely.

Historically, we replace 4-5 valves per year. However, as the asset ages, this historical rate of replacement has been insufficient to keep pace with the number of failed valves. We are therefore now in the position where there are 38 valves (8 TP and 30 DP) we know of that are seized/inoperable (~2% of the valve population). This backlog of failed valves is in addition to the 4-5 per year we expect to find during valve testing.

We therefore propose to uplift the valve replacement program and commence clearing this backlog, as well as addressing the failed valves we find during the AA period. Reducing the backlog of valves over a reasonable timeframe will allow us to balance replacements with the valve seizure/failure rates, and ensure the risk is managed back to as low as reasonably practicable (ALARP).

1.3.2 New isolation valves

New valves are installed where a supply risk has been identified and/or where a loss of supply would impact >50,000 customers or a demand customer. This is an ongoing program and is established standard practice.

Only one location for the upcoming regulatory period has been identified as requiring new isolation valves: the Torrens River crossing on the M42 TP pipeline.

As discussed in business case SA204, where the M42 pipeline crosses the Torrens River, it is supported by a steel structure that forms a bridge. The bridge structure is welded to the pipeline, forming a single integrated asset. This bridge crossing is unique as the combined pipeline and bridge structure is owned by AGN. For all other bridge crossings, the bridge is owned and maintained by a third party and AGN maintains the pipeline only.

The pipeline structure was installed in 1968 and there are no records of it being inspected since. This section of the M42 pipeline is unpiggable. Recent visual inspections have identified corrosion on the bridge structure, and its structural integrity is not known.

Should the structure fail, more than 2,000 customers and a demand customer would be affected. Given the age and unknown condition of the Torrens River crossing, coupled with the complexities of inspecting and remediating this section, we consider it prudent to install isolation valves either side of the bridge.

This will allow us to isolate supply quickly in the event the bridge does fail. It will also assist in subsequent remedial works on the pipeline structure, allowing us to manage supply to customers in the least disruptive manner.

1.4 Risk assessment

Figure 0.1: Risk management principles

Risk management is a constant cycle of identification, analysis, treatment, monitoring, reporting and then back to identification. When considering risk and determining the appropriate mitigation activities, we seek to balance the risk outcome with our delivery capabilities and cost implications. Consistent with stakeholder expectations, safety and reliability of supply are our highest priorities.

Our risk assessment approach focuses on understanding the potential severity of failure events associated with each asset and the likelihood that the event will occur. Based on these two key inputs, the risk assessment and derived risk rating then guides the actions required to reduce or manage the risk to an acceptable level.

Our risk management framework is based on:

- AS/NZS ISO 31000 Risk Management – Principles and Guidelines,
- AS 2885 Pipelines-Gas and Liquid Petroleum; and
- AS/NZS 4645 Gas Distribution Network Management.

The Gas Act 1997 and Gas Regulations 2012, through their incorporation of AS/NZS 4645 and the Work Health and Safety Act 2012, place a regulatory obligation and requirement on us to reduce risks rated high or extreme to low or negligible as soon as possible (immediately if extreme). If it is not possible to reduce the risk to low or negligible, then we must reduce the risk to as low as reasonably practicable (ALARP).

When assessing risk for the purpose of investment decisions, rather than analysing all conceivable risks associated with an asset, we look at a credible, primary risk event to test the level of investment required. Where that credible risk event has an overall risk rating of moderate or higher, we will undertake investment to reduce the risk.

Seven consequence categories are considered for each type of risk:

15. **Health & safety** – injuries or illness of a temporary or permanent nature, or death, to employees and contractors or members of the public
16. **Environment** (including heritage) – impact on the surroundings in which the asset operates, including natural, built and Aboriginal cultural heritage, soil, water, vegetation, fauna, air and their interrelationships
17. **Operational capability** – disruption in the daily operations and/or the provision of services/supply, impacting customers
18. **People** – impact on engagement, capability or size of our workforce
19. **Compliance** – the impact from non-compliance with operating licences, legal, regulatory, contractual obligations, debt financing covenants or reporting / disclosure requirements
20. **Reputation & customer** – impact on stakeholders' opinion of AGN, including personnel, customers, investors, security holders, regulators and the community
21. **Financial** – financial impact on AGN, measured on a cumulative basis

The primary risk event considered in this business case is that during an emergency (or planned maintenance) situation, we find that the valve necessary to isolate that section of pipeline is inoperable, meaning we need to isolate a greater number of customers and therefore impact gas supply to >10,000 customers or a demand customer >10 TJ p.a.

The risk consequence category most impacted by inoperable or a lack of valves is Operational capability (Operations or supply). The untreated risk is rated high (see Table 0.3). The health and safety risk associated with inoperable valves is moderate, as a seized (inoperable) valve does not necessarily mean a leak is present.

Table 0.3: Risk rating – untreated risk

Untreated risk	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Significant	Minimal	Major	Minimal	Minor	Minor	Minor	
Risk Level	Moderate	Negligible	High	Negligible	Low	Low	Low	

The likelihood of the primary risk event occurring will increase with time if the condition of these valves is not addressed.

1.5 Options considered

We have identified the following options to address the risks associated with inoperable valves:

- **Option 1** – Historical replacement rate: continue historical valve testing and replacement rate of 4 per year, and install 2 new TP valves at the M42 bridge
- **Option 2** – Clear backlog in ten years: uplift replacement rate to clear backlog over the next two AA periods, and install 2 new TP valves at the M42 bridge
- **Option 3** – Clear backlog in five years: uplift replacement rate to clear backlog by the end of the next AA period, and install 2 new TP valves at the M42 bridge

We have included provision for installing the 2 new M42 bridge valves in all options. We considered excluding the new M42 valves from the program, but given the age of the bridge, unknown condition of the pipeline structure, and criticality of the M42 pipeline, we considered it prudent to install the valves in any event. Having the ability to isolate sensitive/high risk areas of our network is good asset management practice and helps mitigate risk in all circumstances.

1.5.1 Option 1 – Historical replacement rate

Under Option 1 we would maintain the current replacement rate of 4 valves per year. Inoperable valves would be flagged for replacement and would be prioritised based on risk and whether we are likely to need to operate the valves in the near future to conduct network maintenance/repairs. Any seized valves would continue to be maintained to the extent possible, in the hope they can be freed and can come back to operational use.

Under Option 1 we would install two new isolation valves, either side of the Torrens River bridge crossing.

1.5.1.0 Advantages and disadvantages

The advantage of this option is that it would require no significant uplift in delivery rates or cost. Work crews would continue with current schedules and practices. Installing the two new valves on the M42 pipeline would mitigate the risk of bridge failure.

The disadvantage of this option is that it would not allow us to clear the backlog of seized valves. Unless the number of newly seized/failed valves declines sharply, only replacing 4 per year would not make any significant headway into addressing the 38 valves we know are already inoperable. Under Option 1 we are relying on valve failure rates to decrease without uplifting our replacement rates, which is counterintuitive as valve failures are likely to become more common as the assets age.

In the event we need to operate one of the 38 identified valves in an emergency, we run the risk of having to impact supply to thousands more customers than is necessary.

1.5.1.1 Cost assessment

The estimated direct capital cost of this option is $7.0 million as shown in Table 0.4 assuming replacement of 1 TP valve and 3 DP valves per year.

Table 0.4: Cost estimate – Option 1 $'000 January 2025

Activity	Scope	2026/27	2027/28	2028/29	2029/30	2030/31	Total
Valve replacement	4 valves per year	1,157	1,158	1,157	1,158	1,157	5,787
New valves	x2 valves at M42 Torrens River crossing	-	-	203	1,028	-	1,231
Total		**1,157**	**1,158**	**1,360**	**2,186**	**1,157**	**7,018**

1.5.1.2 Risk assessment

Option 1, while offering a greater risk control than the untreated risk scenario, does not reduce the overall risk rating. By continuing what is effectively a subsistence level of valve replacement, the risk associated with valve failure will continue to escalate as the backlog of inoperable valves grows, with this approach moving the likelihood from remote to unlikely, resulting in a high risk. This option does, however, address the security of supply risks associated with the Torrens River crossing.

The risk rating under this option is shown in Table 0.5.

Table 0.5: Risk rating – Option 1

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Significant	Minimal	Major	Minimal	Minor	Minor	Minor	
Risk Level	Moderate	Negligible	High	Negligible	Low	Low	Low	

Valves will only be replaced where they are high priority and/or pose a significant health and safety risk through excessive leakage. As a result, many of the inoperable valves will remain in the networks. This increases the likelihood to cause significant disruption to large numbers of customers if emergency works are required and sections of pipeline cannot be isolated.

1.5.1.3 Alignment with vision objectives

Table 0.12 shows how Option 1 aligns with our vision objectives.

Table 0.6: Alignment with vision – Option 1

Vision objective	Alignment
Customer Focussed - Public Safety	N
Customer Focussed – Customer Experience	-
Customer Focussed – Cost Efficient	Y
A Leading Employer – Health and Safety	-
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	-
Operational Excellence – Benchmark Performance	-
Operational Excellence – Reliability	N
Sustainable Communities – Enabling Net Zero	-
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	-

Option 1 would not align with our objective of being *Customer Focussed*, as it would not address the increased number of customers at risk in an emergency situation due to inoperable valves.

Allowing valves to fail and potentially giving rise to outages would also be inconsistent with our aim of providing a reliable service. This option therefore does not align with our objective to practice *Operational Excellence*.

1.5.2 Option 2 – Clear backlog in ten years: uplift replacement rate to clear backlog over the next two AA periods, and install 2 new TP valves at the M42 bridge

Under Option 2 we would uplift the valve replacement rate to 8 per year. This would allow us to keep pace with the historical valve failure rate, while addressing a further 4 valves per year from the 38-valve backlog. At that rate we would clear half the backlog in the next AA period, with the balance to be cleared over the following AA period (see Table 0.7).

Table 0.7: Forecast replacement rates of valves under Option 2

Year	Known valves to be replaced	Provision for failed valves	Valves replacements required per year	Total backlog of failed valves
2026/27	4	4	8	34
2027/28	4	4	8	30
2028/29	4	4	8	26
2029/30	4	4	8	22
2030/31	4	4	8	18
2031/32	4	4	8	14
2032/33	4	4	8	10
2033/34	4	4	8	6
2034/35	4	4	8	2
2035/36	4	4	8	0

Seized valves would continue to be maintained to the extent possible, in the hope they can be freed and can come back to operational use.

Under Option 2 we would install two new isolation valves on the M42 Pipeline, either side of the Torrens River bridge crossing.

1.5.2.0 Advantages and disadvantages

The advantage of this option is that it will allow us to clear the inoperable valve backlog over approximately 10 years. Though we would effectively be doubling our valve replacement rate compared to the current AA period, we consider this is a manageable and sustainable uplift. We are confident we can scale up resources to conduct the extra work with minimal disruption to our broader works program. Installing the two new valves on the M42 pipeline would mitigate the risk of bridge failure.

The disadvantage of this option is the additional cost compared with Option 1.

1.5.2.1 Cost assessment

The estimated direct capital cost of this option is $12.4 million as shown in Table 0.8.

Table 0.8: Cost estimate – Option 2 $'000 January 2025

Activity	Scope	2026/27	2027/28	2028/29	2029/30	2030/31	Total
Valve replacement	8 valves per year	1,881	2,315	2,315	2,315	2,315	11,140
New valves	x2 valves at M42 Torrens River crossing	-	-	203	1,028	-	1,231
Total		**1,881**	**2,315**	**2,518**	**3,343**	**2,315**	**12,372**

1.5.2.2 Risk assessment

Option 2 reduces the risk from high to moderate (ALARP). This is because replacing the currently inoperable valves decreases the potential number of customers that would be impacted during emergency repairs. This reduces the risk consequence for *Operational Capability* to major. As the inoperable valves are identified and rectified, the likelihood of us finding that the isolation valve is inoperable during an emergency situation is reduced to remote. This option also addresses the security of supply risks associated with the Torrens River crossing.

The residual risk outcomes are shown in Table 0.9.

Table 0.9: Risk rating – Option 2

Option 2	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Moderate ALARP
Consequence	Significant	Minimal	Major	Minimal	Minor	Minor	Minor	
Risk Level	Low	Negligible	Moderate	Negligible	Negligible	Negligible	Negligible	

1.5.2.3 Alignment with vision objectives

Table 0.10 shows how Option 2 aligns with our vision objectives.

Table 0.10: Alignment with vision – Option 2

Vision objective	Alignment
Customer Focussed - Public Safety	Y

Vision objective	Alignment
Customer Focussed – Customer Experience	-
Customer Focussed – Cost Efficient	Y
A Leading Employer – Health and Safety	-
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	Y
Operational Excellence – Benchmark Performance	-
Operational Excellence – Reliability	Y
Sustainable Communities – Enabling Net Zero	-
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	-

Option 2 would align with the *Customer Focussed* aspect of our vision, as replacement of inoperable valves will help maintain reliability of supply to more customers, particularly during emergency situations.

The proposed solution also reflects Operational Excellence as it achieves a good balance between risk reduction and cost increases. The uplift in cost and resources is deliverable and sustainable, allowing us to clear the backlog of inoperable valves over a reasonable timeframe and spreading the cost over two AA periods.

1.5.3 Option 3 – Clear backlog in five years: uplift replacement rate to clear backlog by the end of the next AA period, and install 2 new TP valves at the M42 bridge

Under option 3 we would uplift the valve replacement rate to 12 per year. This would allow us to keep pace with the historical valve failure rate, while addressing a further 8 valves per year from the 38-valve backlog. At that rate we would clear the full backlog in the next AA period (see Table 0.11).

Table 0.11: Forecast replacement rates of valves under Option 3

Year	Known valves to be replaced	Provision for failed valves	Valves replacements required per year	Total backlog of failed valves
2026/27	8	4	12	30
2027/28	8	4	12	22
2028/29	8	4	12	14
2029/30	8	4	12	6
2030/31	6	4	10	0

Seized valves would continue to be maintained to the extent possible, in the hope they can be freed and can come back to operational use.

Under Option 3 we would install two new isolation valves on M42 pipeline, either side of the Torrens River bridge crossing.

1.5.3.0 Advantages and disadvantages

The advantage of this option is that it will allow us to clear the inoperable valve backlog within one AA period. Installing the two new valves on the M42 pipeline would mitigate the risk of bridge failure.

The disadvantage of this option is the additional cost. Under Option 3 we are effectively tripling our valve replacement program. While we believe we could scale up to this rate, it is at the very limits of our delivery capability. Even though the program would benefit from economies of scale, there is a finite resource pool to undertake these activities. As such there is a deliverability risk and a reasonable likelihood that the unit rates would escalate from the current forecast if we were to commit to delivering the entire program in one period. Further, the impact on regulated tariffs in would be sharper than under Option 2 as the entire capital program would be added to the regulatory asset base after only one AA period.

1.5.3.1 Cost assessment

The estimated direct capital cost of this option is $15.6 million as shown in Table 0.12.

Table 0.12: Cost estimate – Option 3 $'000 January 2025

Activity	Scope	2026/27	2027/28	2028/29	2029/30	2030/31	Total
Valve replacement	12 valves per year (10 in Year 5)	2,603	3,037	3,037	3,037	2,679	14,393
New valves	x2 valves at M42 Torrens River crossing	-	-	203	1,028	-	1,231
Total		**2,603**	**3,037**	**3,239**	**4,066**	**2,679**	**15,624**

1.5.3.2 Risk assessment

Option 3 achieves the same risk reduction as Option 2 but does so over a shorter timeframe (see Table 0.13). This option also addresses the security of supply risks associated with the Torrens River crossing.

Table 0.13: Risk rating – Option 3

Option 3	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Moderate (ALARP)
Consequence	Significant	Minimal	Major	Minimal	Minor	Minor	Minor	
Risk Level	Low	Negligible	Moderate	Negligible	Negligible	Negligible	Negligible	

1.5.3.3 Alignment with vision objectives

Table 0.14 shows how Option 3 aligns with our vision objectives.

Table 0.14: Alignment with vision – Option 3

Vision objective	Alignment
Customer Focussed - Public Safety	Y
Customer Focussed – Customer Experience	-
Customer Focussed – Cost Efficient	Y
A Leading Employer – Health and Safety	-
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	N
Operational Excellence – Benchmark Performance	N
Operational Excellence – Reliability	Y

Vision objective	Alignment
Sustainable Communities – Enabling Net Zero	-
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	-

Option 3 would align with the *Customer Focussed* aspect of our vision, as replacement of inoperable valves will help maintain reliability of supply to more customers, particularly during emergency situations.

However, it could be argued that this option does not reflect *Operational Excellence* as the uplift in resourcing is significant and would be difficult to sustain. Option 3 also represents the highest cost increase.

1.6 Summary of options assessment

Table 0.15: Comparison of options

Option	Estimated cost ($ million January 2025)	Treated residual risk rating	Alignment with vision objectives
Option 1	7.0	High	Does not align with *Customer Focussed* or *Operational Excellence*
Option 2	12.4	Moderate (ALARP)	Aligns with *Customer Focussed* and *Operational Excellence*
Option 3	15.6	Moderate (ALARP)	Aligns with *Customer Focussed* but does not align with *Operational Excellence*

1.7 Proposed solution

Option 2 is the proposed solution. This project will be delivered using an internal project manager to manage the schedule, resourcing and budget, with the work split between internal operations crews and external contractors. Contractors will be engaged based on a competitive tender process. Once a valve is replaced the relevant records will be updated in the geospatial information system

A risk to project delivery will be the availability of resources. However, current project delivery practices and controls such as advanced planning and scheduling of work are in place to effectively manage this risk. The risk of not completing this project is considered to be low.

1.7.1 Why is the recommended option prudent?

Option 2 is proposed because:

- It is consistent with AS 2885 and AS/NZS 4645, with strategically placed (operable) valves providing control flexibility to help ensure security of supply
- It addresses the risks associated with inoperable isolation valves over a reasonable timeframe at a sustainable rate
- It is the most cost-effective way of managing the risks associated with the seized valves

To not replace the inoperable valves would expose us to much higher costs in the event of an emergency incident. An emergency incident would require the mobilisation of a specialist emergency repair contractor with a minimum mobilisation time of 24 hours and the closure of alternative isolation valves or timely and expensive live high pressure mains flow stopping techniques. Closure of alternative isolation valves would affect a greater number of customers, particularly in the Adelaide CBD. It could also lead to relatively high rectification costs, given the costs associated with relighting. We estimate reactive replacement costs around three times that of proactive replacement. We consider the valve replacement program is deliverable within the next access arrangement period.

1.7.2 Estimating efficient costs

The unit rates used for all projects managed within this program includes the internal labour, external labour and materials/other costs.

The volume of work proposed is based on the currently identified number of TP and distribution inoperable valves plus the anticipated failure rate, with a total of 9 TP and 31 DP valves proposed for replacement. Replacements have been spread evenly across the access arrangement period with the new valve installation occurring in year 4.

Unit rates for valve replacements are provided in Table 0.16Table 0.16. These are based on the following assumptions:

- TP valves typically require a bypass installed to ensure continuity of gas supply downstream. The requirement for a bypass is based on numerous factors, including the number of customers impacted, the time of year and the network configuration. While each location will be individually assessed prior to the project starting, historical precedent from valve and other pipeline works suggests that bypasses will be required for most TP valves; and
- the estimated valve replacement costs are based on a bottom-up estimate informed by the actual costs of recently completed projects:
  - Transmission valve – V752 2023/24 $607k
  - Distribution valve - V73 2023/24 $172k

These projects represent a reasonable basis for the forecast estimate because the proposed works are very similar in nature for both labour and materials requirements. The estimated cost per valve type is provided in Appendix B.

Table 0.16: Unit rates – $'000 January 2025

	Transmission pressure (TP)	Distribution (DP)
Labour	[redacted]	[redacted]
Materials	[redacted]	[redacted]
Total	[redacted]	[redacted]

The outcome from applying the forecast cost to the forecast volumes is an estimated capital cost of replacing these 40 valves and installing 2 new valves of $12,371,971, as shown in Table 0.17 below.

Table 0.17: Cost estimate – Option 2, $'000 January 2025

Option 2	2026/27	2027/28	2028/29	2029/30	2030/31	Total
TP						
Labour	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Materials	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Distribution						
Labour	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Materials	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

1.7.3 Consistency with the National Gas Rules

In developing these forecasts, we have had regard to Rule 79 and Rule 74 of the NGR. With regard to all projects, and as a prudent asset manager, we give careful consideration to whether capex is conforming from a number of perspectives before committing to capital investment.

NGR 79(1)

The proposed solution is prudent, efficient, consistent with accepted and good industry practice and will achieve the lowest sustainable cost of delivering pipeline services:

- **Prudent** – The expenditure is necessary in order to ensure that TP and DP valves are operable for emergency isolation and pressure control. Failure to address the inoperable valves could result in isolation of a larger than necessary section of pipeline in an emergency situation, therefore increasing the number of customers cut off from supply. The proposed expenditure is therefore consistent with that which would be incurred by a prudent service provider.

- **Efficient** – Replacement of these valves is the only practical and cost-effective option. Costs have been based on recent similar valve replacement projects. Where contractors are engaged, this will be based on a competitive tender process. The expenditure is therefore consistent with what a prudent service provider acting efficiently would incur.

- **Consistent with accepted and good industry practice** – Maintaining critical isolation valves for emergency control is consistent with Australian Standard AS 2885.3 Pipelines - Gas and Liquid Petroleum, Part 3: Pipeline Integrity Management and AS/NZS 4645 distribution. Reducing the risks posed by inoperable valves in a manner that balances costs and risks is also consistent with these standards. We therefore consider the proposed capital expenditure is in accordance with accepted good industry practice.

- **To achieve the lowest sustainable cost of delivering pipeline services** – The valve replacement works are necessary to maintain the long term integrity of the pipelines. Failure to do so could result in additional expenditure (reactive response to a safety critical valve failure). The project is therefore consistent with the objective of achieving the lowest sustainable cost of delivering services.

NGR 79(2)

The proposed capex is justifiable under 79(2)(c)(ii), as it is necessary to maintain the integrity of services. Allowing the number of inoperable valves to continue to grow will lead to an increasing number of customers at risk of supply in an emergency isolation situation.

NGR 74

The forecast costs are based on the latest market rate testing and project options consider asset management requirements as per the Asset Management Strategy. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.

Appendix A – List of inoperable valves to be replaced

List of inoperable steel valves for Option 2

Priority	Pressure tier	Valve number	Location
Transmission valves			
1	T1	57	Newland Ave, Marino
2	T1	506	3 Columbia Crt, Hallet Cove
3	T1	753	Langham Pl (Port Adelaide)
4	T1	858	1142 Old Port Rd, Hendon
5	T1	1482	3 Cormack Rd, Wingfield
6	T1	R210	Kettering Rd, Elizabeth South
7	T1	R216A	May Terrace, Ottoway
8	T1	R216B	May Terrace, Ottoway
Distribution valves			
1	H1	98	Strangways Tce
2	H1	435	Black Rd, O'Halloran Hill
3	H1	165	Bains Rd (Sedunary Rd)
4	H1	597	Windebanks Rd, Happy Valley
5	H1	807	Coromandel Pde, Blackwood
6	H1	1465	Tozer and Ryan Rd Waterloo
7	H1	5853806	Winchester St, St Peters
8	M2	123	Seaview Rd (cnr Grange Rd)
9	M2	232	Grand Junction Rd
10	M2	358	Kingston Ave, Hope Valley
11	M2	967	Port Rd, Woodville
12	M2	1079	Clairville Rd, Newton

List of inoperable steel valves for Option 3

	Pressure Tier	Valve Number	Location
Transmission Valves			
1	T1	57	Newland Ave, Marino
2	T1	506	3 Columbia Crt, Hallet Cove
3	T1	753	Langham Pl (Port Adelaide)
4	T1	858	1142 Old Port Rd, Hendon
5	T1	1482	3 Cormack Rd, Wingfield
6	T1	R210	Kettering Rd, Elizabeth South
7	T1	R216A	May Terrace, Ottoway
8	T1	R216B	May Terrace, Ottoway
Distribution Valves			
1	H1	98	Strangways Tce
2	H1	435	Black Rd, O'Halloran Hill
3	H1	165	Bains Rd (Sedunary Rd)
4	H1	597	Windebanks Rd, Happy Valley
5	H1	807	Coromandel Pde, Blackwood
6	H1	1465	Tozer and Ryan Rd Waterloo
7	H1	5853806	Winchester St, St Peters
8	M2	123	Seaview Rd (cnr Grange Rd)
9	M2	232	Grand Junction Rd
10	M2	358	Kingston Ave, Hope Valley
11	M2	967	Port Rd, Woodville
12	M2	1079	Clairville Rd, Newton
13	H1	196	Flaxmill Rd (Morton Rd) - next to inoperable V198
14	H1	198	Flaxmill Rd (Morton Rd) - next to inoperable V196
15	H1	427	Regency Rd, Kilkenny
16	H1	428	Regency Rd, Kilkenny
17	H1	437	Stafford Grove, Toorak Gardens
18	H1	565	Aldam Rd, Seaford Meadows

19	H1	638	Commercial Rd, Seaford
20	H1	667	Reynell Rd (Byards Rd)
21	H1	734	South Rd (north of Daws Rd) - over southern tunnel of T2D
22	H1	765	Heaslip Rd, Angle Vale
23	H1	800	KWS/Currie St
24	H1	871	Fullarton Rd, Dulwich
25	H1	963	Main North Rd (Stanbel Rd)
26	H1	965	Main North Rd, Brahma Lodge
27	H1	975	Frost Rd, Salisbury
28	M2	431	Frederick Rd (cnr Maramba Ave)
29	M2	453	Doradus Ave, Hope Valley
30	M2	516	Diment Rd (Bolivar Rd)

Appendix B – Cost estimate (bottom-up)

Transmission pressure valves

Labour					
Expenditure year	**Category**	**Description**	**No of items**	**Unit Rate ($/unit)**	**Total cost**
	Labour - Contractor	Main contractor - TP Valves	11	[redacted]	[redacted]
	Labour - Contractor	Third party specialist contractors - TP Valves	11	[redacted]	[redacted]
	Labour - Internal	Commissioning/ Assembly / Site works - TP Valves	11	[redacted]	[redacted]
	Labour - Internal	Project Management and engineering - TP Valves	11	[redacted]	[redacted]
			TOTAL LABOUR COST $	[redacted]	[redacted]
Materials					
Expenditure tear	**Category**	**Description**	**No of items**	[redacted]	[redacted]
	Material - Pipe	Pipes and flanges - TP valves	11	[redacted]	[redacted]
	Material - Valves	Tees and valves - TP Valves	11	[redacted]	[redacted]
	Material - Fittings	Miscellaneous fittings - TP Valves	11	[redacted]	[redacted]
			TOTAL MATERIAL COST $	[redacted]	[redacted]
Total transmission valves				[redacted]	[redacted]

Distribution pressure valves

Labour					
Expenditure year	**Category**	**Description**	**No of items**	**Unit Rate ($/unit)**	**Total cost**
	Labour - Contractor	Main contractor - DP valves	31	[redacted]	[redacted]
	Labour - Contractor	Third party specialist contractors - DP valves	31	[redacted]	[redacted]
	Labour - Internal	Project management and Engineering - DP valves	31	[redacted]	[redacted]
			TOTAL LABOUR COST $	[redacted]	[redacted]
Materials					
Expenditure year	**Category**	**Description**	**No of items**	[redacted]	[redacted]
	Material - Pipe	Pipes and flanges - DP valves	31	[redacted]	[redacted]
	Material - Valves	Tees and Valves - DP valves	31	[redacted]	[redacted]
	Material - Fittings	Miscellaneous fittings - DP valves	31	[redacted]	[redacted]
			TOTAL MATERIAL COST $	[redacted]	[redacted]
Total distribution valves				[redacted]	[redacted]

Appendix C – Comparison of risk assessments for each option

Untreated risk	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Remote	Occasional	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Significant	Minimal	Major	Minimal	Significant	Significant	Minor	
Risk Level	Moderate	Negligible	High	Negligible	Moderate	Moderate	Low	

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Significant	Minimal	Major	Minimal	Minor	Minor	Minor	
Risk Level	Moderate	Negligible	High	Negligible	Low	Low	Low	

Option 2	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Moderate ALARP
Consequence	Significant	Minimal	Major	Minimal	Minor	Minor	Minor	
Risk Level	Low	Negligible	Moderate	Negligible	Negligible	Negligible	Negligible	

Option 3	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Moderate (ALARP)
Consequence	Significant	Minimal	Major	Minimal	Minor	Minor	Minor	
Risk Level	Low	Negligible	Moderate	Negligible	Negligible	Negligible	Negligible	

SA204 – M42 bridge and pipeline structure

1.1 Project approvals

Table 0.1: Business case SA204 – Project approvals

Prepared by	Matthew Haynes – AA Project Engineer
Technical SME	Hossein Ghanbari Adivi – Pipeline Integrity Engineer
Reviewed by	Alan Creffield – Manager, Integrity
Approved by	Michael Iapichello – Head of Engineering and Planning

1.2 Project overview

Table 0.2: Business case SA204 – Project details

Description of the problem / opportunity	The M42 pipeline operates at 1,750 kPa and passes through the inner metropolitan area. The pipeline was constructed with an original design life of 50 years and is now entering its 61st year of operation. The outperformance of its predicted asset life has been due to prudent asset management and life extension strategies. The predominantly buried pipeline is constructed from 6.35mm WT API 5L Grade B steel and coated with a coal tar enamel, however where the pipeline crosses the Torrens River, the pipeline comes above ground and is coated with a UV stabilised paint. The unique situation with this section is that AGN owns both the structure and the pipeline, whereas for the remainder of the network the bridge structures are owned and maintained by third parties and AGN's pipeline asset is attached to, or within, the bridge itself. The steel c-section making up the pipeline support is welded to the pipeline, thereby making the bridge and pipeline one integrated structure. The integrated structure, built in 1968, was not designed with future external or internal inspections in mind, nor were all the future industrial, commercial and residential offtakes and demands known at that time. In 2023, a visual inspection of two accessible supports near each riverbank reported surface corrosion at the crevice of the steel pipeline and support structure weld. This has resulted in significant challenges for the M42 integrated bridge and pipeline support structure that needs to be addressed: • The M42 pipeline, including the integrated river crossing structure, is currently deemed unpiggable with today's technology, and therefore the condition cannot be ascertained through in-line-inspection • There are not any established structures around the bridge that enable a safe external inspection to be conducted on the structure • There is very limited information on the design basis of the original bridge/support structure that can be used to make informed asset management decisions This means that AGN is unable to fulfil its obligations under AS/NZS2885.3. In order to meet our obligations under AS/NZS2885.3, we will undertake an external examination of the pipeline using specialist contractors and systems of work that will allow the development a comprehensive front end engineering design (FEED) study to inform future asset management strategies, and for the asset replacement or life extension strategies we may adopt. This business case outlines the various solutions, timings and their relative costs and benefits.

A further challenge is that since construction, the pipeline has become critical to the security of supply to customers in the area. As a result the bridge cannot be isolated without causing a significant loss of supply event. Reactive isolation of this exposed pipeline section will interrupt supply to at least 2,000 domestic customers as well as a large industrial and commercial (I&C) demand customer ([redacted] The proactive resolution of the immediate security of supply issue is discussed in business case SA203: Isolation valves.

Untreated risk

As per risk matrix = Moderate

Options considered

- **Option 1** - Manage the bridge and pipeline structure reactively (no upfront capex)
- **Option 2** – Develop FEED study for the bridge and pipeline structure ($0.4 million)
- **Option 3** – Replace the bridge and pipeline structure with a new crossing ($2.3 million)

Proposed solution

Option 2 is the proposed solution as it supports a consistent approach to supply and pipeline integrity. It maintains compliance with industry standard practice for the inspection of the crossing section and supports and reduces the risk to low for a reasonable level of investment.

This involves performing an outsourced integrity inspection of the whole length of the exposed pipeline section and support structure. Note this business case proposes costs for the FEED study only. If immediate replacement is required funds will be redirected from the capital portfolio, however in this instance it is not deemed prudent to provide for further investment until the FEED study is complete.

Option 1 does not mitigate the high operational risk associated with the potential for service shutdown to a significant number of customers in an emergency.

Option 3 will mitigate the operational risk, but this will be at a significantly higher cost per customer mitigated than Option 2.

Estimated cost

The forecast direct cost (excluding overhead) during the next five-year period (July 2026 to June 2031) is $0.4 million.

$'000 Jan 2025	26/27	27/28	28/29	29/30	30/31	Total
FEED study	376	-	-	-	-	**376**

Basis of costs

All costs in this business case are expressed in real unescalated dollars at January 2025 unless otherwise stated.

Treated risk

As per risk matrix = Low

Alignment to our vision

This project aligns with the *Customer Focussed* aspect of our vision. It delivers for customers by ensuring acceptable levels of security and reliability of gas supply.

Consistency with the National Gas Rules (NGR)

This project complies with the following National Gas Rules (NGR):

NGR 79(1) – The proposed solution is consistent with good industry practice, several practicable options have been considered, and market rates have been tested to achieve the lowest sustainable cost of providing this service.

NGR 79(2) – The proposed capex is justifiable under NGR 79(2)(c)(ii), as it is necessary to maintain the integrity of services.

NGR 74 – The forecast costs for the proposed FEED study are market tested and reflect estimates from potential vendors. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.

Stakeholder engagement

Feedback from stakeholders is built into our asset management considerations and is an important input when developing and reviewing our expenditure programs. Our customers have told us their top three priorities are price/affordability, reliability of supply, and maintaining public safety. They also told us they expect us to deliver a high level of public safety and are satisfied that this is current practice.

Performing an outsourced integrity inspection of the whole length of the exposed pipeline section will assist us to determine the best course of treatment to maintain

	reliability of supply. It will provide sufficient data on which to develop an asset strategy for the M42 bridge structure moving forward.
Other relevant documents	• Attachment 9.3: Asset Management Plan • Attachment 9.6: Procurement Policy & Procedure • Attachment 9.10: Unit Rates Report • Attachment 9.11: Risk Management Framework • Business case SA203: Isolation valves • AS/NZS 2885 Australian Standard for Pipelines - Gas & Liquid Petroleum

1.3 Background

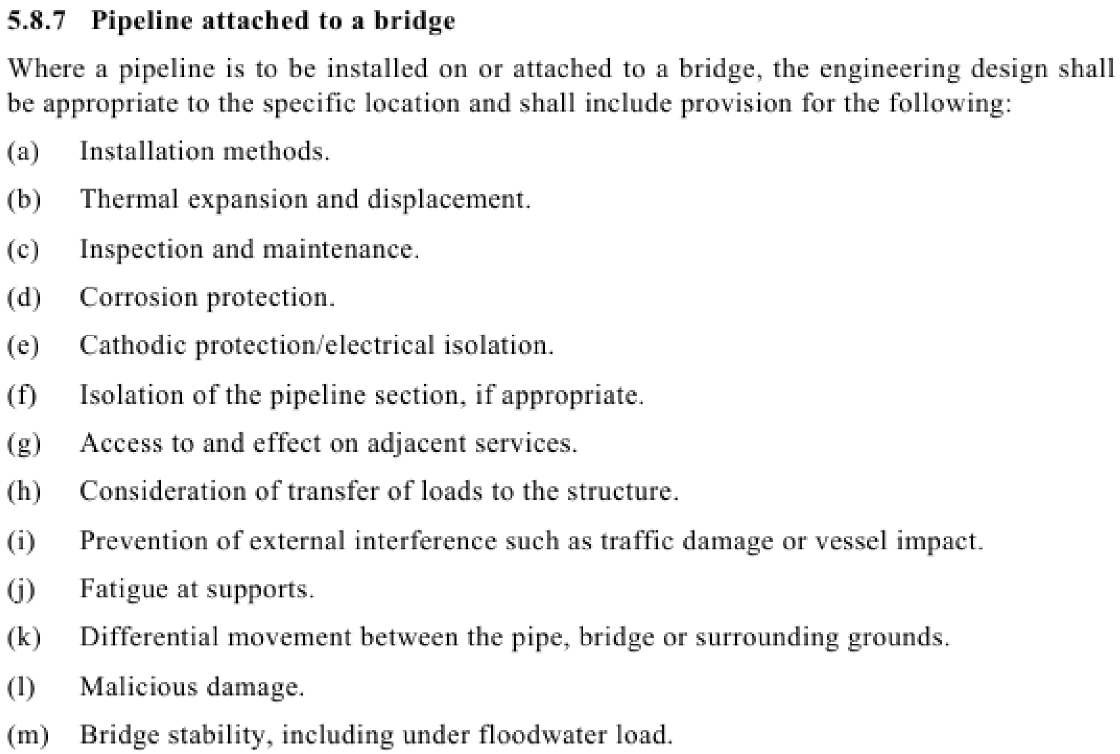
The M42 transmission pressure (TP) pipeline is one of the most important in our network, supplying gas to thousands of customers in the Adelaide metropolitan area. The predominantly buried pipeline is coated with a coal tar enamel, however where the pipeline crosses the Torrens River the pipeline comes above ground and is coated with a UV stabilised paint.

At the Torrens River crossing, the M42 pipeline is welded to a steel support frame that forms a bridge. Unlike all other river crossings, AGN owns both the pipeline and the bridge, and is responsible for the maintenance of both. The characteristics of this river crossing structure means that this section of pipeline is extremely difficult to inspect, as there are no surrounding structures that would allow personnel to safely inspect the pipe or the bridge structure for corrosion. This section of pipeline is also not piggable with current in line inspection (ILI) technology. Our records indicate there have been no inspections of the pipeline, crossing structure and pipe supports since construction in 1968.

Figure 0.1: Torrens River exposed pipeline and crossing structure

The inability to safely inspect the bridge structure and this section of pipeline poses two significant problems. Firstly, we do not have clear data on the extent of corrosion on the structure or this section of pipeline and therefore cannot confirm its ongoing integrity. Secondly, section 5.8.7 of AS2885.3 specifies that there must be adequate provision for ongoing inspection and maintenance of pipelines attached to a bridge. We are therefore currently non-compliant with this standard.

Figure 0.2: Extract from AS2885.3



5.8.7 Pipeline attached to a bridge

Where a pipeline is to be installed on or attached to a bridge, the engineering design shall be appropriate to the specific location and shall include provision for the following:

(a) Installation methods.
(b) Thermal expansion and displacement.
(c) Inspection and maintenance.
(d) Corrosion protection.
(e) Cathodic protection/electrical isolation.
(f) Isolation of the pipeline section, if appropriate.
(g) Access to and effect on adjacent services.
(h) Consideration of transfer of loads to the structure.
(i) Prevention of external interference such as traffic damage or vessel impact.
(j) Fatigue at supports.
(k) Differential movement between the pipe, bridge or surrounding grounds.
(l) Malicious damage.
(m) Bridge stability, including under floodwater load.

The complicating factor with this section of pipeline is the relationship between the bridge structure and the pipe itself. Both are integrated and are essentially the same structure. This means that even if the pipeline itself is in good condition, if the bridge fails then it may break the pipe, and vice versa. It is therefore important we have sufficient information on the integrity of the pipe and the bridge.

It is the bridge structure that is posing the biggest concern. A visual inspection of the bridge structure reported surface corrosion at the two accessible supports near each riverbank (see Figure 0.3).

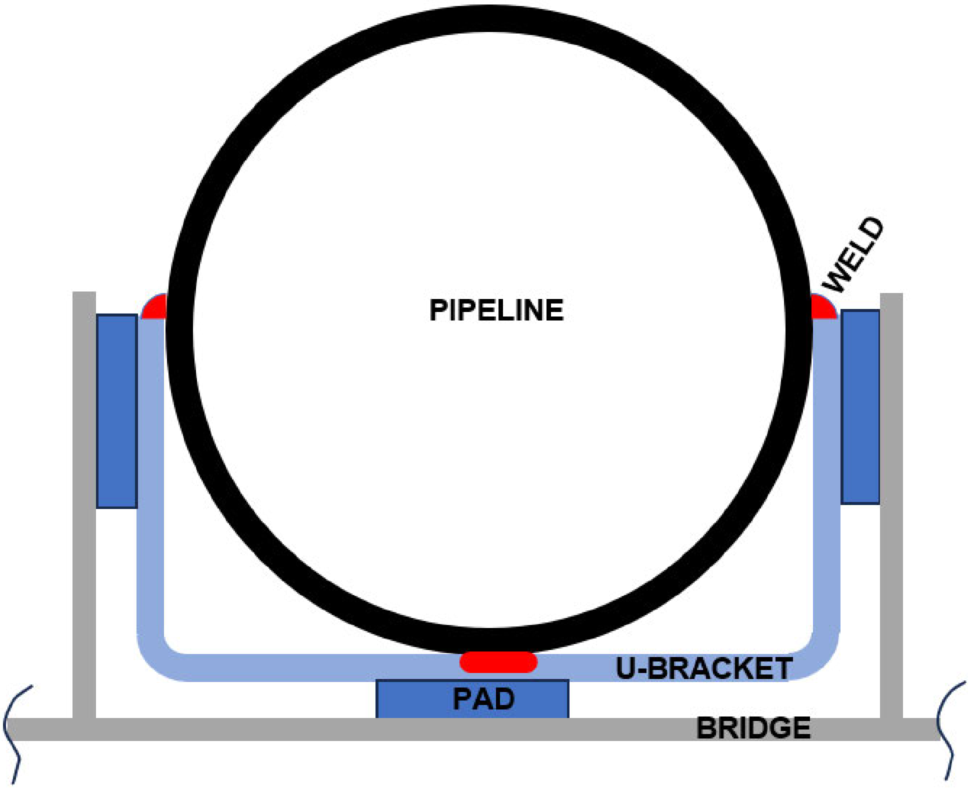
Figure 0.3: Corrosion at existing support structures

The two supports inspected where removed and replaced with supports compliant with current Australian Standards (see Figure 0.4).

Figure 0.4: New pipeline supports

It was also noted during the support replacement that the steel c-section making up the pipeline support was welded to the pipeline. On further inspection we found all the pipeline supports were constructed in this manner and there are no design or construction records available for these supports.

Figure 0.5: Sketch of current c-channel pipeline support and weld locations



Given the prevalence of corrosion on the supports we could inspect, it is reasonable to assume there may be similar levels of corrosion on the supports that we cannot currently access. The poor design records for the 60-year-old structure means we do not have data on the performance and potential failure modes for the bridge and cannot therefore verify the structural integrity of the bridge or the pipe attached to it.

To mitigate the risk a full FEED study is required so we can develop long term asset management strategies and investment timing for the pipeline bridge structure. As part of the FEED study a full-length external inspection is required. These measures will enable AGN to comply with its integrity obligations under AS/NZS 2885.3 and develop an adequate solution to reduce the risk to low or as low as reasonably practicable (ALARP).

1.4 Risk assessment

Risk management is a constant cycle of identification, analysis, treatment, monitoring, reporting and then back to identification. When considering risk and determining the appropriate mitigation activities, we seek to balance the risk outcome with our delivery capabilities and cost implications. Consistent with stakeholder expectations, safety and reliability of supply are our highest priorities.

Our risk assessment approach focuses on understanding the potential severity of failure events associated with each asset and the likelihood that the event will occur. Based on these two key inputs, the risk assessment and derived risk rating then guides the actions required to reduce or manage the risk to an acceptable level.

Figure 0.6: Risk management principles

Our risk management framework is based on:

- AS/NZS ISO 31000 Risk Management – Principles and Guidelines
- AS 2885 Pipelines-Gas and Liquid Petroleum
- AS/NZS 4645 Gas Distribution Network Management

The *Gas Act 1997* and *Gas Regulations 2012*, through their incorporation of AS/NZS 4645 and the *Work Health and Safety Act 2012*, place a regulatory obligation and requirement on AGN to reduce risks rated high or extreme to low or negligible as soon as possible (immediately if extreme). If it is not possible to reduce the risk to low or negligible, then we must reduce the risk to as low as reasonably practicable (ALARP).

When assessing risk for the purpose of investment decisions, rather than analysing all conceivable risks associated with an asset, we look at a credible, primary risk event to test the level of investment required. Where that credible risk event has an overall risk rating of moderate or higher, we will undertake investment to reduce the risk.

Seven consequence categories are considered for each type of risk:

22. **Health & safety** – Injuries or illness of a temporary or permanent nature, or death, to employees and contractors or members of the public
23. **Environment** (including heritage) – Impact on the surroundings in which the asset operates, including natural, built and Aboriginal cultural heritage, soil, water, vegetation, fauna, air and their interrelationships
24. **Operational capability** – Disruption in the daily operations and/or the provision of services/supply, impacting customers
25. **People** – Impact on engagement, capability or size of our workforce
26. **Compliance** – The impact from non-compliance with operating licences, legal, regulatory, contractual obligations, debt financing covenants or reporting / disclosure requirements
27. **Reputation & customer** – Impact on stakeholders' opinion of AGN, including personnel, customers, investors, security holders, regulators and the community

28. **Financial** – Financial impact on AGN, measured on a cumulative basis

The primary risk event being assessed is that corrosion causes the bridge structure to fail and the pipeline to rupture, impacting supply to more than 2,000 customers, including one demand customer (using >10 TJ p.a.).

The untreated risk[5] rating is presented in Table 0.3.

Table 0.3: Risk rating – untreated risk

Untreated risk	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Unlikely	Moderate
Consequence	Major	Minor	Major	Minimal	Significant	Significant	Minor	
Risk Level	Moderate	Negligible	Moderate	Negligible	Low	Low	Low	

We consider the current (effectively untreated) risk is moderate. This is because the level of corrosion is currently unknown and it is feasible that if corrosion is left unchecked, the bridge structure may fail within in the next 10-20 years, potentially sooner. If the bridge does fail, it will impact thousands of customers' supply, including one major demand customer, [redacted] Loss of containment would also create a moderate health and safety risk.

1.5 Options considered

The options considered are:

- **Option 1** – Manage the bridge and pipeline structure reactively
- **Option 2** – Develop FEED study for the bridge and pipeline structure and invest accordingly
- **Option 3** – Replace the bridge and pipeline structure with a new crossing

1.5.1 Option 1 – Manage the bridge and pipeline structure reactively

Under Option 1 we would not complete any additional integrity inspections on the exposed pipeline or support structure, nor develop remediation strategies. We would continue with our current pipeline inspections at the far ends, which therefore does not include inspection of the exposed pipeline or pipeline support structure.

1.5.1.0 Advantages and disadvantages

The advantage of this approach is that it requires no change to current practices and avoids the cost of installing temporary structures to allow inspection and a thorough FEED study.

The disadvantage of Option 1 is that it leaves the corrosion levels unchecked and therefore does little or nothing to address the risk of integrity failure. The bridge structure has been in-situ for more than 60 years and there are signs of corrosion on some sections. It is possible corrosion could be further advanced that we think, and it would therefore be imprudent (and arguably reckless) to assume the structure will remain intact for several more decades without inspecting it.

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[5] Untreated risk is the risk level assuming there are no risk controls currently in place. Also known as the 'absolute risk'.

1.5.1.1 Cost assessment

There would be no additional upfront capital costs with this option. The current planned maintenance program would continue, and any extra cost would be for repairs or emergencies when pipeline or support structure failures occur.

1.5.1.2 Risk assessment

Option 1 would see us continue with a reactive only approach. While this may provide slightly greater risk controls than an entirely untreated risk, it does little to mitigate the likelihood of structural failure and subsequent supply impacts. We therefore consider Option 1 results in an overall risk rating of moderate.

Table 0.4: Risk rating – Option 1

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Unlikely	Moderate
Consequence	Major	Minor	Major	Minimal	Significant	Significant	Minor	
Risk Level	Moderate	Negligible	Moderate	Negligible	Low	Low	Low	

Failing to address a moderate risk rating where there is a practicable treatment available is not consistent with the requirements of our risk management framework and does not reflect the actions of a prudent asset manager.

1.5.1.3 Alignment with vision objectives

Table 0.5 shows how Option 1 aligns with our vision objectives.

Table 0.5: Alignment with vision – Option 1

Vision objective	Alignment
Customer Focussed – Public Safety	N
Customer Focussed – Customer Experience	-
Customer Focussed – Cost Efficient	N
A Leading Employer – Health and Safety	-
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	-
Operational Excellence – Benchmark Performance	N
Operational Excellence – Reliability	-
Sustainable Communities – Enabling Net Zero	-
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	-

Option 1 would not align with our objective of being *Customer Focussed*, as it would not address the integrity and supply risk that could result in a loss of supply to a loss of containment.

This option also does not align with our objectives of *Operational Excellence*, as this option is inconsistent with AS/NZS 2885.3 and prevailing industry standards which require us to understand the asset details and current integrity through inspections.

1.5.2 Option 2 – Develop FEED study for the bridge and pipeline structure and invest accordingly

Under this option we will develop a detailed FEED study based on a comprehensive inspection, that will guide us to future investments and extend and protect the primary asset life.

The FEED study will help determine whether we should replace, repair or modify the existing asset and the most appropriate timeframe. Under this option we have assumed that the works required to extend the asset life will be outside of the upcoming regulatory period. However, in the unlikely event the FEED study provides evidence that immediate action is required to replace or reinforce the bridge structure, we will undertake the works during the upcoming AA period.

The development of a FEED study will involve engineering resources and specialist contractors to inspect the whole length of the exposed pipeline for structural and corrosion defects.

1.5.2.0 Advantages and disadvantages

The advantage of this approach is that it will give us a thorough assessment of corrosion on the pipeline and bridge structure and allow us to develop an appropriate asset management strategy. It will also enable us to demonstrate compliance with AS/NZ 2885.3.

The disadvantage of this approach is that it will require specialist resources and contractors to conduct the inspection. The bridge structure was not designed with future inspection requirements in mind, and therefore there are no adjacent structures or anchoring/access points that would allow an inspection to be conducted easily and safely. The inspection will therefore require temporary scaffolding and safety equipment, adding to the cost of the FEED. There is also the remote possibility that inspection shows bridge failure is imminent, which would result in the need for costly repair/replacement during the next AA period.

1.5.2.1 Cost assessment

The estimated cost of Option 2 is $0.4 million. This covers the cost of the FEED including the inspection. It also includes a provision for minor works and remediation.

The FEED costs have been estimated using quotes from potential vendors and an assessment of historical inspection costs where specialist equipment/contractors have been required.

Table 0.6: Cost estimate – Option 2, $'000 January 2025

	26/27	27/28	28/29	29/30	30/31	Total
FEED study	376	0	0	0	0	**376**

1.5.2.2 Risk assessment

This option reduces the risk associated with bridge failure from moderate to low. Though the FEED itself won't directly address the corrosion, the data it provides will allow us to implement appropriate risk controls that will reduce the likelihood of the bridge structure failing from remote to rare.

Table 0.6: Risk rating – Option 2

Option 2	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Rare	Rare	Rare	Rare	Rare	Rare	Rare	Low
Consequence	Major	Minor	Major	Minimal	Significant	Significant	Minor	
Risk Level	Low	Negligible	Low	Negligible	Negligible	Negligible	Negligible	

It is important to note that the above risk assessment relates only to the bridge structure failing. There is an inherent risk associated with all high-pressure gas pipelines; therefore the risk associated with loss of containment along the M42 pipeline itself will always be moderate/ALARP. However, the risk of the M42 failing due to the bridge structure failing would be reduced to low.

1.5.2.3 Alignment with vision objectives

Table 0.7 shows how Option 2 aligns with our vision objectives.

Table 0.7: Alignment with vision – Option 2

Vision objective	Alignment
Customer Focussed – Public Safety	Y
Customer Focussed – Customer Experience	-
Customer Focussed – Cost Efficient	Y
A Leading Employer – Health and Safety	-
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	-
Operational Excellence – Benchmark Performance	-
Operational Excellence – Reliability	Y
Sustainable Communities – Enabling Net Zero	-
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	-

Option 2 aligns with our objectives of *Customer Focussed*, as it addresses the unknown integrity risk and security of supply risks associated with the exposed pipeline section and pipeline crossing support structure.

Option 2 also aligns with our objectives of *Operational Excellence*, as this option would make us compliant with AS/NZS 2885.3 and prevailing industry standards through inspection.

1.5.3 Option 3 – Replace the bridge and pipeline structure with a new crossing

Under Option 3 we would not perform the integrity inspection. We would work under the assumption that as the bridge is already 10 years past its forecast design life and the best long-term solution is to replace the bridge with a modern equivalent.

Consideration would be given to replacing the bridge with a like for like structure, however industry good practice is to bore a new crossing beneath the Torrens River. The minimum bore radius for the required DN250 X42 pipe is estimated to be approximately 63 metres, which results in a forecast bore length of 200 metres.

1.5.3.0 Advantages and disadvantages

The advantage of this option is that it will eliminate the risk of bridge failure. This option would mitigate all the unknowns regarding the existing bridge structure without the need for further investigation or development of an asset management strategy. It will also allow us opportunity to reconfigure this part of the pipeline so that it is piggable, meaning we will also be compliant with AS/NZS 2885.

The disadvantage of this approach is the cost and disruption. The cost of boring a new river crossing is substantial, as well as the cost of gas stoppling and reconfiguring the pipework. The disruption to customers (including a major demand customer) while these works take place may also be significant, requiring carefully planned outage management.

1.5.3.1 Cost assessment

The estimated cost of this option is $2.3 million.

Table 0.8: Cost estimate – Option 3, $'000 January 2025

	26/27	27/28	28/29	29/30	30/31	Total
Engineering design	200	200	-	-	-	**400**
Construction	-	859	1,058	-	-	**1,917**
Total	**200**	**1,059**	**1,058**	**-**	**-**	**2,317**

1.5.3.2 Risk assessment

Option 3 provides the greatest risk mitigation, eliminating the risk of bridge failure. This results in an overall risk rating of negligible, as the likelihood and consequence of a bridge failure are reduced to their lowest levels (as the bridge is gone).

Table 0.9: Risk rating – Option 3

Option 3	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Rare	Rare	Rare	Rare	Rare	Rare	Rare	Negligible
Consequence	Minor	Minor	Minor	Minor	Minor	Minor	Minor	
Risk Level	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	

The risk outcome under Option 3 is best practice, as eliminating a risk is the best form of control. However, the costs are significantly higher than Option 2.

It should also be noted that this risk assessment is for the bridge failure only. The M42 pipeline will still traverse the river and will be operational, therefore there will always be an inherent risk with the pipeline itself. While we eliminate the risk of bridge failure causing loss of containment, we are not eliminating the potential for pipeline integrity issues in the future.

1.5.3.3 Alignment with vision objectives

Table 0.10 shows how Option 3 aligns with our vision objectives.

Table 0.10: Alignment with vision – Option 3

Vision objective	Alignment
Customer Focussed – Public Safety	Y
Customer Focussed – Customer Experience	-
Customer Focussed – Cost Efficient	N

Vision objective	Alignment
A Leading Employer – Health and Safety	-
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	-
Operational Excellence – Benchmark Performance	-
Operational Excellence – Reliability	Y
Sustainable Communities – Enabling Net Zero	-
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	-

Option 3 does not completely align with our objective of being *Customer Focussed*. While it addresses the unknown integrity risk and security of supply risks associated with pipeline and bridge it does so at a significantly higher cost than other options.

This option would align with *Operational Excellence*, as it would promote the ongoing integrity and reliability of this section of pipeline.

1.6 Summary of options assessment

Table 0.11 presents a summary of how each option compares in terms of the estimated cost, residual risk rating, and alignment with our objectives.

Table 0.11: Comparison of options

Option	Estimated cost	Treated residual risk rating	Alignment with vision objectives
Option 1: Do nothing	No upfront capex	Moderate	Does not align with *Customer Focussed* and does not reflect *Operational Excellence*
Option 2: FEED study	$0.4 million	Low	Aligns with *Customer Focussed* and reflects *Operational Excellence*
Option 3: New crossing	$2.3 million	Negligible	Aligns with *Customer Focussed* but does not reflect *Operational Excellence* due to the increased cost compared with Option 2

1.7 Recommended option

Option 2 is the proposed solution. This option involves the development of a FEED study, with the inclusion of an integrity inspection of the integrated and exposed transmission pipeline and pipeline support structure, with the development of repair and replacement strategies for long-term asset management.

This project will be delivered using a combination of internal and external resources. The project will be initiated internally by the asset manager. Design and installation will be completed by contractors. Contractors will be selected through a competitive tender process with quality assurance and project closure handled by internal resources.

1.7.1 Why is the recommended option prudent?

Option 2 is proposed because:

- It represents good engineering practice that will enable us to meet requirements of AS/NZ 2885.3
- It reduces this risk to an acceptable level (low) without complete replacement upfront, therefore a level of risk commensurate to the investment
- In the unlikely scenario that the FEED study requires that the bridge be immediately decommissioned we will review the entire portfolio to allow for the works to commence, however, we do not anticipate significant works to be required at this stage
- It is consistent with customer and stakeholder requirements and our vision objectives
- The delivery of the scope of works is achievable in the timeframe envisaged

1.7.2 Estimating efficient costs

The cost estimate for this project has been developed based on the following assumptions:

- The cost estimate is based on costing the activities that comprise the work breakdown structure
- The rates utilised in costing these activities are based on current vendor and contractor rates in 2024
- The scope and work breakdown structure are based on a cost verification
- The works will be completed by contractors with support from internal technicians and engineers
- Contractors will be selected through a competitive tender process
- Project delivery practices and controls such as advanced planning and scheduling of work are in place to effectively manage risk in delivery

1.7.3 Consistency with the National Gas Rules

In developing these forecasts, we have had regard to NGR 79 and 74. With regard to all projects, and as a prudent asset manager, we give careful consideration to whether capex is conforming from a number of perspectives before committing to capital investment.

NGR 79(1)

The proposed solution is prudent, efficient, consistent with accepted and good industry practice and will achieve the lowest sustainable cost of delivering pipeline services:

- **Prudent** – The expenditure is necessary in order to ensure that integrity and customer supply threats are mitigated practically. Failure to develop an adequate FEED study would mean that any integrity risk in the exposed pipeline section will go undetected until failure. Corrosion leading to asset failure and an uncontrolled gas leak would result in the loss of supply to customers in the area. The proposed expenditure is therefore consistent with that which would be incurred by a prudent service provider.

- **Efficient** – A FEED study that includes the inspection of the above ground pipeline section and support is the most practical and cost-effective option. To simply replace the structure without exploring the option of extending the life of the existing asset would not be efficient. The expenditure is therefore consistent with what a prudent service provider acting efficiently would incur.

- **Consistent with accepted and good industry practice** – Inspecting and maintaining above ground pipeline crossings is consistent with *AS 2885.3 Pipelines - Gas and Liquid Petroleum, Part 3: Pipeline Integrity Management* and *AS/NZ 4645 Distribution*. We consider reducing the number of impacted customers by reducing the risk to as low is consistent with good industry practice.

- **To achieve the lowest sustainable cost of delivering pipeline services** – We have selected the lowest sustainable cost option, balancing costs against the level of risk reduction that can be achieved. We therefore consider Option 2 represents the lowest sustainable cost of delivering pipeline services.

NGR 79(2)

The proposed capex is justifiable under 79(2)(c)(ii), as it is necessary to maintain the integrity of services. The proposed option will allow us to maintain a consistent approach to supply integrity across the entire network, by maintaining a risk consequence impact of low.

NGR 74

The forecast costs are based on the latest market rate testing and project options consider asset management requirements as per the Asset Management Strategy. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.

Appendix A Cost estimate

SA204 - M42 Bridge Inspection

Category	Description	No. Items / Metres	Unit Rate ($/unit)	Total ($)
Labour - Consultant	Stage 1 Fitness for Service	1	103,460	103,460
Labour - Consultant	Stage 2 Remediation Work	1	273,000	273,000
Total				**376,460**

Appendix B Comparison of risk assessments

Untreated risk	Health & Safety	Environment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Unlikely	Moderate
Consequence	Major	Minor	Major	Minimal	Significant	Significant	Minor	
Risk Level	Moderate	Negligible	Moderate	Negligible	Low	Low	Low	

Option 1	Health & Safety	Environment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Unlikely	Moderate
Consequence	Major	Minor	Major	Minimal	Significant	Significant	Minor	
Risk Level	Moderate	Negligible	Moderate	Negligible	Low	Low	Low	

Option 2	Health & Safety	Environment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Rare	Rare	Rare	Rare	Rare	Rare	Rare	Low
Consequence	Major	Minor	Major	Minimal	Significant	Significant	Minor	
Risk Level	Low	Negligible	Low	Negligible	Negligible	Negligible	Negligible	

Option 3	Health & Safety	Environment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Rare	Rare	Rare	Rare	Rare	Rare	Rare	Negligible
Consequence	Minor	Minor	Minor	Minor	Minor	Minor	Minor	
Risk Level	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	

SA205 – Pipeline modifications for inline inspections

1.1 Project approvals

Table 0.1: Business case SA205 – Project approvals

Prepared by	Greg Cowley – Senior Pipeline Engineer
Reviewed by	Alan Creffield – Manager Integrity
Approved by	Michael Iapichello – Head of Engineering and Planning Nick Kafamanis – Head of Capital Delivery

1.2 Project overview

Table 0.2: Business case SA205 – Project overview

Description of the problem / opportunity	The South Australia (SA) distribution network includes approximately 200 km of metropolitan transmission pressure (TP) pipelines, which deliver gas to over 485,000 customers. These pipelines all require regular inspection and maintenance to ensure they are kept safe and operational. Previously, direct current voltage gradient (DCVG) survey combined with inspection excavation (or 'dig ups') had been the main method used to monitor the integrity of most SA metropolitan TP pipelines. While this methodology provides useful information on pipeline condition, it does not provide a complete picture of internal and external pipeline corrosion. This is because these techniques don't find all pipeline anomalies that can lead to pipeline failure. Inline inspection (ILI, also known as pigging) is a method of inspection whereby an ILI tool (pig) is pushed through the pipeline, measuring pipe wall thickness, internal pipe dimensions, and detecting defects. ILI is complementary to DCVG and dig ups as it ensures there are no gaps in our understanding of pipeline condition, thereby reducing the potential frequency and significance of pipeline failure caused by unknown defects. Australian Standard (AS/NZ) 2885.3-2022 requires pipeline owners/operators to consider adopting ILI where practicable. Section 6.5.1 specifically requires: *Where a pipeline (or section of a pipeline) cannot be inspected by an in-line tool, an assessment shall be conducted to determine whether the pipeline needs to be modified to facilitate an inspection or whether an alternative strategy is necessary.* Consistent with this requirement and what is now considered good industry practice for distribution businesses as well as transmission businesses, we have commenced works to assess all non-piggable TP pipelines with a view to making them piggable, where economical to do so. This business case considers various options for the ongoing pipeline modification program, which has been successfully established during the current period. The program focuses on TP pipelines that operate with the gas distribution business, that have been identified as the most suitable and/or highest risk priority candidates in the network. These pipelines were nominated using an asset risk score, overlaid with ILI-suitability, customer impact, cost and deliverability factors.
Untreated risk	As per risk matrix = High
Options considered	• **Option 1** – Status quo: Do not assess or modify any more unpiggable pipelines (no upfront capex, but would increase SA201 capex significantly) • **Option 2** – Design-led: Conduct assessments and design works for our high and intermediate priority unpiggable pipelines prior to modification and pigging works ($8.4 million, and increase in SA201 capex moderately) • **Option 3** – Rolling deployment: Continue the pipeline modification program to deliver each campaign with a rolling approach ($34.9 million)

Proposed solution

Option 3 is the proposed solution. This option will allow us to:

- Modify and pig the Eastern Ring Main campaign (M101 and M143) which we are in the process of completing a front end engineering and design (FEED) study for in the current period
- Complete four more ILI campaigns (FEED study, modify and pig) covering the Flagstaff Hill, Western Corridor and Elizabeth campaigns and the Churchill Road pipeline
- Conduct a FEED study for the Port Adelaide campaign ahead of its delivery in the first year of the next AA period

This approach allows us to undertake an assessment of each of our TP pipelines to understand the work required to facilitate ILI as required under AS 2885.3. We have prioritised the program of work in accordance with risk and suitability considerations, and designed 'ILI campaigns' which consider combining modification and pigging scopes to ensure efficient delivery. This option is consistent with standard industry practice.

The delivery of the program of work on a rolling basis is the most efficient option, as it will maintain a relatively smooth pipeline of work for our design and delivery teams. It will also allow us to complete the program of work in a reasonable timeframe, while considering the impact on prices.

Option 1 is non-compliant with the requirements of AS2885.3 and is not in accordance with standard industry practice and would result in escalating risks and lead to us replacing our TP pipelines earlier than if we adopt ILI.

Option 2 would identify the required works to make our TP pipelines piggable, but would not reduce risk during the period, and could result in re-work if the time between the design and execution works were significant.

Estimated cost

The forecast direct cost (excluding overhead) during the next period (July 2026 to June 2031) is $34.9 million.

$'000 Jan 2025	26/27	27/28	28/29	29/30	30/31	Total
Design, modification and pigging of TP pipelines	7,123	7,486	6,879	6,981	6,408	**34,877**

Basis of costs

All costs in this business case are expressed in real unescalated dollars at January 2025 unless otherwise stated.

Treated risk

As per risk matrix = Moderate

Alignment to our vision

This project aligns with the *Customer Focused* aspect of our vision. It delivers for customers by mitigating the safety and supply risks associated with undetected corrosion of our TP pipelines which has the potential to lead to a failure. It will enable us to develop a targeted program to address areas of corrosion, dents and gouges and apply a tailored correction/maintenance program resulting in a more efficient, more proactively managed and safer network.

This project also aligns with the *Operational Excellence* pillar of our vision. Enabling ILI will allow us to extend the life of our TP assets beyond the technical design life of 50-80 years thereby avoiding costly investment in the replacement of our TP network. The optimisation of modification campaigns and rolling delivery allows us to complete the program in the most timely and cost-efficient manner.

Consistency with the National Gas Rules (NGR)

This project complies with the following National Gas Rules (NGR):

NGR 79(1) – The proposed solution is consistent with good industry practice, several practicable options have been considered, and market rates have been tested to achieve the lowest sustainable cost of providing this service.

NGR 79(2) – The proposed capex is justifiable under NGR 79(2)(c)(i) and (ii), as it is necessary to maintain the safety and integrity of services.

NGR 74 – The forecast costs are based on the latest market rate testing and project options consider the asset management requirements as per the Asset Management Strategy. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances

Stakeholder engagement	Our customers have told us their top three priorities are price/affordability, reliability of supply, and maintaining public safety. They acknowledge that corrosion is an inherent risk for steel assets and that an ongoing program to mitigate this risk is necessary. The proposed TP pipeline modification program is consistent with recent practice and the practices of other gas distribution operators. Stakeholders have raised no concerns with the proposed program for the next period. Undertaking the proposed program will help maintain reliability of supply at the lowest sustainable cost, minimising the impact on customers' gas bills. We therefore consider the program is aligned with stakeholder expectations.
Other relevant documents	• Attachment 9.3: Asset Management Plan • Attachment 9.6: Procurement Policy & Procedure • Attachment 9.10: Unit Rates Report • Attachment 9.11: Risk Management Framework • AS/NZS 2885 Australian Standard for Pipelines - Gas & Liquid Petroleum • APA Technical Policy – In-line Inspection Transmission Pressure Pipelines • Business case SA201: Corrosion management of steel pipework • Distribution Mains & Services Integrity Program (DMSIP) • Pipeline Integrity Management Plan (PIMP) • Southern Adelaide TP Pipelines SMS Report

1.3 Background

The SA natural gas distribution networks include 200 km of metropolitan steel TP pipelines and 1,600 km of steel distribution pressure (DP) pipelines, which deliver gas to over 485,000 customers.

The map at Figure 0.2 shows the full TP pipeline network.

The greatest risk associated with these TP pipelines is corrosion, which can weaken the pipe wall and cause an integrity failure. Integrity management of steel pipework is a mature asset management field where good practice includes the following:

- Apply a good quality appropriate coating, suitable to the service environment using competent application personnel
- Where pipework is submersed or buried, apply effective cathodic protection
- Inspect the coating and cathodic protection systems at prudent intervals based on service environment, coating type, historical evidence and accessibility / available inspection techniques
- Take action to remediate defects found during inspections in a timely manner relevant to the scope and severity of the defect

Relevant to this program of work is the inspection of the condition of our TP pipelines.

We have a number of methods of inspecting the condition of our TP pipelines, however, ILI or pigging is industry standard practice where possible. This is reflected in the recent updates to Australian Standard AS2885.3-2022. Clause 6.5.1 states:

> *Periodic inspections of the pipe wall shall be carried out to determine whether preventative maintenance controls have been effective. The frequency of inspection shall be determined and detailed within the PIMP.*

> *Where a pipeline (or section of a pipeline) cannot be inspected by an in-line inspection tool, an assessment shall be conducted to determine whether the pipeline needs to be modified to facilitate an inspection or whether an alternative strategy is necessary. The limitations of any alternative strategy shall be assessed in the context of the specific pipeline system and documented in the AGN SA TP Network- Pipeline Integrity Management Plan - 420-PL-L-0001.*

ILI allows the asset owner/operator to make informed decisions about ongoing pipeline management, including whether it is safe to extend (or continue to extend) use of the pipeline beyond its technical design life.[6]

ILI is the best available inspection method that is able to provide the most comprehensive picture of asset condition. It allows:

- The asset manager to safely extend the life of the asset where the inspection shows the pipeline to be in good or serviceable condition, avoiding costly complete replacement by only replacing or repairing the corroded sections of a pipeline
- More efficient ongoing management of the pipeline with information on the location of defects meaning dig ups, repairs and replacements can be targeted and scheduled in an economically efficient manner
- Information on the environmental conditions and contributing factors to corrosion/defects at those locations to be analysed, and lessons learnt to be applied to other pipelines with similar characteristics

ILI is considered standard industry practice. All our new TP pipelines with a diameter greater than or equal to DN150 are now built to accommodate pigging, and most distribution other network owners such as ATCO and Jemena also have ILI conversion programs to modify older, unpiggable pipelines, which have been approved by the Australian Energy Regulator (AER)[7] and the AER's technical consultants[8].

Issues that restrict ILI include absence of pig bars on branch tees, short radius and back-to-back bends, reduced bore valves, plug valves and no provision for connection of pig launchers/receivers.

Figure 0.1: Example of a siphon that would protrude into the main and not allow an inline inspection tool to pass

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[6] The SA network of TP pipelines has a technical design life of around 40 years. Transmission pressure pipelines are required to undergo fitness for purpose assessments at no more than 10-year intervals which is an assessment of the safety and suitability of the pipeline for continued use.

[7] AER, *November 2019, Draft Decision, Jemena Gas Networks (NSW) Ltd Access Arrangement 2020 to 2025, Attachment 5 Capital expenditure*, page 5-34.

[8] Zincara, 2019, *Access Arrangement 2019 JGN Capital Expenditure Review, prepared for the AER,* page 75.

Modifications to make an existing pipeline piggable include (at a minimum):

- Installation of pig launchers and receivers
- Replacement of tight radius bends with swept bends to permit a pig to pass
- Removal of reduced bore valves
- Removal of obstructions that prevent pig passage (e.g. syphon sucker pipes)
- Valve configuration at each end of the pipeline to allow a pig launcher and receiver

In the current period, we commenced our pipeline modification program, assessing three sections of our TP network and modifying two of these. The M12 and M42 were selected as they are over 55 years old, and are the longest and most complex. The work completed in the current period is as follows:

- The 56-year-old 13.7 km section of the M12 from Waterloo Corner to Gulfview Heights was assessed, has been modified and is now piggable. The first ILI run will be completed in 2025/26
- The 44-year-old 3.95 km M84 pipeline from Para Hills to Ingle Farm was made piggable, and will be pigged as part of the M12 campaign due to proximity and cost-effectiveness as part of an optimised program
- Our desktop review of the M42 showed this pipeline, while being high priority, would not currently be economic to modify. This is due to the varying diameters of the pipeline (DN200, DN250 and DN300) and number and location of three-way Williamson tees and offsets, plug valves and back-to-back elbows identified (as documented in the Southern Adelaide TP Pipelines SMS Report).

In an effort to improve compliance with AS/NZS 2885, we will continue the pipeline modification program in the next period. We have completed extensive risk assessment and prioritisation works to develop a pipeline modification plan for execution over the next 10 to 15 years.

There are 36 sections, or 146 km of TP pipeline that, based on the information available at the time of developing the plan, are not piggable but could reasonably and safely be made piggable (see Table 0.3). This assumption is based on current technology and needs to be continually assessed to enable ILI if it is economic to do so.

Table 0.3: TP pipelines required for assessment

No.	Name	Age	Length (km)	MAOP (kPa)	Diameter (mm)
M6	Churchill Road	56	3.36	1896	DN300
M7	Churchill Rd to Dry Creek	56	1.52	1896	DN400
M12	Gulfview Heights to Yatala Vale Lateral	56	7.60	1896	DN200
M22	Le Fevre Peninsula	55	5.01	1896	DN150 & DN200
M36	Seacombe Gardens to Flagstaff Hill	55	4.81	1896	DN200 & DN300
M37	Plympton to Edwardstown	52	2.46	1896	DN150
M38	G.M.H. Elizabeth	52	1.05	1896	DN200
M55	Elizabeth	30	4.05	1896	DN150
M55	Prospect to Brompton	56	3.35	1896	DN300 & DN475
M63	Port Pirie	49	5.23	1200	DN200
M68	Nuriootpa	48	0.54	1896	DN150
M71	Birkenhead	47	1.39	1896	DN200

No.	Name	Age	Length (km)	MAOP (kPa)	Diameter (mm)
M76	Flagstaff Hill - Blacks Rd	47	1.44	1896	DN200
M79	Glanville to Pt Adelaide	46	2.53	1896	DN200 & DN300
M80	Port Adelaide to Dry Creek	45	8.68	1896	DN300
M82	Elizabeth to Smithfield Plns, Coventry Rd	40	8.95	1896	DN150
M83	Pt Adelaide to Queenstown	44	1.64	1896	DN300
M90	Hendon to South Brighton	43	18.40	1896	DN300
M94	Dry Creek to Ingle Farm	43	6.10	1896	DN300
M101	Eastern Ring Main (Magill to North East Rd)	39	18.52	1896	DN300
M114	Southern Loop (O'Halloran Hill to Woodcroft)	29	8.30	1896	DN300
M117	Brompton to ACI (West Croydon)	23	3.09	1953	DN150
M124	Cormack Rd to Cooper's Brewery	22	3.93	1896	DN150
M126	SEAGAS Interconnection	21	0.54	1960	DN400
M131	Pt Noarlunga to Noarlunga Downs	16	0.95	1950	DN300
M143	Greenhill (Keswick to Linden Park)	12	7.19	1950	DN300
M148	West Terrace	12	2.38	1950	DN300
M149	Seacombe Gardens	12	0.79	1950	DN300
M150	Tanunda	12	0.69	1600	DN150
M169	Main South Rd, Old Noarlunga	7	1.59	1960	DN300
M172	Park Terrace	8	2.21	1960	DN300
M183	Hindmarsh	8	0.79	1960	DN150
M184	Eleanor Tce to Lagoon Rd, Murray Bridge	9	2.11	1800	DN150
M188	Dyson Rd	3	5.30	1960	DN300

We have considered the various characteristics of each of these sections of pipeline to develop a program of work that is underpinned by risk, optimised for deliverability, and is reasonably expected to be deliverable. Key considerations are:

- Pipeline age
- Coating defects and other signs of deterioration identified through DCVG and external corrosion direct assessments (ECDA or ‘dig ups’)
- Number of customers affected by a supply interruption
- Length of pipeline situated in high density or sensitive areas

This assessment has resulted in the following pipeline sections being prioritised for assessment and if economically feasible modification and pigging.

Table 0.4: High priority pipelines

No.	Name
M101	Eastern Ring Main (Magill to North East Rd)
M76	Flagstaff Hill - Blacks Rd
M36	Seacombe Gardens to Flagstaff Hill
M90	Hendon to South Brighton
M38	G.M.H. Elizabeth

No.	Name
M55	Elizabeth
M82	Elizabeth to Smithfield Plns, Coventry Rd
M6	Churchill Road
M94	Dry Creek to Ingle Farm
M12	Gulfview Heights to Yatala Vale Lateral

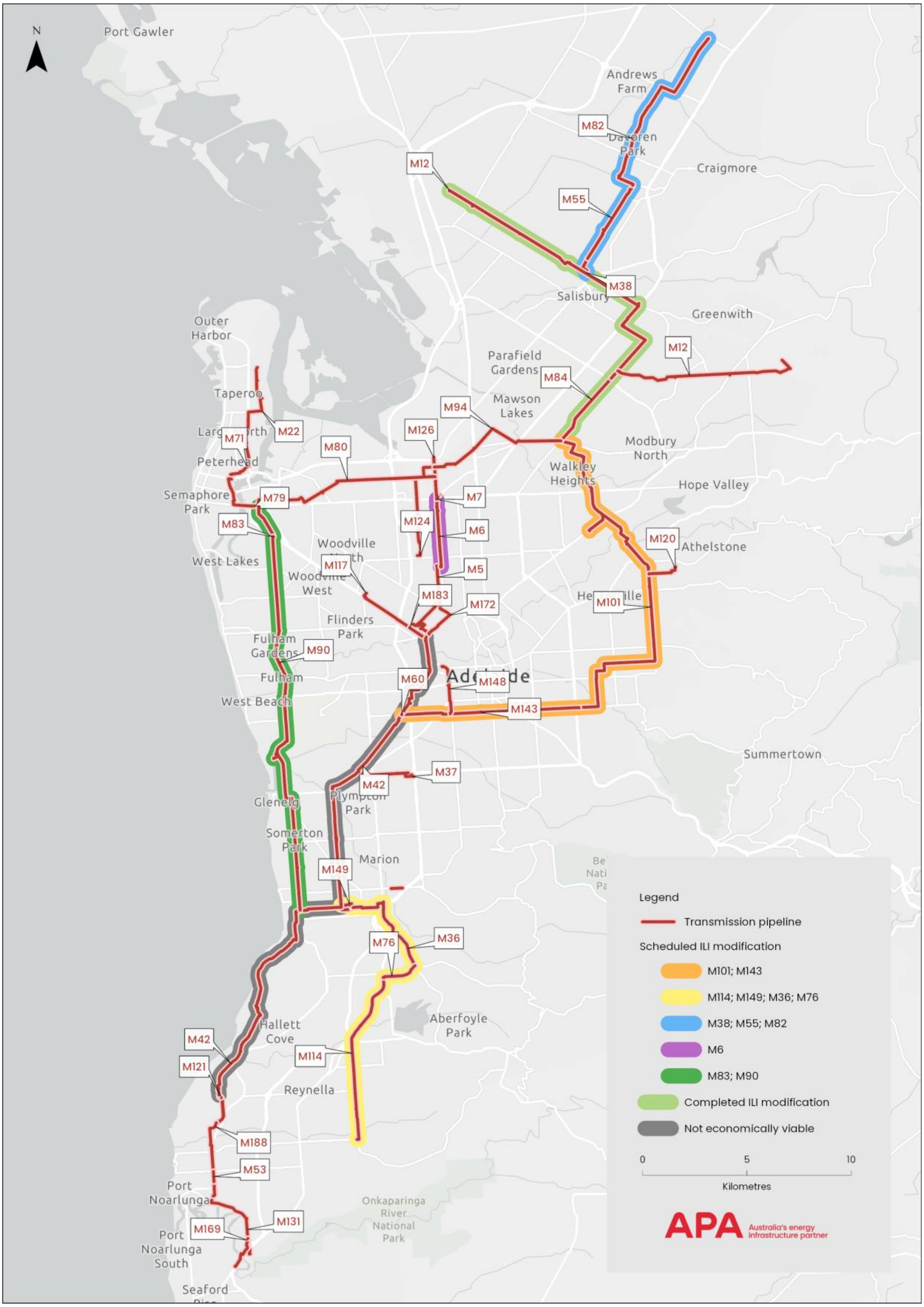
In developing an optimised program, we considered whether there were additional unpiggable pipelines that could cost-effectively be modified and pigged in conjunction with any of the above pipelines. This resulted in the proposed program shown in Table 0.5.

Table 0.5: Prioritised modification and pigging campaigns

Type	No.	Name
Eastern Ring Main		
Primary	M101	Eastern Ring Main (Magill to North East Rd)
Additional	M143	Greenhill (Keswick to Linden Park)
Flagstaff Hill		
Primary	M76	Flagstaff Hill - Blacks Rd
Primary	M36	Seacombe Gardens to Flagstaff Hill
Additional	M114	Southern Loop (O'Halloran Hill to Woodcroft)
Additional	M149	Seacombe Gardens
Western Corridor		
Primary	M90	Hendon to South Brighton
Additional	M83	Pt Adelaide to Queenstown
Elizabeth		
Primary	M38	G.M.H. Elizabeth
Primary	M55	Elizabeth
Primary	M82	Elizabeth to Smithfield Plns, Coventry Rd
Churchill Road		
Primary	M6	Churchill Road
Port Adelaide		
Primary	M94	Dry Creek to Ingle Farm
Additional	M80	Port Adelaide to Dry Creek
Eastern Lateral		
Primary	M12	Gulfview Heights to Yatala Vale Lateral

A geographical representation of each of these campaigns is shown in Figure 0.2.

Figure 0.2: Geographical representation of high priority campaigns



While each campaign will necessarily vary in the complexity and time required for the design and modification works, we won't have this level of detail until we have undertaken the piggability assessment.

We are currently in the process of assessing the Eastern Ring Main campaign, but will not have completed this until late 2025 or early 2026. For the purposes of this business case, we have therefore assumed an average planning and design period of 12 months, with the actual modification works and initial pig run the following 12 months. This means we expect each campaign, on average, to take two years to complete.

1.4 Risk assessment

Risk management is a constant cycle of identification, analysis, treatment, monitoring, reporting and then back to identification (as illustrated in Figure 0.10). When considering risk and determining the appropriate mitigation activities, we seek to balance the risk outcome with our delivery capabilities and cost implications. Consistent with stakeholder expectations, safety and reliability of supply are our highest priorities.

Our risk assessment approach focuses on understanding the potential severity of failure events associated with each asset and the likelihood that the event will occur. Based on these two key inputs, the risk assessment and derived risk rating then guides the actions required to reduce or manage the risk to an acceptable level.

Figure 0.3: Risk management principles

Our risk management framework is based on:

- AS/NZS ISO 31000 Risk Management – Principles and Guidelines
- AS 2885 Pipelines-Gas and Liquid Petroleum
- AS/NZS 4645 Gas Distribution Network Management

The *Gas Act 1997* and *Gas Regulations 2012*, through their incorporation of AS/NZS 4645 and the *Work Health and Safety Act 2012*, place a regulatory obligation and requirement on AGN to reduce risks rated high or extreme to low or negligible as soon as possible (immediately if extreme). If it is not possible to reduce the risk to low or negligible, then we must reduce the risk to as low as reasonably practicable (ALARP).

When assessing risk for the purpose of investment decisions, rather than analysing all conceivable risks associated with an asset, we look at a credible, primary risk event to test the level of investment required. Where that credible risk event results in a risk event rated moderate or higher, we will consider investment to reduce the risk.

Seven consequence categories are considered for each type of risk:

29. **Health & safety** – injuries or illness of a temporary or permanent nature, or death, to employees and contractors or members of the public
30. **Environment** (including heritage) – impact on the surroundings in which the asset operates, including natural, built and Aboriginal cultural heritage, soil, water, vegetation, fauna, air and their interrelationships
31. **Operational capability** – disruption in the daily operations and/or the provision of services/supply, impacting customers
32. **People** – impact on engagement, capability or size of our workforce

33. **Compliance** – the impact from non-compliance with operating licences, legal, regulatory, contractual obligations, debt financing covenants or reporting / disclosure requirements
34. **Reputation & customer** – impact on stakeholders' opinion of AGN, including personnel, customers, investors, security holders, regulators and the community
35. **Financial** – financial impact on AGN, measured on a cumulative basis

Our Risk Management Framework, including definitions, has been provided in Attachment 9.11.

The primary risk event associated with the identified unpiggable TP pipelines is that undetected corrosion, if left untreated, results in a significant uncontrolled gas escape in a densely populated area, resulting in fatality or permanent injury and/or loss of supply to >10,000 customers or a demand customer >1 TJ p.a.

Given the proximity of these TP pipelines to developed and densely populated areas, there is the potential for a safety or supply incident with major consequences in certain circumstances. If a fault in one or more major pipelines goes undetected, the costs involved in the replacement work leads to catastrophic financial consequences. This also leads to the potential for significant compliance and reputational consequences.

In the absence of this program of work, we would continue to conduct DCVG and dig ups as identified in business case SA201 which would deliver the risk rating presented in Table 0.9.

Table 0.6: Risk rating – Treated with DCVG and dig ups per business case SA201

Treated as SA201	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minimal	Major	Minor	Significant	Significant	Catastrophic	
Risk level	High	Negligible	High	Low	Moderate	Moderate	High	

1.5 Options considered

We have identified the following options to address the risks associated with undetected corrosion on our unpiggable TP pipelines:

- **Option 1** – Status quo: Do not assess or modify any more unpiggable pipelines
- **Option 2** – Design-led: Conduct assessments and design works for our high and intermediate priority unpiggable pipelines with subsequent modification and pigging works
- **Option 3** – Rolling deployment: Continue the pipeline modification program to deliver each campaign with a rolling delivery approach

We considered completing the design, modification and initial pig run for all of our seven highest priority campaigns within the next period, however, we do not consider this deliverable and have therefore discounted this as a viable option.

We also considered delivering the program as a set of discrete projects, starting the design for the next project only after the completion of the capital works for the previous project. However, we did not progress that option further as it would result in a less efficient design and delivery approach than Option 3.

Whereas at the start of the last regulatory period (2020) we were lacking in experience of delivering ILI modification and pigging programs, we now have an operational team that is proficient in delivery and is applying lessons learnt from the current period. The portfolio of projects can therefore now be optimised to use the resource base to achieve the best balance of risk reduction, resource utilisation and program flexibility.

A linear approach be unacceptable from a timeframe perspective. It would require a significant uplift in the DCVG and dig up program (see business case 201), pushing the ILI modifications out in excess of 10 years. It would also mean we would be unable to complete the Elizabeth pipeline modification campaign.

Deferring the Elizabeth campaign would have a short-term impact on the works program, as we would need to complete these remediation works as piecemeal program. A piecemeal approach would be more expensive than delivery the work as part of the overall pipeline modification program. This would also mean remediation works for the 94.4m section of the M55 would need to be undertaken as a separate project under business case SA201.

Moreover, we do not recommend deferring the Elizabeth works beyond the next period because it is a high traffic area located between the Elizabeth train station and bus interchange, and in close proximity to a major shopping centre. If this pipeline was to fail, it would have serious consequences, therefore it is vital we can assess and monitor the condition of this timeline as soon as practicable.

1.5.1 Option 1 – Status quo

Under this option, we would not assess or modify any more of our currently unpiggable TP pipelines. Instead, we would:

- Stop the pipeline design and modification process once we have completed the Sailsbury area campaign
- Not conduct any design works for the Eastern Ring Main campaign
- Continue to conduct ILI on all currently piggable pipelines only
- Continue the DCVG and dig ups program for all other pipelines

All repairs and/or replacement would be conducted reactively as leaks occur or as DCVG and dig ups reveal significant corrosion has occurred, noting the costs associated with remediation are not included in this business case. Should this option be selected, there would need to be a significant uplift in the capex included in business case SA201: Corrosion management on steel pipework. This uplift would provision for more integrity related work to be undertaken, however this would not provide the level of information provided by ILI, which remains the best indicator of condition.

We have identified significant issues related to the installation of non-conductive casings on the M55 TP pipeline at Mountbatten Square in Elizabeth. If we were not to continue with the pipeline modification program, the remediation of the 94.4m section of the M55 would need to be undertaken as a separate project under business case SA201: Corrosion management of steel pipework. This work should not be deferred beyond the next five-year period as it is a high traffic area due to its location between the Elizabeth train station and bus interchange, and proximity to a large shopping centre.

1.5.1.0 Advantages and disadvantages

The advantage associated with this option is that it would result in lower overall capex in the next period. This is because the cost of conducting DCVG is lower than the cost of the design, modification and pigging program over the short term.

However, alternate inspection methods such as DCVG rely on the extrapolation of pipeline sample data as the entire length of the pipeline is not inspected. This results in less effective and efficient dig up, maintenance and repair works over the long term. It should also be highlighted that there are sections of these pipelines, for example in dense metropolitan areas, that simply cannot be excavated meaning the safety and supply risk associated with these pipelines is not diminished substantially below the untreated risk rating even with DCVG and dig ups.

Given the lower effectiveness of alternative inspection methods, it is also likely that we would replace TP pipelines earlier than we would otherwise be able to with information from ILI due to the significant potential risks associated with unidentified corrosion. As the pipelines age and sections of the pipeline remain uninspected, the likelihood that the lives can be safely extended further decreases.

This option is not compliant with accepted industry standard practice as outlined in AS2885.3 and does not reflect a risk reduction of ALARP as is required under our operational risk management framework. It is also not consistent with the NGR as it cannot be considered *such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services*[9].

1.5.1.1 Cost assessment

This option would not result in upfront capex costs associated with this business case. However, should this option be selected, we would expect costs associated with the external assessment of defects (in particular those associated with coatings such as heat shrink sleeves) to be higher over the longer term. This is because, in the absence of the higher quality and more granular information provided by ILI, we are less confident in the location and significance of defects, potentially leading to larger digs, and less well targeted defect assessment and rectification programs.

The costs associated with the additional DCVG and dig ups would also need to be added to the forecasts currently included in the preferred option in business case SA201.

The data limitations associated with alternative inspection methods would also result in us being less confident to extend the lives of these assets as they age significantly beyond the end of their technical design lives, which could result in us replacing our TP pipelines earlier than we perhaps could with the use of information gathered by ILI.

If undertaken as a piecemeal project, we expect the remediation of the Ellizabeth non-conductive pipeline works would be higher than if remediated through the pipeline modification program. We have estimated that we would need to increase the costs included in the business case SA201 by around $1.1 million to ensure these critical works were able to be delivered in the next period.

1.5.1.2 Risk assessment

If this option is selected, we would not reduce the risks associated with undetected corrosion on unpiggable TP pipelines from the status quo. This option is inconsistent with AS2885.3 and is not considered ALARP.

Table 0.7: Risk rating – Option 1

Option 1	**Health & Safety**	**Environ-ment**	**Operations**	**People**	**Compliance**	**Rep & Customer**	**Finance**	**Risk**
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minimal	Major	Minor	Significant	Significant	Catastrophic	
Risk level	High	Negligible	High	Low	Moderate	Moderate	High	

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[9] NGR 79(1)(a)

1.5.1.3 Alignment with vision objectives

Table 0.12 shows how Option 1 aligns with our vision objectives.

Table 0.8: Alignment with vision – Option 1

Vision objective	Alignment
Customer Focussed – Public Safety	N
Customer Focussed – Customer Experience	N
Customer Focussed – Cost Efficient	N
A Leading Employer – Health and Safety	N
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	N
Operational Excellence – Benchmark Performance	N
Operational Excellence – Reliability	N
Sustainable Communities – Enabling Net Zero	-
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	-

Option 1 would not align with our objective of being *Customer Focussed* or *A Leading Employer*, as it would not address the safety and reliability risks associated with undetected corrosion on TP pipelines to ALARP.

Should undetected corrosion cause a significant uncontrolled gas escape, there may also be considerable disruption to more than 10,000 customers should there be an event on our 200 km of unpiggable TP pipeline. This will only increase in likelihood as our pipelines move further beyond the end of their design lives and become more prone to failure. This would not reflect *Operational Excellence*.

Moreover, by not pursuing ILI, we are decreasing the likelihood that we are able to safely extend the life of our pipelines beyond the technical design life of our TP pipelines. If we are unable to demonstrate the integrity of pipelines and develop an economically efficient condition-based replacement program, the pipelines will need to be replaced. This means a significant volume of these high-cost assets will require end of life replacement at around the same time, as most of the pipelines are of a similar age. This will result in significant cost increases and price shock for customers in the future and would not align with our objectives to be *Customer Focussed* and would not achieve *Operational Excellence*.

Not adopting ILI would also not be consistent with accepted industry standard asset management practice as outlines in AS2885.3 and adopted by other network businesses with transmission and TP pipelines.

1.5.2 Option 2 – Design-led

Under this option we would continue to do DCVG and dig ups on our unpiggable pipelines, while we conduct assessments and complete design works for our high and intermediate priority unpiggable pipelines.

This would increase the speed at which we assess our TP pipeline network for piggability and provide a more evidence-based, information-driven planning and prioritisation approach. However, to gain this benefit we would need to wait until all design work on these 10 campaigns was complete before we commenced the modification and pigging works.

Under this option we would be able to commence feature assessment digs and, where considered economically viable to modify the pipeline, complete design works on five of our highest priority pipelines. However, no modification work would be undertaken.

We would instead need to increase the number of DCVG and dig ups (included in business case SA201) as we would not be checking the integrity of these pipelines as part of the initial ILI run.

As identified in Option 1, under this option, we would also need to address the non-conductive casings on the M55 TP pipeline at Mountbatten Square in Elizabeth as a separate project under the business case SA201: Corrosion management of steel pipework. This work should not be deferred beyond the next AA period, as it is a high traffic area due to its location between the Elizabeth train station and bus interchange, and close proximity to a major shopping centre.

1.5.2.0 Advantages and disadvantages

This option is consistent with the need for the assessment of our TP pipelines for piggability under AS2885.3. It would result in an overall program of modification works, that was better scoped at its inception and would ensure that our prioritisation of projects was informed using more granular information on pipeline design and characteristics. This may provide minor additional risk reductions, by bringing forward some higher risk projects should they arise during the assessment stage.

Any benefits associated with the completion of all design works ahead of the delivery of the ILI modification program are expected to be far outweighed by the increased risk associated with the delay in the execution of these projects. Bringing forward the design works for all 10 high and intermediate priority modification projects would limit our ability to deliver the works. At an average design time of 12 months per campaign, this would defer modification and pigging works, and therefore the associated risk reduction for at least another 10 years depending on the engineering design resources available with competing projects.

It is highly plausible that, in the absence of the modification works, within 10 years we may not have enough information to safely extend the lives of one or more of our TP pipelines and need to undertake a significantly more expensive complete pipeline replacement.

1.5.2.1 Assessment

The estimated direct capital cost of this option is $8.4 million as shown in Table 0.9.

Table 0.9: Cost assessment – Option 2, $'000 January 2025

	2026/27	2027/28	2028/29	2029/30	2030/31	Total
Feature assessment digs	1,690	975	1,300	910	260	**5,135**
Design, Engineering and Drafting	660	660	660	660	660	**3,300**
Total	**1,971**	**1,297**	**1,603**	**1,213**	**518**	**8,435**

Costs associated with the additional DCVG and dig ups, and non-conductive casings at Elizabeth would also need to be added to the forecasts currently included in the preferred option in business case SA201.

1.5.2.2 Risk assessment

This option would reduce our compliance risk as it would show that we were working towards assessing our TP pipeline network in accordance with industry standards. However, it would not reduce the risks associated with undetected corrosion on unpiggable TP pipelines significantly enough to change the risk rating from Option 1. It would not result in a risk that could be considered ALARP.

The residual risk outcomes are shown in Table 0.9.

Table 0.10: Risk rating – Option 2

Option 2	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minimal	Major	Minor	Significant	Significant	Catastrophic	
Risk level	High	Negligible	High	Low	Moderate	Moderate	High	

1.5.2.3 Alignment with vision objectives

Table 0.6 shows how Option 2 aligns with our vision objectives.

Table 0.11: Alignment with vision – Option 2

Vision objective	Alignment
Customer Focussed – Public Safety	N
Customer Focussed – Customer Experience	N
Customer Focussed – Cost Efficient	N
A Leading Employer – Health and Safety	N
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	N
Operational Excellence – Benchmark Performance	N
Operational Excellence – Reliability	N
Sustainable Communities – Enabling Net Zero	-
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	-

Although this option allows us to complete some design and assessment works, the risk would not be reduced beyond the untreated risk until we are able to modify and pig those pipelines that are economical to pig. On this basis, this option would not meet our objectives more than Option 1 during the next period.

1.5.3 Option 3 – Rolling deployment

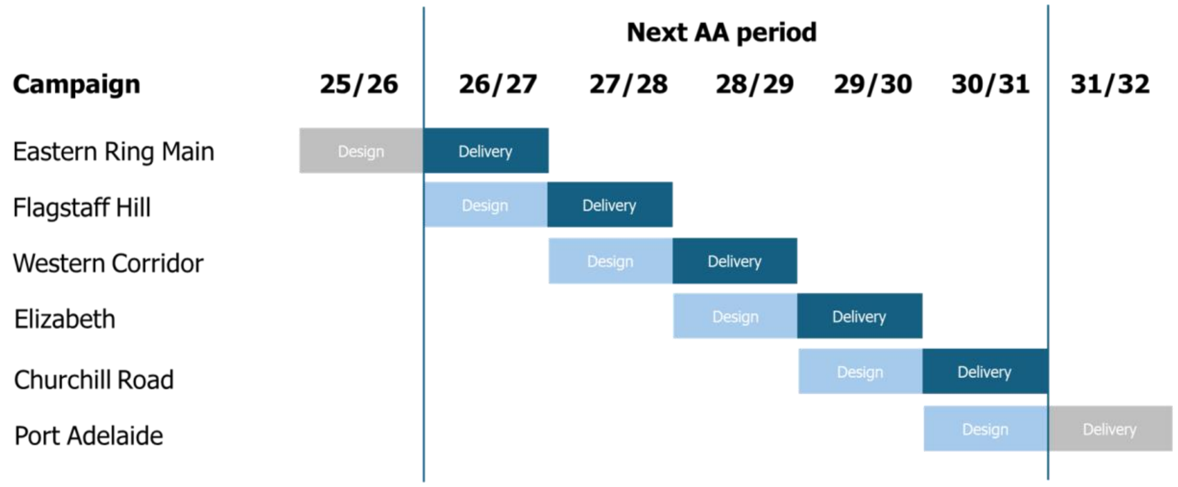
Under this option we would continue the TP pipeline modification program we plan to deliver in the current period. We expect to complete the FEED associated with the Eastern Ring Main campaign in the current period to allow us to deliver the pipeline modification program in the most efficient way possible, and reduce the risks associated with undetected corrosion to ALARP.

As with other options, we anticipate a 12-month FEED period, and 12-month execution period. To optimise the resource base and ensure the most cost effective and flexible portfolio of work we propose a rolling delivery program will allow us to:

- Modify and pig the Eastern Ring Main campaign (M101 and M143) which we are in the process of completing a FEED study for in the current period
- Complete four more ILI campaigns (FEED study, modify and pig) covering the following campaigns:
    - Flagstaff Hill
    - Western Corridor
    - Elizabeth
    - Churchill Road
- Conduct a FEED study for the Port Adelaide campaign ahead of its delivery in the first year of the next period

Figure 0.4 shows the proposed program of work under the rolling delivery approach adopted under this option.

Figure 0.4: Program using rolling delivery method



Note: The design phase for the Eastern Ring Main campaign will be completed in the current AA period despite no allowance being provided by the AER. This reflects our recommended approach for the next period.

1.5.3.0 Advantages and disadvantages

This option is consistent with the need for the assessment of our TP pipelines for piggability under AS2885.3 and standard industry practice of making our TP pipelines piggable and pigging them where economically viable to do so.

This option would allow us to address some of our highest priority pipelines in the next period. This would allow us to gather better information on the integrity of five of our seven highest risk unpiggable pipelines in the next period. Under this approach, we would be able to address our higher and intermediate risk pipelines over the next 10 years, leaving only low risk pipelines unpiggable by 2040.

The risk reduction associated with this option is considered ALARP. However, it comes with an increase in costs in the short term, and requires significant modification works that could be disruptive to customers (supply and works).

It would also require dedicated design and execution teams, increasing our design and capital works delivery teams. This is expected to offset some of the reductions we will see once the mains replacement program is scaled back.

It should also be highlighted that more or better inspections often result in an increase in issues found. The ILI of some of these pipelines may result in an increase in the remediation works, at least in the short term.

1.5.3.1 Cost assessment

The estimated direct capital cost of this option is $34.9 million as shown in Table 0.12.

Table 0.12: Cost assessment – Option 3, $‵000 January 2025

	2026/27	2027/28	2028/29	2029/30	2030/31	Total
Feature assessment digs	1,690	1,300	910	260	975	**5,135**
Design, drafting and engineering	660	660	660	660	660	**3,300**
Execution	4,773	5,526	5,309	6,061	4,773	**26,442**
Total	**7,123**	**7,486**	**6,879**	**6,981**	**6,408**	**34,877**

1.5.3.2 Risk assessment

This option would reduce our risks associated with undetected corrosion on unpiggable pipelines. Specifically, the TP pipeline modification program will reduce the risks associated with health and safety, and operations to moderate as we will have more granular information about the integrity of our TP pipeline network. This will allow us to prioritise our works program to remediate integrity issues based on risk of failure.

It will also reduce our financial risk to low as it will provide sufficient information for us to determine whether we can safely extend the life of our TP pipelines. Without this level of information, we may be unable to demonstrate their integrity, meaning we may end up replacing pipelines before we would otherwise need to. Pipeline replacement is expensive, and the deferral of these significant works is in our interests and the interests of customers where we are confident they are able to be safely deferred.

Conducting the assessments and modification works at a sustainable pace, and over a reasonable timeframe reflects the best balance between risk reduction, delivery capacity and cost for customers. This option is considered ALARP.

The residual risk outcomes associated with this option are shown in Table 0.13.

Table 0.13: Risk rating – Option 3

Option 3	Health & Safety	Environment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Moderate ALARP
Consequence	Major	Minimal	Major	Minor	Significant	Minor	Significant	
Risk Level	Moderate	Negligible	Moderate	Negligible	Low	Negligible	Low	

1.5.3.3 Alignment with vision objectives

Table 0.14 shows how Option 3 aligns with our vision objectives.

Table 0.14: Alignment with vision – Option 3

Vision objective	Alignment
Customer Focussed – Public Safety	Y

Vision objective	Alignment
Customer Focussed – Customer Experience	Y
Customer Focussed – Cost Efficient	Y
A Leading Employer – Health and Safety	Y
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	Y
Operational Excellence – Benchmark Performance	Y
Operational Excellence – Reliability	Y
Sustainable Communities – Enabling Net Zero	-
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	-

This project aligns with the *Customer Focussed* and *Operational Excellence* aspects of our vision.

It delivers for customers by mitigating the safety and supply risks associated with undetected corrosion of our TP pipelines which has the potential to lead to a failure. It will enable us to develop a targeted program to address areas of corrosion, dents and gouges and apply a tailored correction/maintenance program resulting in a more efficient, more proactively managed and safer network.

Enabling ILI will allow us to extend the life of our TP assets beyond the technical design life of 50-80 years thereby avoiding costly investment in the replacement of our TP network. The optimisation of modification campaigns and rolling delivery allows us to complete the program in the most timely and cost efficient manner.

1.6 Summary of options assessment

Table 0.15 presents a summary of how each option compares in terms of the estimated cost, the residual risk rating, and alignment with our objectives.

Table 0.15: Comparison of options

Option	Estimated cost	Treated residual risk rating	Alignment with vision objectives
Option 1: Status quo	No upfront capex, but increase in SA201	High	Does not align with *Customer Focussed* or *Operational Excellence*
Option 2: Design-led	$6.6M and increase in SA201	High	Does not align with *Customer Focussed* or *Operational Excellence*
Option 3: Rolling delivery	$34.9M	Moderate (ALARP)	Aligns with *Customer Focussed* and *Operational Excellence*

1.7 Proposed solution

Option 3 is the proposed solution. It will allow us to:

- Modify and pig the Eastern Ring Main campaign (M101 and M143) which we are in the process of completing a FEED study for in the current period

- Complete four more ILI campaigns (FEED study, modify and pig) covering the Flagstaff Hill, Western Corridor and Elizabeth campaigns and the Churchill Road pipeline
- Conduct a FEED study for the Port Adelaide campaign ahead of its delivery in the first year of the next period

1.7.1 Why is the proposed option prudent?

Option 3 allows us to undertake an assessment of each of our TP pipelines to understand the work required to facilitate ILI as required under AS 2885.3. We have prioritised the program of work in accordance with risk and suitability considerations, and designed our ILI program as a set of campaigns which consider combining modification and pigging scopes to ensure efficient delivery. This option is consistent with standard industry practice.

The delivery of the program of work on a rolling basis is the most efficient option, as it will maintain a relatively smooth pipeline of work for our design and delivery teams. It will also allow us to complete the program of work in a reasonable timeframe, while considering the impact on prices.

Option 1 is non-compliant with standard industry practice and the requirements of AS2885.3 and would result in escalating risks leading us to replace our TP pipelines earlier than we are able to by adopting ILI.

Option 2 would identify the required works to make our TP pipelines piggable, but would not reduce risk during the period, and could result in re-work if the time between the design and execution works were significant.

1.7.2 Estimating the efficient costs

The forecast of the volume of work to be completed over the next AA period is based on the following:

- The volume of pipelines chosen for modification to facilitate ILI is based on current capacity to complete such a volume of work, as well as customer price impact considerations
- A risk based approach has been taken to prioritise TP pipelines with highest risk, including consideration of the pipeline age, coating defects, and the length of pipeline which is situated in high density or sensitive location classes
- The volume of proving investigative excavations, valve replacements, and elbow replacements required are based on a desktop review of the pipeline alignment drawings and our experience in the current period for similar work on M12, M42 and M84

The unit rates used for all projects managed within this program of work include the internal labour, external labour and materials/other costs forecast.

Key assumptions that have been made in the cost estimation for the TP pipeline ILI modification program include:

- The cost estimate is based on costing the activities that comprise the work breakdown structure
- The rates utilised in costing these activities are based on current vendor and contractor rates in 2024 and historical costings
- The scope and work breakdown structure are based on a cost verification

This project will be delivered using a number of external resources. The design, proving excavations, construction, installation and ILI inspection will be completed by contractors with support from internal technicians and engineers. Contractors will be selected through a competitive tender process.

Project delivery practices and controls such as advanced planning and scheduling of work are in place to effectively manage risk in delivery. Proving excavations, construction and installation will be undertaken by multiple crews to ensure critical path activities are not reliant on a single contractor and therefore do not result in project delays.

1.7.3 Consistency with the National Gas Rules

In developing these forecasts, we have had regard to NGR 79 and 74. With regard to all projects, and as a prudent asset manager, we give careful consideration to whether capex is conforming from a number of perspectives before committing to capital investment.

NGR 79(1)

The proposed solution is prudent, efficient, consistent with accepted and good industry practice and will achieve the lowest sustainable cost of delivering pipeline services:

- **Prudent** – The expenditure is necessary in order to ensure that the ongoing integrity of unpiggable TP pipelines is maintained and to reduce the risk of major gas escapes that could impact public safety and reliability of supply, and is of a nature that a prudent service provider would incur. ILI is now standard industry practice, and the rationale for not making a pipeline piggable is required to be documented under AS2885.3.
- **Efficient** – ILI is the most efficient way to gather information on the integrity of our TP pipelines. It provides more granular information on the condition of our assets, and provides better information on which we can rely to determine whether we can safely extend the life of our pipelines. It is the most effective and efficient method of inspecting our TP pipelines. Engineering assessments and design will be carried out by internal staff and field work will be carried out by external contractors based on competitively tendered rates. The approach of conducting FEED studies, with the inclusion of future digs provides us a view of the economic viability of modifying each pipeline, meaning that, should a pipeline be uneconomic (such as the M42) we will not undertake the works. The expenditure is therefore of a nature that a prudent service provider acting efficiently would incur.
- **Consistent with accepted and good industry practice** – The ongoing effective management of the integrity of our TP pipelines is consistent with Australian Standard AS2885.3 Pipelines - Gas and Liquid Petroleum, Part 3: Pipeline Integrity Management. Reducing the risks posed by the corrosion of these assets to as low as reasonably practicable and in a manner that balances costs and risks is also consistent with this standard.
- To **achieve the lowest sustainable cost of delivering pipeline services** – The proposed expenditure will enable us to extend the technical design life of some of its highest cost assets, and manage the future replacement/maintenance schedule more efficiently. Deferring replacement costs and being able to utilise fully-depreciated assets for as long as is safe and practicable will eventuate in the lowest sustainable cost of providing pipeline services.

NGR 79(2)

The proposed capex is justifiable under NGR 79(2)(c)(i) and 79(2)(c)(ii), as it is necessary to maintain the safety and integrity of services.

Corrosion is one of the primary failure modes associated with steel TP pipelines, and any pipeline failure has the potential to interrupt supply to more than 1,000 customers at any one time. Early detection of corrosion is essential to maintain integrity of services, particularly with pipelines that are beyond their design life.

The alternative of relying on DCVG surveys and dig-ups alone is insufficient to manage the integrity risk to an acceptable level, as there are too many sections of the TP pipelines that cannot be dug up or inspected without inserting an inline inspection tool. It is therefore prudent to reconfigure the pipelines to allow pigging and extend the life of the assets, negating the need to incur the high costs of pipeline replacement.

Option 4 achieves the risk reduction required over a reasonable timeframe that is considerate of reducing the risk of cost escalation through resource constraints. We therefore consider Option 4 best meets the requirements of NGR 79(2).

NGR 74

The forecast costs are based on the latest market rate testing and project options consider the asset management requirements as per the Asset Management Strategy. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.

Appendix A Comparison of risk assessments

Treated as SA201	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minimal	Major	Minor	Significant	Significant	Catastrophic	
Risk level	High	Negligible	High	Low	Moderate	Moderate	High	

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minimal	Major	Minor	Significant	Significant	Catastrophic	
Risk level	High	Negligible	High	Low	Moderate	Moderate	High	

Option 2	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minimal	Major	Minor	Significant	Significant	Catastrophic	
Risk level	High	Negligible	High	Low	Moderate	Moderate	High	

Option 3	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Moderate ALARP
Consequence	Major	Minimal	Major	Minor	Significant	Minor	Significant	
Risk Level	Moderate	Negligible	Moderate	Negligible	Low	Negligible	Low	

Appendix B Detailed cost estimate of proposed solution

Labour				
Category	**Description**	**No. items / Metres**	**Unit rate ($/unit)**	**Total cost ($)**
Labour - Contractor	Feature Assessment Digs - Assumes 1 per km	[redacted]	[redacted]	[redacted]
Labour - Contractor	ILI Execution (ILI Contractor, Internal charge back, temp barrels)	[redacted]	[redacted]	[redacted]
Labour - Contractor	Complex - Dual Dia ILI Execution (ILI Contractor, Internal charge back, temp barrels)	[redacted]	[redacted]	[redacted]
Labour - Internal	Design Allowance	[redacted]	[redacted]	[redacted]
Labour - Contractor	Modification / Upgrade	[redacted]	[redacted]	[redacted]
Labour - Internal	Project Management/ Project Engineering	[redacted]	[redacted]	[redacted]
Labour - Internal	Design engineering/Drafting	[redacted]	[redacted]	[redacted]
			[redacted]	[redacted]
Materials				
Category	**Description**	**No. items / Metres**	**Unit rate**	**Total unit cost**
Materials	Launcher and Receiver Sites (Valves, piping, etc..)	[redacted]	[redacted]	[redacted]
Materials - Pipe	ILI Verification Digs	[redacted]	[redacted]	[redacted]
			[redacted]	[redacted]
			[redacted]	[redacted]
Labour - Contractor	Elizabeth Casing - contractor and third party costs	[redacted]	[redacted]	[redacted]
Materials	Elizabeth Casing - pipe, valves, fittings	[redacted]	[redacted]	[redacted]
			[redacted]	[redacted]
Total AA Budget				[redacted]

SA206 – District regulator station overpressure risk reduction

1.1 Project approvals

Table 0.1: Business case SA206 – Project approvals

Prepared by	Muhammad Kashif – Senior Facilities Integrity Engineer
Reviewed by	Alan Creffield – Manager Integrity
Approved by	Michael Iapichello – Head of Engineering and Planning Nick Kafamanis – Head of Capital Delivery Jason Morony – Head of Networks Operations

1.2 Project overview

Table 0.2: Business case SA206 – Project overview

Description of the problem / opportunity	The South Australian (SA) gas distribution network has 90 transmission pressure (TP) and 88 distribution pressure (DP) district regulator stations (DRS). These DRS facilities regulate pressure from a higher-pressure network to a lower pressure network and are critical for maintaining a safe and reliable natural gas supply. Each DRS facility has a service bypass line that should allow us to safely maintain supply to the downstream network while we shut down the DRS and conduct maintenance. This business case seeks to prioritise and remediate those DRSs that are not addressing the risk adequately. Approximately 30 years ago, the standard design for DRS facilities was modified to include a secondary isolation valve on the bypass line to reduce the likelihood of an overpressure event. Subsequent to that, in 1998, the standard was updated to reflect improving industry practice. This meant that a regulator, as opposed to an isolation valve, was standard on DRS bypass lines. In August 2020, the standard design was again updated to the latest industry standard which requires a minimum of two full regulation runs with complaint overpressure protection on each run. Since 2021 all new DRS facilities installed on the network have been designed to the contemporary standard. The latest standard removes the potential for human error to cause overpressurisation of the downstream network and/or customer equipment, but also allow the bypass to be used for an indefinite period of time to allow for delays in maintenance or failure of the primary run. We have been systematically addressing our TP DRSs over the last 10 years. However, we still have 17 TP DRSs without compliant overpressure protection in our network. Recent preliminary studies indicate around half our DP DRSs are currently non-compliant, however, we are using the upcoming period to develop our database such that the following period we can implement a well-informed remediation plan. We have identified and scoped projects for four higher risk DP DRSs that are the primary supplies to the higher density and more sensitive Central Business District (CBD) of Adelaide, and therefore that we also need to address these as a priority, in advance of the DP DRS study. This business case considers the various options for addressing DRS overpressure risks on both TP and CBD DP assets as a cohesive, risk-based prioritised program over the long term.
Untreated risk	As per risk matrix = High
Options considered	• **Option 1** – Replace with industry standard on failure (zero upfront capex)

- **Option 2** – Modify or replace all 17 non-compliant TP DRSs and defer remediation of 4 CBD DRS assets ($16.3 million to $19.5 million)
- **Option 3** – Modify or replace 12 non-compliant TP DRSs and 4 CBD DRS and defer 5 TP DRS assets ($10.9 million)

Proposed solution

The proposed solution is Option 3 as it achieves the required risk reduction associated with overpressurisation at our highest risk DRSs.

The risk-based approach is also considerate of what is deliverable within the next five years. Six of the TP DRS upgrades are full asset replacements due to their supply criticality, which are resource and time intensive, whereas the remaining balance of the DRSs, including the CBD, are augmentations of the existing assets in-situ.

We have optimised the program to achieve them greatest risk reduction possible for the proposed expenditure. The remaining TP DRS projects are proposed to be deferred until the following period.

The proposed solution is in line with current industry good practice and design standards, and consistent with our Asset Management Strategy. It removes the risk of human error contributing to the likelihood of high consequence safety outcomes without interrupting supply.

Estimated cost

The forecast direct cost (excluding overhead) during the next five-year period (July 2026 to June 2031) is $10.9 million.

$'000 Jan 2025	26/27	27/28	28/29	29/30	30/31	Total
TP DRSs	1,570	1,812	2,130	2,038	2,205	**9,755**
CBD DRSs	-	277	277	277	277	**1,110**
Total	**1,570**	**2,089**	**2,407**	**2,315**	**2,482**	**10,866**

Table may not sum due to rounding

Basis of costs

All costs in this business case are expressed in real un-escalated dollars at January 2025 unless otherwise stated.

Treated risk

As per risk matrix = Low

Alignment to our vision

Addressing the risk of overpressure events by installing pressure regulators and secondary isolation valves on the bypass line at TP and CBD DP DRS facilities aligns with our vision in relation to:

- Being *Customer Focussed*, as avoiding overpressurisation events in networks downstream of DRS will help maintain supply and mitigate the risk of asset failure, personnel errors and/or unplanned outages.
- *Operational Excellence*, as proactively augmenting existing assets rather than installing new DRS where possible, using a blend of internal and external resources in a phased project, is the lowest sustainable cost of managing the overpressure risk.

Consistency with the National Gas Rules (NGR)

This project complies with the following National Gas Rules (NGR):

NGR 79(1) – The proposed solution is consistent with good industry practice, several practicable options have been considered, and market rates have been tested to achieve the lowest sustainable cost of providing this service.

NGR 79(2) – The proposed capex is justifiable under NGR 79(2)(c)(i), as it is necessary to maintain the safety of services.

NGR 74 – The forecast costs are based on the latest market rate testing and project options consider the asset management requirements as per the Asset Management Strategy. This business case considers the costs and the benefits of each option. The estimate has been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.

Stakeholder engagement

We are committed to operating our networks in a manner that is consistent with the long-term interests of our customers. To facilitate this, we conduct regular stakeholder engagement to understand and respond to the priorities of our customers and stakeholders. Feedback from stakeholders is built into our asset

	management considerations and is an important input when developing and reviewing our expenditure programs. Our customers have told us their top three priorities are price/affordability, reliability of supply, and maintaining safety. They also told us they expect us to deliver a high level of public safety and are satisfied that this is current practice. The proposed DRS overpressure risk reduction program is designed to ensure the network operates in line with good industry practice, safety standards and compliance requirements, thereby helping maintain a safe and reliable service to customers. These activities are consistent with stakeholder expectations of our network and the level of service our customers value.
Other relevant documents	• Attachment 9.3: Asset Management Plan • Attachment 9.6: Procurement Policy & Procedure • Attachment 9.10: Unit Rates Report • Attachment 9.11: Risk Management Framework • AS/NZS 2885 Australian Standard for Pipelines - Gas & Liquid Petroleum

1.3 Background

DRS facilities are used to supply and regulate pressure from the higher-pressure networks to the lower pressure networks. The AGN SA gas distribution network is supplied by 90 transmission pressure (TP) district regulator stations (DRSs) and 88 distribution pressure (DP) DRSs. TP DRSs typically have an inlet pressure of >1,050Kpa and DP DRSs typically have an inlet pressure of less than 1,050kPa. Of the 88 DP DRSs, 4 of these feed the CBD network and 37 feed the low pressure network that will be upgraded by June 2026 and the regulators removed.

Like all network assets, DRS facilities require periodic maintenance. To allow us to conduct maintenance without disrupting supply, each DRS facility has a service bypass line that allows us to maintain supply to the downstream network while we shut down the DRS to carry out the necessary works.

DRS valves are used to divert flow to the bypass line and bypass isolation valves are manually throttled by a technician to allow continued supply through the bypass line during maintenance activities. If there is no pressure regulator on the bypass line, the throttling is monitored intermittently and the throttling adjusted manually while the technician is working on the DRS facility.

Where a DRS has only one isolation valve and no regulator, there is a higher risk of an overpressure event. Overpressure incidents can have major risk consequences. For example, in 2018 an incident occurred at a regulator station in Boston, USA, which resulted in the overpressurisation of a section of the distribution network. The incident caused a gas escape at numerous domestic meter sets and resulted in significant damage to property, many injuries and a fatality.

While the Boston incident was not directly related to manually throttling isolation valves, it highlighted the serious risk associated with overpressure and led us to review the overpressure risk within the SA network. Our review concluded that the single isolation valve on the bypass line of TP DRSs - which separates two pressure regimes - presents a high risk of overpressurisation.

An overpressure incident also occurred in the Queensland gas distribution network. In June 2024, an isolation valve on a bypass line at a meter set was accidently opened by the technician for an extended period. The customer's installation became overpressurised, damaging the appliance, pressure regulators and other equipment. A review of the Queensland incident showed the issue could easily have resulted in more severe consequences, including a major gas-in-building scenario with potential for ignition. The overpressure incident could have been prevented if there had been a regulator installed on the bypass.

We are therefore continuing to take steps to eliminate the risk of human error when conducting maintenance and thereby mitigate the overpressure risk occurring in the AGN SA network.

1.3.1 Continuous design improvements

The manual throttling method is not good industry practice and approximately 30 years ago the standard design for DRS facilities was modified to include a secondary isolation valve on the bypass line as an initial step to improve safety. This provides a second control and reduces the likelihood of an overpressure event during maintenance.

Using a regulator eliminates the need for manual throttling and monitoring, and therefore removes the risk associated with human error leading to an overpressure event. A secondary isolation valve and a pressure regulating device is the current industry design standard for DRS bypass lines.

In August 2020, the standard design was updated again to the current standard which requires a minimum of two full regulation runs with complaint overpressure protection on each run. This allows for the secondary run to be used for an extended period of time in the advent of an equipment failure or maintenance work that cannot be completed in a single shift.

1.3.2 Overpressure – an ongoing program

We are primarily addressing the TP DRS overpressure work in the upcoming five years, however our records for DP DRSs are not as comprehensive as they are for TP due to the design standards applied at the time of construction. Therefore, before embarking on a broad program for DP DRS modifications we are using the upcoming period to develop a more comprehensive database of information to better plan a program of works for the DP DRS asset class.

Despite this, there are four DP DRSs that are well known and understood, and need to be prioritised as they carry an equivalent level of risk to TP DRSs due to their primary role in supplying a high density and high sensitivity area (the Adelaide CBD).

As part of business case SA106, AGN has successfully implemented overpressure risk reduction work on 18 TP DRSs in the current period. The preferred option in this business case builds on this program, and will see us remove the risks associated with unregulated bypasses on a further 12 TP DRSs and four CBD DRSs over the next period.

Through our experience combined with a review of our network models, we identified six out of the remaining 17 TP sites that are network supply critical. This means these sites cannot be safely taken offline for bypass modification works without causing outages for a large number of customers.

To achieve the modification, a supplementary source of supply must be added before taking the DRS offline. This supplemental source can either be a permanent new DRS in the same general vicinity coupled with decommissioning of the existing DRS or a temporary DRS constructed immediately around the existing DRS, which is in turn modified and then returned to service.

While technically possible to build a temporary DRS, construction of it and modification of the existing DRS has a very similar set of works required to constructing a new DRS. The temporary DRS also comes with complications associated with major modification around existing assets, including:

- These DRSs are generally underground in pits but the temporary DRS will likely need to be above ground, shutting footpaths and/or partial road closures while also exposing the temporary DRS to significant traffic risk
- Modification works to the existing DRS will be slower due to reduced access around the above ground bypass and temporary DRS
- Existing DRS pit space is likely to need to be modified to fit current standard designs, meaning higher unit costs when compared to a new build and may still not be possible to fully comply with current standards

As the installation of a temporary DRS and modification of the existing DRS does not result in a lower cost and comes with additional safety and projects risks it has not been put forward as a discrete option for evaluation in the business case.

Of our 90 TP DRS facilities, we have 17 sites that do not have adequate over pressure protection on their bypass lines, as well as four CBD DRSs that are non-compliant as shown in Table 0.3.

Table 0.3: Summary of DRS non-compliance

TP DRS	**Volume**	**Strategy**
TP DRS that cannot be isolated due to supply criticality	6	Full replacement adjacent
TP DRS that cannot have in-situ bypass modified due to insufficient space	5	Full replacement
TP DRS that can be modified in-situ	6	Modification of bypass line in-situ
TP DRS requiring remediation (a)	**17**	
TP DRS that are compliant to industry standard	73	No action required
Total TP DRS units	**90**	
CBD DP DRS		
CBD DP DRS that can be modified in-situ (b)	**4**	Modification of bypass line in-situ
Total DRS remediation required (a+b)	**25**	

1.4 Risk assessment

Risk management is a constant cycle of identification, analysis, treatment, monitoring, reporting and then back to identification (as illustrated in Figure 0.10). When considering risk and determining the appropriate mitigation activities, we seek to balance the risk outcome with our delivery capabilities and cost implications. Consistent with stakeholder expectations, safety and reliability of supply are our highest priorities.

Our risk assessment approach focuses on understanding the potential severity of failure events associated with each asset and the likelihood that the event will occur. Based on these two key inputs, the risk assessment and derived risk rating

Figure 0.1: Risk management principles

then guides the actions required to reduce or manage the risk to an acceptable level.

Our risk management framework is based on:

- AS/NZS ISO 31000 Risk Management – Principles and Guidelines
- AS 2885 Pipelines-Gas and Liquid Petroleum
- AS/NZS 4645 Gas Distribution Network Management

The *Gas Act 1997* and *Gas Regulations 2012*, through their incorporation of AS/NZS 4645 and the *Work Health and Safety Act 2012*, place a regulatory obligation and requirement on AGN to reduce risks rated high or extreme to low or negligible as soon as possible (immediately if extreme). If it is not possible to reduce the risk to low or negligible, then we must reduce the risk to as low as reasonably practicable (ALARP).

When assessing risk for the purpose of investment decisions, rather than analysing all conceivable risks associated with an asset, we look at a credible, primary risk event to test the level of investment required. Where that credible risk event results in a risk event rated moderate or higher, we will consider investment to reduce the risk.

Seven consequence categories are considered for each type of risk:

1. **Health & safety** – injuries or illness of a temporary or permanent nature, or death, to employees and contractors or members of the public
2. **Environment** (including heritage) – impact on the surroundings in which the asset operates, including natural, built and Aboriginal cultural heritage, soil, water, vegetation, fauna, air and their interrelationships
3. **Operational capability** – disruption in the daily operations and/or the provision of services/supply, impacting customers
4. **People** – impact on engagement, capability or size of our workforce
5. **Compliance** – the impact from non-compliance with operating licences, legal, regulatory, contractual obligations, debt financing covenants or reporting / disclosure requirements
6. **Reputation & customer** – impact on stakeholders' opinion of AGN, including personnel, customers, investors, security holders, regulators and the community
7. **Financial** – financial impact on AGN, measured on a cumulative basis

Our Risk Management Framework, including definitions, is provided in Attachment 9.11.

The primary risk identified for DRS facilities with a single isolation valve and no regulator on the bypass line is the downstream network becoming overpressurised during maintenance of the duty line. The overpressurisation event is the result of failure or malfunction of the bypass valve, or incorrect operation of the valve such as being left open for an extended period. Overpressurisation at the DRS can lead to a major gas escape affecting supply to >10,000 customers or damage to equipment and/or serious harm (fatality).

The untreated risk[10] rating is presented in Table 0.4.

Table 0.4: Risk assessment – Untreated risk

Untreated risk	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minor	Major	Minimal	Significant	Minor	Minor	

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[10] Untreated risk is the risk level assuming there are no risk controls currently in place. Also known as the 'absolute risk'.

Risk Level	High	Low	High	Negligible	Moderate	Low	Low	

The overall untreated risk rating is high, as an overpressure safety or supply incident with major consequences, though unlikely, has the potential to happen in certain circumstances. As shown by the Boston and Queensland incidents, major overpressure risk events have been known to occur elsewhere. Any major overpressure event also has potential to cause compliance, reputational and financial risks due to the harm or supply interruption caused.

1.5 Options considered

Different options have been considered to address the risks associated with the overpressurisation of the downstream network resulting from DRS facilities with a single isolation valve on the bypass. The options are:

- **Option 1** – Continue with current practice of manually throttling supply for all affected TP and CBD DRS facilities during maintenance
- **Option 2** – Modify or replace all 17 non-compliant TP DRSs
- **Option 3** – Modify or replace 12 non-compliant TP DRSs and 4 CBD DRSs

1.5.1 Option 1 – Continue with current practice

Under this option, we would continue the current practice of an operator manually throttling the single isolation valve to allow continued supply through the bypass line during planned and reactive maintenance activities. The manual throttling is then monitored intermittently while the technician is working on the DRS facility.

1.5.1.1 Advantages and disadvantages

The advantage of this option is that it would require no uplift in current expenditure or resourcing. A reactive program costs and risks would be dictated by the rate of failures or safety incidents.

The disadvantages of this option are considerable. In addition to the health and safety risk of the overpressurisation of the network, there is also a significant disadvantage of leaving unsuitable bypass lines on DRSs. The current design with existing controls in place risks asset failure and/or operator error of the manually operated isolation valves. This could result in the overpressurisation of the downstream network and a significant uncontrolled gas escape, damage to the downstream network and subsequent customer outages. Where there is fault on the part of AGN, outages can result in substantial penalties and customer compensation. Outages can also lead to foregone revenue for customers and AGN.

As a prudent asset manager, we consider the risks associated with throttling supply and untreated corrosion is not sustainable.

1.5.1.2 Cost assessment

There are no upfront capital costs associated with this this option. The capital cost of replacing the DRS facilities would only be incurred upon failure, following an overpressure incident, or as part of the future end of life replacement plan and therefore incurred over several regulatory periods.[11]

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[11] These DRS have an estimated remaining life of 20 to 30 years.

In the short term, this would put downward pressure on gas distribution tariffs and allow resources to be deployed elsewhere. However, over the longer term a reactive asset management approach would increase network tariffs and the overall resource requirement.

1.5.1.3 Risk assessment

Option 1 does not address the primary risk associated with DRS overpressure events. The risk is not changed from the untreated risk (see Table 0.5).

Table 0.5: Risk assessment – Option 1

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minor	Major	Minimal	Significant	Minor	Minor	
Risk Level	High	Low	High	Negligible	Moderate	Low	Low	

Though there are a number of current risk controls in place such as procedural controls and telemetered pressure alarms, these controls do not significantly reduce the likelihood of the primary risk event occurring. The current controls also do little to reduce the potential consequence of the risk event. As a result, Option 1 fails to reduce the overall risk rating to low or ALARP as required by our Risk Management Framework.

1.5.1.4 Alignment with vision objectives

Table 0.6 shows how Option 1 aligns with our vision objectives.

Table 0.6: Alignment with vision – Option 1

Vision objective	Alignment
Customer Focussed – Public Safety	N
Customer Focussed – Customer Experience	N
Customer Focussed – Cost Efficient	-
A Leading Employer – Health and Safety	N
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	N
Operational Excellence – Benchmark Performance	-
Operational Excellence – Reliability	N
Sustainable Communities – Enabling Net Zero	-
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	-

Option 1 does not align with our objectives of being *Customer Focussed* or *A Leading Employer*, as it would not address the safety and reliability risks associated with overpressurisation of downstream network assets.

Option 1 also is not *Customer Focussed* and does not reflect *Operational Excellence* as outages for customers are likely to be more prevalent and longer. Moreover, addressing the overpressure events retrospectively is not the most sustainable cost option. Having DRSs with no secondary valve or regulator on the bypass line is also not consistent with current good practice design standards. It is therefore prudent to move to the new standard within a reasonable timeframe rather than maintain the overpressure risk for longer than necessary.

1.5.2 Option 2 – Modify or replace all 17 non-compliant TP DRSs

Under this option we would uplift our investment to remediate non-compliant TP DRS assets at an increased rate compared with the current period. This will allow us to rectify non-compliant assets on all 17 TP DRSs over the next five years. Table 0.7 outlines the full scope of works and the proposed delivery approach.

Table 0.7: DRS upgrade plan – Option 2

DRS type	Units	Strategy	Resource intensity
TP DRS that cannot be isolated due to supply criticality	6	Full replacement adjacent to existing unit	High
TP DRS that cannot have in-situ bypass modified due to insufficient space	5	Full replacement within existing facility	High
TP DRS that can be modified in-situ	6	Modification of bypass line in-situ	Medium
TP DRS requiring modification	**17**	**Complete TP DRSs**	
CBD DRS that can be modified in-situ	4	Defer to next AA period	Medium
CBD DRS requiring modification	**>4**	**Scoping to be completed**	

Under this option, we would fully replace 11 TP DRS facilities, of which six are network supply critical and another five have insufficient space to conduct the necessary works. We would also modify six further TP DRSs in-situ. Modification in-situ replaces the existing bypass line to include a new pipe spool, secondary isolation valve, pressure regulator and pressure monitoring.

The new equipment will be maintained as part of the normal routine preventative maintenance activities on DRS facilities. The additional time required for checking functionality of the new equipment while completing normal scheduled preventative maintenance is not material.

We would not remediate any DP DRSs in the next period but would work to develop a DP program to deliver in future periods.

1.5.2.1 Advantages and disadvantages

The advantages of this option are considerable. This option addresses all our TP assets to prevent the risk of an overpressure event and allow us to conduct routine maintenance in a safe manner. This option will mean:

- The likelihood of an overpressure event becomes remote, as the need for manual intervention is eliminated
- Less gas would be released and fewer customers would be impacted if there is an overpressure event

Option 2 achieves the greatest risk reduction for the portfolio of TP asset. However, the CBD DRSs remain unaddressed, and although these operate at lower pressures, the area risk of overpressure is considered comparable to TP assets given their highly sensitive location in the Adelaide CBD.

The main disadvantage of this option is that the cost is much higher than Option 3. Not only are the costs brought forward, affecting customers' bills over the next five years, but we would also need to engage additional, external resources.

Undertaking the entire replacement program (i.e. 11 full replacements) would require additional external resourcing to deliver the TP workload. Over the next period there is a significant amount of construction work planned for South Australia both within AGN and for other utilities such as SA Water and SA Power Networks. This means we would be competing against multiple other businesses to get contractors. Should we be able to contract sufficient resources to complete the increased work program, it is likely to be prohibitively expensive. We estimate it would cost 20% more to attract additional resourcing to complete the program of work under this option.

1.5.2.2 Cost assessment

The estimated capital cost of this option is between $16.3 million and $19.5 million depending on contractor rates. This estimate is based on current material and labour rates for new installations and assumes the full scope will be delivered over the five-year period as shown in Table 0.8. We have applied a conservative contractor uplift of 20%, but as previously discussed, this could be up to 50% given the tight labour market.

Table 0.8: Cost assessment – Option 2, $'000 January 2025

Option 2	2026/27	2027/28	2028/29	2029/30	2030/31	Total
TP DRS that cannot be isolated due to supply criticality						
Volume	1	1	1	1.5	1.5	**6**
Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TP DRS that cannot have in situ bypass modified due to insufficient space						
Volume	1	1	1	1	1	**5**
Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TP DRS that can be modified in situ						
Volume	1	1.5	1.5	1	1	**6**
Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total cost	**2,869**	**3,112**	**3,430**	**3,337**	**3,504**	**16,252**
Potential contractor uplift	**574**	**622**	**686**	**667**	**700**	**3,250**
Total including uplift	**3,443**	**3,734**	**4,116**	**4,004**	**4,204**	**19,502**

Table may not sum due to rounding

It should be noted that this option is the most expensive option, and also has the highest risk of cost escalation due to the extensive work required when doing a full replacement of a TP DRS. There is a high likelihood that additional external resources would have to be utilised at a significant cost premium.

1.5.2.3 Risk assessment

Option 2 reduces the risk rating associated with overpressurisation to Low. Table 0.9 shows the residual risk associated with the completed 17 DRS facilities if Option 2 is undertaken.

Table 0.9: Risk assessment – Option 2

Option 2	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Rare	Rare	Rare	Rare	Rare	Rare	Rare	Low
Consequence	Major	Minor	Major	Minimal	Significant	Minor	Minor	
Risk Level	Low	Negligible	Low	Negligible	Negligible	Negligible	Negligible	

Having both the second isolation valve and the regulator installed on the bypass line reduces the risk consequences from major to significant, as these controls result in less gas being released and fewer customers being impacted if there is an overpressure event. These two controls combined should also decrease the likelihood of an overpressure event from unlikely to rare, as they eliminate the need for manual intervention.

Option 2 achieves the greatest risk reduction for the portfolio of TP assets (low), however the CBD DRS overpressure risk still remains, and although these operate at lower pressures, the area risk of overpressure is considered comparable to TP assets given its highly sensitive location.

This option is consistent with our Risk Management Framework for the affected assets, and solutions are aligned to current industry practice and design standards.

1.5.2.4 Alignment with vision objectives

Table 0.10 shows how this option aligns with our vision objectives.

Table 0.10: Alignment with vision – Option 2

Vision objective	Alignment
Customer Focussed – Public Safety	Y
Customer Focussed – Customer Experience	Y
Customer Focussed – Cost Efficient	-
A Leading Employer – Health and Safety	Y
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	N
Operational Excellence – Benchmark Performance	Y
Operational Excellence – Reliability	Y
Sustainable Communities – Enabling Net Zero	-
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	-

Option 2 would align with the *Customer Focussed* aspect of our vision, as proactive augmentation of existing facilities will help maintain reliability of supply and mitigate the risk of public safety incidents. Customers (and staff working) in the downstream network will be safe from elevated operating pressures.

Completing works to make our TP DRSs consistent with current design standard means we are operating these critical assets in line with accepted industry practice. We are also deferring the CBD works for a further five years, helping reduce the network tariff impact on customers.

Option 2 may not be considered *Operational Excellence,* as augmenting all the outstanding TP DRS over the next five years at a cost premium would not be considered prudent.

1.5.3 Option 3 – Modify or replace 12 non-compliant TP DRSs and 4 CBD DRS

Under this option, we would fully replace the six network supply critical TP DRS facilities, modify 10 units in situ, which includes the four CBD DRS units. Modification in situ replaces the existing bypass line to include a new pipe spool, secondary isolation valve, pressure regulator and pressure monitoring.

The five TP DRSs that can be replaced in full at the same locations would be deferred until AA7 and added to the DP DRS program that is being developed during the AA6 period.

Table 0.11 outlines the full scope of works and the proposed delivery over the next 10 years.

Table 0.11: DRS upgrade plan for upcoming AA periods – Option 3

DRS type	Units	Strategy	Resource intensity

TP DRS that cannot be isolated due to supply criticality	6	Full replacement adjacent to existing unit	High
TP DRS that cannot have in situ bypass modified due to insufficient space	5	Defer to next AA period	High
TP DRS that can be modified in situ	6	Modification of bypass line in-situ	Medium
TP DRS requiring modification	**17**		
CBD DRSs that can be modified in-situ	4	Modification of bypass line in-situ	Medium
CBD DRSs requiring modification	**>4**	**Scoping to be completed**	

The new equipment will be maintained as part of the normal routine preventative maintenance activities on DRS facilities. The additional time required for checking functionality of the new equipment while completing normal scheduled preventative maintenance is not material.

1.5.3.1 Advantages and disadvantages

The primary advantage of this program of works is that is significantly more balanced and achievable than Option 2, whilst yielding a similar level of risk reduction. The project also addresses the CBD DRS supply points.

Another advantage of this option is that spreading the replacement DRSs over 10 years will ensure we:

- Avoid the costly outsourcing in the tight labour market, thereby reducing the long-term cost impact on customers
- Do not need to interrupt customer supply during heavy supply periods like winter
- Can undertake more work with a balance of replacements and modifications as these are able to be done in parallel

1.5.3.2 Cost assessment

The estimated capital cost of Option 3 is $10.9 million. This estimate is based on current material and labour rates for new installations and assumes the full scope will be delivered over the next five years. The phasing of the expenditure is shown in Table 0.12.

Table 0.12: Cost assessment – Option 3, $'000 January 2025

Option 3	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**Total**
TP DRS that cannot be isolated due to supply criticality						
Volume	1	1	1	1.5	1.5	**6**
Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TP DRS that can be modified in-situ						
Volume	1	1.5	1.5	1	1	**6**
Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CBD DRS that can be modified in-situ						
Volume	-	1	1	1	1	**4**
Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total cost	**1,570**	**2,089**	**2,407**	**2,316**	**2,282**	**10,866**

Table may not sum due to rounding

The risk of cost escalation with Option 3 is significantly lower than Option 2 as it only has six full TP DRS replacements as opposed to 11 in Option 2. This is more achievable from a resourcing perspective, reducing the chances of having to recruit or utilise expensive resources to achieve the full scope of works.

1.5.3.3 Risk assessment

Option 3 reduces the risk rating associated with overpressurisation of the downstream network from high to low. Table 0.13 shows the residual risk associated with the completed 16 DRS facilities if Option 3 is undertaken.

Table 0.13: Risk assessment – Option 3

Option 3	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Rare	Rare	Rare	Rare	Rare	Rare	Rare	Low
Consequence	Major	Minor	Major	Minimal	Significant	Minor	Minor	
Risk Level	Low	Negligible	Low	Negligible	Negligible	Negligible	Negligible	

Having both the second isolation valve and the regulator installed on the bypass line reduces the risk consequences from major to significant, as these controls result in less gas being released and fewer customers being impacted if there is an overpressure event. These two controls combined should also decrease the likelihood of an overpressure event from unlikely to remote, as they eliminate the need for manual intervention.

1.5.3.4 Alignment with vision objectives

Table 0.14 shows how Option 3 aligns with our vision objectives.

Table 0.14: Alignment with vision – Option 3

Vision objective	Alignment
Customer Focussed – Public Safety	Y
Customer Focussed – Customer Experience	Y
Customer Focussed – Cost Efficient	Y
A Leading Employer – Health and Safety	Y
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	Y
Operational Excellence – Benchmark Performance	Y
Operational Excellence – Reliability	Y
Sustainable Communities – Enabling Net Zero	-
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	-

Option 3 would align with the *Customer Focussed* aspect of our vision as proactive augmentation of existing facilities will help maintain reliability of supply and mitigate the risk of public safety incidents. Customers (and staff working) in the downstream network will be safe from elevated operating pressures.

Option 3 reflects *Operational Excellence,* as augmenting the outstanding DP DRS to be consistent with the current design standard means we are operating these critical assets in line with accepted industry practice. We are also undertaking this work over ten years, and the phasing of the project enables us to reduce the most risk in a sustainable program that has the least likelihood of cost escalation, helping reduce the network tariff impact on customers during the next AA period.

1.6 Summary of cost benefit assessment

Table 0.15 presents a summary of how each option compares in terms of the estimated cost, the residual risk rating, and aligning with our objectives.

Table 0.15: Summary of costs and benefits

Option	Estimated cost	Treated residual risk rating	Alignment with vision objectives
Option 1: Status quo	No upfront capex	High	This would fail to achieve safety and reliability objectives or meet current design standards
Option 2: All TP DRSs	$16.3 - $19.5 million	Low	This would align with all relevant vision objectives with the exception that is not the most cost effective solution
Option 3: Balanced program	$10.9 million	Low	This would align with all relevant vision objectives

1.7 Proposed solution

Option 3 is the recommended option as it is the most cost-effective solution to reduce the risk of overpressurisation posed by TP DRS and CBD DP DRS facilities.

1.7.1 Why is the recommended option prudent?

Option 3 reduces the risk of DRS facilities resulting in overpressurisation of the downstream network without compromising supply. Option 1 does not address the risks identified in the Boston and Queensland overpressure events. Option 2 does achieve a significant risk reduction that is comparable to Option 3, but does so at more cost.

Option 3 reduces the risk to ALARP and therefore aligns with our Asset Management Plan and Risk Management Framework. It also aligns with the following vision objectives:

- *Customer Focussed*, as proactive augmentation of existing DRS facilities will help maintain reliability of supply and mitigate the risk of public safety incidents
- *Operational Excellence*, as installing a regulator and secondary valve at DRS facilities is consistent with industry design standards and can be delivered at a cost that is commensurate with the risk reduction

A risk-based approach to deliver this program will be adopted, whereby works will be prioritised on those DRS facilities with highest risk to the network and feeding high consequence areas.

1.7.2 Estimating efficient costs

Key assumptions made in the cost estimation for the DRS overpressure risk reduction project include:

- Work on TP DRS completed during the current period
- TP DRS replacements have been individually costed due to complexity (see Appendix A)

- Costs are based on historical expenditure for modifications noting that these works are not new, with labour rates based on work breakdown structure of activities, and material rates based on historical costs for similar materials

- Estimates derived from contractual rates of vendors to be utilised

- Resource cost based on other similar projects ongoing at present or in previous access arrangement periods

- Original equipment manufacturer contractual rates for spares and labour that are part of our services agreements

1.7.3 Consistency with the National Gas Rules

1.7.3.0.1 NGR 79(1)

The augmentation of TP and CBD DP DRS facilities to install a second isolation valve and pressure regulator on each bypass line is consistent with the requirements of NGR 79(1)(a), Specifically, we consider the capital expenditure is:

- **Prudent** – The expenditure is necessary in order to deliver gas safely and reliably to the downstream network. The proposed risk treatment is consistent with accepted industry practice and current design standards and is proven to address the risk associated with TP and CBD DP DRS facilities. Several practicable options have been considered to address the risk. The proposed expenditure is of a nature that would be incurred by a prudent service provider.

- **Efficient** – The forecast expenditure is based on historical average actuals and tender contract values. The proposed expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur. The project is being delivered at an achievable rate of installation.

- **Consistent with accepted and good industry practice** – The proposed expenditure follows good industry practice by ensuring existing safety risks are addressed to ALARP and in line with current industry practice and design standards. The proposed capital expenditure is therefore such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice.

- To achieve the **lowest sustainable cost of delivering pipeline services** – The sustainable delivery of services includes reducing risks to as low as reasonably practicable while maintaining reliability of supply. The proposed solution allows us to undertake critical maintenance without disrupting customer supply, while at the same time reducing the overpressure risk to ALARP. Further, we have spread the works over a reasonable timeframe that balances risk reduction with network tariff impact.

1.7.3.0.2 NGR 79(2)

The proposed capex is justifiable under NGR 79(2)(c)(i), as it is necessary to maintain the safety of services. Continuing with current practice results in an unacceptable safety risk for customers and our staff, network integrity issues, disruption to customer supply and potential uncontrolled release of gas.

Consistent with the Asset Management Strategy, and as outlined in this business case, current industry practice, to include an additional control and regulator on all TP and DP DRS facility bypass lines will allow us to provide a level of service consistent with industry and design standards, consistent with customer expectations.

1.7.3.0.3 NGR 74

The forecast costs are based on the latest market rate testing and project options consider the asset management requirements as per the Asset Management Strategy. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.

Appendix A [redacted]

SA206 DRS Overpressure Risk Reduction

TP 6 replacements

Labour

Expenditure Year	Category	Description	[redacted]	Unit Rate ($/unit)	Total Unit Cost
	Labour	Construction contractor TP DRS	[redacted]	[redacted]	$2,744,059.55
	Labour	Design TP DRS	[redacted]	[redacted]	$1,282,295.94
	Labour	Commissioning TP DRS	[redacted]	[redacted]	$408,285.30
	Labour	Project Management	[redacted]	[redacted]	$1,000,000.00
	Labour	As building P&ID	[redacted]	[redacted]	$120,000.00

TOTAL LABOUR COST $ $5,554,640.79

Materials

Expenditure Year	Category	Description	No. Items / Metres	Unit Rate	Total Unit Cost
	Material	Fittings	[redacted]	[redacted]	$1,165,319.10
	Material	Regulators	[redacted]	[redacted]	$452,730.00
	Material	Valves	[redacted]	[redacted]	$442,332.00
	Material	Pipe	[redacted]	[redacted]	$247,817.08
	Material	Electrical	[redacted]	[redacted]	$197,421.36

TOTAL MATERIAL COST $ $2,505,619.54

Average unit cost (TP REplacement)	$1,343,376.72
No of sites	6
Total TP replacement	$8,060,260.33

SA206 DRS Overpressure Risk Reduction

TP 6 modifications

Labour

Expenditure Year	Category	Description	Units	Unit Rate ($/unit)	Total Unit Cost
	Labour	Design & Engineering	[redacted]	[redacted]	$14,744.00
	Labour	Fabrication	[redacted]	[redacted]	$6,720.00
	Labour	Contractor site works	[redacted]	[redacted]	$25,000.00
	Labour	Commissioning works	[redacted]	[redacted]	$87,848.00
	Labour	Project Management/Supervision	[redacted]	[redacted]	$14,320.00

TOTAL LABOUR COST $ $148,632.00

Materials

Expenditure Year	Category	Description	No. Items / Metres	Unit Rate	Total Unit Cost
	Material	Fittings	[redacted]	[redacted]	$13,880.00
	Material	Regulators	[redacted]	[redacted]	$18,750.00
	Material	Valves	[redacted]	[redacted]	$37,468.00
	Material	Pipe	[redacted]	[redacted]	$23,450.00
	Material	Electrical	[redacted]	[redacted]	$40,400.00

TOTAL MATERIAL COST $ $133,948.00

Total cost per site (TP modification)	$282,580.00
No of sites	6
Total TP modification	$1,695,480.00

SA206 DRS Overpressure Risk Reduction

CBD DP 4 modifications

Labour

Expenditure Year	Category	Description	Units	Unit Rate ($/unit)	Total Unit Cost
	Labour	Design & Engineering	[redacted]	[redacted]	$12,944.00
	Labour	Fabrication	[redacted]	[redacted]	$6,720.00
	Labour	Contractor site works	[redacted]	[redacted]	$25,000.00
	Labour	Commissioning works	[redacted]	[redacted]	$86,648.00
	Labour	Project Management/Supervision	[redacted]	[redacted]	$12,320.00

TOTAL LABOUR COST $	$143,632.00

Materials

Expenditure Year	Category	Description	No. Items / Metres	Unit Rate	Total Unit Cost
	Material	Fittings	[redacted]	[redacted]	$13,880.00
	Material	Regulators	[redacted]	[redacted]	$18,750.00
	Material	Valves	[redacted]	[redacted]	$37,468.00
	Material	Pipe	[redacted]	[redacted]	$23,450.00
	Material	Electrical	[redacted]	[redacted]	$40,400.00

TOTAL MATERIAL COST $	$133,948.00

Total cost per site (TP modification)	$277,580.00
No of sites	4
Total TP modification	$1,110,320.00

Appendix B Comparison of risk assessments for each option

Untreated risk	Health & Safety	Environment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minor	Major	Minimal	Significant	Minor	Minor	
Risk Level	High	Low	High	Negligible	Moderate	Low	Low	

Option 1	Health & Safety	Environment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minor	Major	Minimal	Significant	Minor	Minor	
Risk Level	High	Low	High	Negligible	Moderate	Low	Low	

Option 2	Health & Safety	Environment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Rare	Rare	Rare	Rare	Rare	Rare	Rare	Low
Consequence	Major	Minor	Major	Minimal	Significant	Minor	Minor	
Risk Level	Low	Negligible	Low	Negligible	Negligible	Negligible	Negligible	

Option 3	Health & Safety	Environment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Rare	Rare	Rare	Rare	Rare	Rare	Rare	Low
Consequence	Major	Minor	Major	Minimal	Significant	Minor	Minor	
Risk Level	Low	Negligible	Low	Negligible	Negligible	Negligible	Negligible	

SA209 – Asset protection

1.1 Project approvals

Table 0.1: Business case SA209 – Project approvals

Prepared by	Matthew Haynes – Access Arrangement Engineer
Reviewed by	Robin Gray – Manager Operations SA
Approved by	Jason Morony – Head of Networks Operations

1.2 Project overview

Table 0.2: Business case SA209 – Project approvals

Description of the problem / opportunity	Some of our below ground gas distribution assets located near roads are vulnerable to strikes from traffic and construction vehicles. We have a number of transmission pressure syphons, valves, and district regulator stations that are not easily visible from above ground and/or have little or no protection barriers to prevent vehicles from hitting or parking on them. The risk associated with these assets was highlighted by an incident on the M6 pipeline on Churchill Rd in May 2024. A third-party road profiler hit the top of a syphon while performing road resurfacing works. The mechanical blind on the syphon, which was sitting just below the asphalt depth, was damaged and a transmission leak occurred. This incident prompted a review of asset protection and accessibility standards across our network, which has identified 23 syphons and 20 buried valves that should be addressed. We therefore propose to excavate, inspect and install syphon chambers on all 43 of these assets and update B4Udig plans with their locations. The installation of syphon/valve chambers will not only ensure these assets are visible and protected; it will also bring them into line with AS 2885.3 – 2018, which requires that buried mechanical fitting should be accessible and subject to periodic inspections. We have also identified 70 Distribution Regulator Sets (DRS) near roads that have insufficient asset protection. DRS are often located on pavements and verges, making them susceptible to being driven over or parked on. Traffic volumes have not only increased near our assets over time, but activities such as lane widening along older main roads, where our DRS assets are typically located, have resulted in closer vehicle proximity at many locations. In order to protect these assets, we propose to install permanent metal bollards around the DRS. Installing asset protection is standard practice for all new DRS. We also conduct ad-hoc reactive installation of bollards at older DRS as threats are identified or as crews become available in the area. Our plan moving forward is to shift to a more proactive and planned program of retrospective bollard installation. We will work through the 70 identified locations, plus any other risky locations we discover, over the next 30-40 years, commencing with 10 locations over the next AA period. These 10 locations will be prioritised by risk. Both the above measures (syphon chambers and bollards at underground DRS) align with industry current practice.
Untreated risk	As per risk matrix = Moderate
Options considered	• **Option 1** – Continue with the current reactive maintenance program, where we repair transmission syphons and offtake valves as they leak or are damaged, and install bollards when we have time and budget or are performing construction/remediation work on the DRS ($zero upfront capital).

- **Option 2** - Install syphon chambers on the 43 identified syphons and buried offtake valves and install bollards on 10 of the highest traffic risk DRS ($1.5 million).
- **Option 3** - Remove all syphons and offtake valves, and install bollards at all 70 DRS sites ($12.4 million).

Proposed solution

Option 2 is the recommended approach. This will significantly reduce the risk of vehicle strikes and represents a deliverable and sustainable program of work.

Option 1 has been dismissed as it will not reduce the risk sufficiently and relies on reactive repairs. Option 3 would essentially eliminate the risk within the next AA period but would come at a significantly higher cost and would push the limits of our delivery capability.

Estimated cost

The forecast direct cost (excluding overhead) during the next five-year period (July 2026 to June 2031) is $1.5 million.

$'000 Jan 2025	26/27	27/28	28/29	29/30	30/31	Total
Asset protection	302	303	303	303	302	1,513

Basis of costs

All costs in this business case are expressed in real unescalated dollars at January 2025 unless otherwise stated.

Alignment to our vision

This project links to the *Customer Focussed* aspect of our vision. It delivers for customers by ensuring acceptable levels of security and reliability of gas supply, as well as improving public safety by reducing the likelihood of asset strikes.

Consistency with the National Gas Rules (NGR)

This project complies with the following National Gas Rules (NGR):

NGR 79(1) – the proposed solution is consistent with good industry practice, several practicable options have been considered, and market rates have been tested to achieve the lowest sustainable cost of providing this service.

NGR 79(2) – proposed capex is justifiable under NGR 79(2)(c)(ii), as it is necessary to maintain the integrity of services.

NGR 74 – the forecast costs are based on the latest market rate testing and project options consider the asset management requirements as per the Asset Management Strategy. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.

Treated risk

As per risk matrix = Low

Stakeholder engagement

Our customers have told us their top three priorities are price/affordability, reliability of supply, and maintaining public safety. They also told us they expect us to deliver a high level of public safety. The proposed installation of additional valves at strategic locations on the transmission pipeline system will help us maintain reliability of supply, while reducing the likelihood of safety issues arising from asset strikes. This asset protection program is therefore consistent with the practices customers have told us they value.

Other relevant documents

- AMS Asset Management Strategy
- AS 2885 Pipelines-Gas and Liquid Petroleum
- AS/NZS 4645 Gas Distribution Network Management

1.3 Background

The gas distribution network spans the breadth of the Adelaide metropolitan area and beyond. This means most of our assets are near roads and heavily trafficked areas. Though most of our gas distribution assets are safely buried underground, some assets are in pavements, road verges and areas where there is potential for them to be struck by vehicles and excavators. Our design standards for *new* assets incorporate protection measures such as protective boxes, high strength traffic bollards, and load-bearing covers. However, the standards at the time of installing some of our older assets did not provide for sufficient protection against traffic and urban sprawl.

Examples of potentially risky assets are transmission pressure syphons and offtake valves that were installed on older mains to allow venting and/or commissioning when the mains were laid. When these mains were installed, protection against traffic may not have been contemplated, as there were no roads or footpaths nearby. As the urban landscape has evolved, the potential for them to come into contact with traffic or excavation has increased.

In some cases, these syphons and valves are located on top of the main and are poorly protected or are under shallow depth of cover. These syphons and valves may also not have been captured in the B4UDig records and can extend up to just under the ground surface above the pipeline. While many of these syphons and valves are not required to operate the network, they are passive assets attached to the network and can result in leaks if they are damaged.

The syphon risk was highlighted by an incident on the M6 pipeline on Churchill Road, in the northern Adelaide metropolitan area during May 2024. A third-party road profiler hit the top of a syphon while performing road resurfacing works. The mechanical blind on the syphon was damaged and a transmission leak occurred, causing major disruption and a public safety hazard.

We have also experienced transmission pressure leaks from buried offtake valves when mechanical fittings have failed due to age. These offtakes are normally old transmission services with an isolation valve buried concurrently to the main.

Historically, we have managed the risk associated with syphons and valves reactively, either removing them after a risk event or when we happen to be working on assets co-located with them. However, the Churchill Road event prompted an assessment of protection levels for all buried syphons and offtakes.

Figure 0.1: Damaged buried syphon

This asset protection review identified 23 syphons and 20 buried valves that are at risk. The review also highlighted a compliance issue with these syphons and valves. These assets have mechanical joints and fittings as well as blinds isolating their outlets. AS2885.3 - 2018 requires mechanical fittings on transmission pressure pipelines to be accessible for inspection so potential leaks and corrosion can be detected easily. These requirements apply to both the syphons and offtake valves.

We therefore propose to excavate, inspect and install syphon chambers on all 43 of these assets and update B4Udig plans with their locations. Installing syphon chambers will make the assets accessible (and so meet compliance requirements), while also offering some protection and greater visibility. This will reduce the likelihood these assets will be struck by traffic or during excavation works.

The asset protection review also considered the risk associated with DRS. Traffic volumes have not only increased near our assets over time, but activities such as lane widening along older main roads, where our DRS assets are typically located, have resulted in closer vehicle proximity at many locations. Eighty-six (86) of our DRS are located below ground level and near to roadways. Sixteen (16) of these have engineered bollards designed to prevent traffic driving over or parking on the DRS lids. The remaining 70 have little or no traffic protection.

Figure 0.2: Example of an older DRS with no bollards and limited asset protection measures

Installing asset protection is standard practice for all new DRS, and we have conducted ad-hoc installation of bollards at older DRS as threats have been identified or where crews have been available in the area. Our plan moving forward is to take proactive approach to installing bollards at existing DRS.

The level of asset protection required depends on the asset type, location, criticality, and frequency of traffic. Figure 0.3 shows a relatively new critical DRS in a highly trafficked area.

Engineered bollards with deep footings were installed when the DRS was constructed, designed to prevent any type of vehicle traffic entering the DRS in an uncontrolled situation (as well as making it highly visible to discourage foot traffic). Figure 0.4 shows an older DRS that has had bollards installed retrospectively to help prevent traffic parking on the DRS lid.

Figure 0.3: New DRS pit with engineered bollards installed during installation

Figure 0.4: Older DRS with bollards installed retrospectively to prevent vehicles parking on the pit lids

Our proposal for the next AA period (2026-31) is to install bollards at 10 DRS sites. This number is based on historical projects and an achievable delivery rate over the period. The 10 sites will be selected based on risk, with delivery coordinated with the ongoing works program for other assets. Bollard installation at underground DRS will be an ongoing project for the life of the network.

The level of asset protection applied at each site will vary on a case-by-case basis and will be determined as we roll through the DRS asset protection project.

1.4 Risk assessment

Risk management is a constant cycle of identification, analysis, treatment, monitoring, reporting and then back to identification. When considering risk and determining the appropriate mitigation activities, we seek to balance the risk outcome with our delivery capabilities and cost implications. Consistent with stakeholder expectations, safety and reliability of supply are our highest priorities.

Our risk assessment approach focuses on understanding the potential severity of failure events associated with each asset and the likelihood that the event will occur. Based on these two key inputs, the risk assessment and derived risk rating then guides the actions required to reduce or manage the risk to an acceptable level.

Figure 0.5: Risk management principles

Our risk management framework is based on:

- AS/NZS ISO 31000 Risk Management – Principles and Guidelines
- AS 2885 Pipelines-Gas and Liquid Petroleum
- AS/NZS 4645 Gas Distribution Network Management

The Gas Act 1997 and Gas Regulations 2012, through their incorporation of AS/NZS 4645 and the Work Health and Safety Act 2012, place a regulatory obligation and requirement on AGN to reduce risks rated high or extreme to low or negligible as soon as possible (immediately if extreme). If it is not possible to reduce the risk to low or negligible, then we must reduce the risk to as low as reasonably practicable (ALARP).

When assessing risk for the purpose of investment decisions, rather than analysing all conceivable risks associated with an asset, we look at a credible, primary risk event to test the level of investment required. Where that credible risk event has an overall risk rating of moderate or higher, we will undertake investment to reduce the risk.

Seven consequence categories are considered for each type of risk:

36. **Health & safety** – injuries or illness of a temporary or permanent nature, or death, to employees and contractors or members of the public
37. **Environment** (including heritage) – impact on the surroundings in which the asset operates, including natural, built and Aboriginal cultural heritage, soil, water, vegetation, fauna, air and their interrelationships
38. **Operational capability** – disruption in the daily operations and/or the provision of services/supply, impacting customers
39. **People** – impact on engagement, capability or size of our workforce

40. **Compliance** – the impact from non-compliance with operating licences, legal, regulatory, contractual obligations, debt financing covenants or reporting / disclosure requirements
41. **Reputation & customer** – impact on stakeholders' opinion of AGN, including personnel, customers, investors, security holders, regulators and the community
42. **Financial** – financial impact on AGN, measured on a cumulative basis

The risk event being assessed is damage to buried and belowground network assets (syphons, buried valves and DRS) due to third party activity, resulting in uncontrolled gas release.

The untreated risk[12] rating is presented in Table 0.3.

Table 0.3: Risk rating – untreated risk

Untreated risk	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Occasional	Occasional	Occasional	Occasional	Occasional	Occasional	Occasional	Moderate
Consequence	Significant	Minimal	Significant	Minor	Significant	Minor	Minor	
Risk Level	Moderate	Low	Moderate	Low	Moderate	Low	Low	

The potential consequences of one of these below ground assets being struck are significant, as shown by the 2024 event on Churchill Road (described above), which affected supply to more than 1,000 customers and caused significant disruption in the area. The proximity of these assets to the general public also gives rise to a significant safety risk in the event they are struck and loss of containment occurs.

The overall untreated risk rating is therefore moderate, which is not ALARP and therefore must be addressed under our risk management framework.

1.5 Options considered

We have identified the following options:

- **Option 1** – Continue with the current reactive maintenance program, where we repair transmission syphons and offtake valves as they leak or are damaged and install bollards when we have time and budget or are performing construction/remediation work on the DRS
- **Option 2** – Install syphon chambers on the 43 identified syphons and buried offtake valves and install bollards on 10 of the highest traffic risk DRS
- **Option 3** – Remove all syphons and offtake valves and install bollards at all 70 DRS sites

1.5.1 Option 1 – Continue current reactive program

Under Option 1 we would continue our current practice of repairing and rectifying buried transmission syphons and valves as they fail or are damaged and install bollards in an ad-hoc manner as other rectification work is completed at the underground DRS.

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[12] Untreated risk is the risk level assuming there are no risk controls currently in place. Also known as the 'absolute risk'.

1.5.1.0 Advantages and disadvantages

The advantage of this option is that it would require no uplift in current expenditure or resourcing. The reactive program would continue as usual, with the costs dictated by the rate of failures or safety incidents.

The disadvantages of this option are considerable. Most significantly, the risk associated with vehicles coming into contact with syphons, valves and DRS will not be diminished, meaning an incident similar to (or worse than) the Churchill Rd event is likely to occur. We would also continue to be non-compliant with Australian Standards for access and inspection of buried syphons and valves.

1.5.1.1 Cost assessment

There would be no additional upfront capital costs with this option. The current number of buried valves and syphons would remain the same.

The costs of addressing asset strikes would be determined by the number of incidents and therefore difficult to forecast with any certainty. The Churchill Rd incident cost approximately $40k to repair, however we were fortunate that the affected syphon had an isolation valve at its base, which is not always the case. If this isolation valve was not installed, or could not be safely accessed, the incident would have cost in excess of $250k due to additional excavating, traffic management, flow stopping and reinstatement requirements.

1.5.1.2 Risk assessment

Option 1 does little to address the risk associated with third party strikes on buried assets, therefore the overall risk rating remains moderate, which is not ALARP. Under our risk management framework, our objective is to reduce any risks rated moderate or higher to low or ALARP.

Table 0.4: Risk rating – Option 1

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Occasional	Occasional	Occasional	Occasional	Occasional	Occasional	Occasional	Moderate
Consequence	Significant	Minimal	Significant	Minor	Significant	Minor	Minor	
Risk Level	Moderate	Low	Moderate	Low	Moderate	Low	Low	

Failing to address a moderate risk rating where there is a practicable treatment available is not consistent with the requirements of our risk management framework and does not reflect the actions of a prudent asset manager.

1.5.1.3 Alignment with vision objectives

Table 0.12 shows how Option 1 aligns with our vision objectives.

Table 0.5: Alignment with vision – Option 1

Vision objective	Alignment
Customer Focussed - Public Safety	N
Customer Focussed – Customer Experience	N
Customer Focussed – Cost Efficient	-
A Leading Employer – Health and Safety	-
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-

Vision objective	Alignment
Operational Excellence – Profitable Growth	-
Operational Excellence – Benchmark Performance	N
Operational Excellence – Reliability	-
Sustainable Communities – Enabling Net Zero	-
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	-

Option 1 would not align with our objective of being *Customer Focussed*, as it would not address the current risk of loss of supply to a significant number of customers in an emergency situation. This option also does not align with our objective of *Operational Excellence*, as prevailing industry standards support mitigation of supply loss risk by installation of valves.

1.5.2 Option 2 – Install syphon chambers on 43 syphons/valves, and install bollards on 10 of the highest traffic risk DRS

Under Option 2 we would excavate, inspect and install syphon chambers on the 43 identified syphons and buried offtake valves, and update B4Udig plans with their locations. We would also install engineered bollards on 10 of the highest traffic risk DRS.

1.5.2.0 Advantage and disadvantages

The main advantage of this option is that it will adequately address the asset risk at an efficient and sustainable rate. The program will address the highest risk DRS first, while significantly reducing the risk of buried valves and syphons being struck. It will also ensure we are compliant with AS 2885.3 – 2018. A further advantage of this option, compared to the other options considered, is that program can be delivered comfortably and is reasonably predictable. This means we can minimise disruption to customers, pedestrians and traffic when conducting the works.

The disadvantage of this option is the cost. Though the overall program expenditure is relatively modest, it does represent an increase in upfront capital costs on asset protection.

1.5.2.1 Cost assessment

The estimated direct capital cost of this option is estimated at $1.5 million. This is based on a materials estimate of ~$15k per site for installing syphon/valve chambers and ~$15k for a typical bollard installation, plus labour costs (see Appendix A).

Table 0.6: Cost estimate – Option 2, $’000 January 2025

Option 2	2026/27	2027/28	2028/29	2029/30	2030/31	Total
Total	302	303	303	303	302	**1,513**

1.5.2.2 Risk assessment

This option reduces the risk from moderate to low. By excavating, inspecting and installing chambers on the 43 identified syphons and offtake valves, the identified compliance risk will be eliminated and the accidental third party damage risk will be mitigated. Updating B4Udig plans with the locations of these valves and syphons will also mitigate the accidental damage risk.

Installing engineered bollards on 10 of the highest traffic risk DRS will help reduce the likelihood of an asset strike to remote and therefore reduce the risk to low.

Table 0.7: Risk rating – Option 2

Option 2	Health & Safety	Environment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Low
Consequence	Significant	Minimal	Significant	Minor	Significant	Minor	Minor	
Risk Level	Low	Negligible	Low	Negligible	Low	Negligible	Negligible	

1.5.2.3 Alignment with vision objectives

Table 0.6 shows how Option 2 aligns with our vision objectives.

Table 0.8: Alignment with vision – Option 2

Vision objective	Alignment
Customer Focussed - Public Safety	Y

Vision objective	Alignment
Customer Focussed – Customer Experience	Y
Customer Focussed – Cost Efficient	-
A Leading Employer – Health and Safety	-
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	-
Operational Excellence – Benchmark Performance	Y
Operational Excellence – Reliability	Y
Sustainable Communities – Enabling Net Zero	-
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	-

Option 2 aligns with our objective of being *Customer Focussed*, as it addresses the supply and health and safety risks. It also does it at a reasonable cost. This option aligns with *Operational Excellence* as it will address the compliance issue and reflects a cost effective solution that is consistent with good industry practice for asset protection.

1.5.3 Option 3 – Remove all syphons and offtake valves and install bollards at all 70 DRS sites

Under Option 3 we would remove all the identified syphons and offtake valves. This would require stoppling and bypasses for all sites. We would also install bollards at all 70 underground DRS sites that are near roads, delivering this as an intensive five-year program.

1.5.3.0 Advantages and disadvantages

The advantage of this option is that it eliminates the risk associated with syphons and buried offtake valves and fully addresses the DRS risk within the period. The buried syphons and offtake valves, while connected to the network, are not essential assets and can be bypassed and removed from the network completely. This would remove them as a hazard completely. Installing bollards at all 70 DRS sites would also mean the risk is eliminated in the shortest time possible, with the potential for securing a more efficient unit (materials) rate if we can deliver it as a short-term targets program.

The disadvantage of this option is the cost. While removing syphons and valves is the best risk treatment, the work is significantly more expensive (~$252k per site). The proposed intensive bollard installation program is deliverable but is at the limits of our delivery capability. While we may be able to secure a lower unit rate for a larger program, we would likely have to redeploy resources from other projects to ensure we can deliver it in full. This limits our flexibility and ability to respond to the ever-changing requirements of our broader capex program. Under this intensive scenario, it would not take much adversity for the DRS program to slip from its schedule.

1.5.3.1 Cost assessment

The estimated direct capital cost of this option is estimated at $12.4 million. This is based on an estimate of ~$252,000k per site for removing syphons /valve chambers and ~$25k for a typical bollard installation.

Table 0.9: Cost estimate – Option 3, $'000 January 2025

Option 3	2026/27	2027/28	2028/29	2029/30	2030/31	Total
Total	2,480	2,480	2,480	2,480	2,480	**12,409**

1.5.3.2 Risk assessment

This option reduces the risk from moderate to negligible. This is because removing the buried syphons and valves completely eliminates the risk of them being struck, while addressing all 70 DRS sites within the AA period substantially reduces the likelihood of them being hit/parked on to rare.

Table 0.10: Risk rating – Option 3

Option 3	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Rare	Rare	Rare	Rare	Rare	Rare	Rare	Negligible
Consequence	Significant	Minimal	Significant	Minor	Significant	Minor	Minor	
Risk Level	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	

While Option 3 provides the greatest risk mitigation, it does so at a substantially higher cost than Option 2. Given the proposed treatment under Option 2 effectively reduces the risk to low, we would have to consider whether reducing the risk to negligible is worth the additional cost.

1.5.3.3 Alignment with vision objectives

Table 0.14 shows how Option 3 aligns with our vision objectives.

Table 0.11: Alignment with vision – Option 3

Vision objective	Alignment
Customer Focussed - Public Safety	Y
Customer Focussed – Customer Experience	Y
Customer Focussed – Cost Efficient	N
A Leading Employer – Health and Safety	-
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	-
Operational Excellence – Benchmark Performance	N
Operational Excellence – Reliability	-
Sustainable Communities – Enabling Net Zero	-
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	-

Option 3 aligns with our *Customer Focussed* strategic pillar, as it addresses the compliance, supply, and health and safety risks. However, Option 3 is not aligned with *Operational Excellence*, as it is a very high cost option that involves an engineering solution that could be argued is more complex and expensive than is absolutely necessary.

1.6 Summary of options assessment

Table 0.12: Comparison of options

Option	**Estimated cost ($ million January 2025)**	**Treated residual risk rating**	**Alignment with vision objectives**
Option 1	Zero upfront capex	Moderate	Does not align with *Customer Focussed* and is not *Operational Excellence*
Option 2	1.513	Low	Aligns with *Customer Focussed* and is *Operational Excellence*
Option 3	12.409	Negligible	Aligns with *Customer Focussed* but is not as *Operational Excellence* as Option 2.

1.7 Recommended option

Option 2 is the proposed solution. This project will be delivered using a combination of internal and external resources. The project will be initiated internally by the asset manager. Design and installation will be completed by contractors. Contractors will be selected through a competitive tender process. Quality assurance and project closure will be handled by internal resources.

1.7.1 Why is the recommended option prudent?

Option 2 is proposed because:

- It supports a consistent approach to supply integrity across the entire network, and reduces the risk consequence from moderate to low at the highest risk locations
- It represents a standard engineering practice, as supported by AS/NZS 4645.1 and AS 2885.1
- It reduces this risk to an acceptable level for a reasonable investment level:
    - Option 1 does not mitigate the identified compliance and health and safety risks so is not considered an appropriate long term outcome
    - While Option 3 may reduce the identified risk further than Option 2 it is at a significantly higher overall cost
- It is consistent with customer and stakeholder requirements and our vision, i.e. Customer Focussed and Operational Excellence
- The delivery of the scope of works is achievable in the time frame envisaged

1.7.2 Estimating efficient costs

The unit rates used for all projects include external and internal planning, labour and materials costs forecast.

Each buried valve and syphon is expected to require excavation, inspection, recoating and syphon chamber installation. The unit rates for these installations is based on historical contractor costs for similar work during the current AA period, this includes rates for external project management and engineering work. As it is proposed that contractor will be utilised for this work this is considered a reasonable basis for the forecast estimate.

With the DRS bollards, we have estimated the costs for a typical installation to be around $30,000 per site. This is based on historical projects and the current market rate for materials. However, the number of bollards and configuration of the asset protection solution will vary by site and will be assessed on a case-by-case basis. However, we submit the $30,000 average estimate is a reasonable assumption of the costs we are likely to incur.

The outcome from using current contractor costs as a basis for the estimate is a forecast capital cost of the rectification works of approximately $1.513 million, as shown in Table 1.14 below.

Table 0.14: Cost estimate – Option 2, $'000 January 2025

	2026/27	2027/28	2028/29	2029/30	2030/31	Total
Labour	145	145	145	145	145	725
Materials	157	158	158	158	157	788
Total	**302**	**303**	**303**	**303**	**302**	**1,513**

This expenditure forecast is also supported by a bottom-up estimate that has generated a similar forecast amount. This is provided in Appendix A.

1.7.3 Consistency with the National Gas Rules

In developing these forecasts, we have had regard to Rule 79 and Rule 74 of the NGR.

NGR 79(1)

The proposed solution is prudent, efficient, consistent with accepted and good industry practice and will achieve the lowest sustainable cost of delivering pipeline services:

- **Prudent** – The expenditure is necessary in order to ensure the risk of third party strikes on buried assets is mitigated. Asset strikes causing disruption to customers and supply have occurred recently. The proposed expenditure is therefore consistent with that which would be incurred by a prudent service provider

- **Efficient** – Installation of syphon/valve chambers is the most practical and cost-effective option. Similarly delivering a sustainable rate of bollard installation will allow us to develop an efficient works program for asset protection. Costs have been based on recent similar valve installation projects. Where contractors are engaged, this will be based on a competitive tender process. The expenditure is therefore consistent with what a prudent service provider acting efficiently would incur

- **Consistent with accepted and good industry practice** – making the buried syphons and offtake valves accessible and capable of being inspected is consistent with the requirements of *AS 2885.3 Pipelines - Gas and Liquid Petroleum, Part 3: Pipeline Integrity Management*. The proposal to install chambers and bollards rather than remove/bypass assets completely is consistent with good practice

- **To achieve the lowest sustainable cost of delivering pipeline services** – We have selected the lowest sustainable cost option, balancing costs against the level of risk reduction that can be achieved. We therefore consider Option 2 represents the lowest sustainable cost of delivering pipeline services

NGR 79(2)

The proposed capex is justifiable under 79(2)(c)(ii), as it is necessary to maintain the integrity of services. The proposed option will allow us to minimise the likelihood of third parties striking or parking on our assets and causing a loss of containment event that can affect supply to thousands of customers.

NGR 74

The forecast costs are based on the latest market rate testing and project options consider asset management requirements as per the Asset Management Strategy. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.

Appendix A – Cost estimate validation (bottom-up)

SA209 Asset Protection

Option 2

Expenditure year	Category	Description	No. items / metres	Unit rate ($/unit)	Total unit cost ($)
	Labour - Contractor	Project Manager - External	[redacted]	[redacted]	[redacted]
	Labour - Consultant	Engineer - External	[redacted]	[redacted]	[redacted]
	Labour - Contractor	Bollard Installation for Transmission DRS	[redacted]	[redacted]	[redacted]
	Labour - Internal	Planned Maintenance	[redacted]	[redacted]	[redacted]
	Labour - Contractor	Traffic Control (2 ppl including ute)	[redacted]	[redacted]	[redacted]
	Labour	Vac Truck	[redacted]	[redacted]	[redacted]
				[redacted]	[redacted]

Expenditure year	Category	Description	No. Items / Metres	Unit rate	Total unit cost
	Materials	Bollards for Transmission DRS	[redacted]	[redacted]	[redacted]
	Materials	Chamber Installation for Transmission Syphon	[redacted]	[redacted]	[redacted]
	Materials	Chamber Installation for Buried Transmission Valve	[redacted]	[redacted]	[redacted]
				[redacted]	[redacted]

Total ($)	1,512,920.00

Appendix B - Comparison of risk assessments

Untreated risk	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Occasional	Occasional	Occasional	Occasional	Occasional	Occasional	Occasional	Moderate
Consequence	Significant	Minimal	Significant	Minor	Significant	Minor	Minor	
Risk Level	Moderate	Low	Moderate	Low	Moderate	Low	Low	

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Occasional	Occasional	Occasional	Occasional	Occasional	Occasional	Occasional	Moderate
Consequence	Significant	Minimal	Significant	Minor	Significant	Minor	Minor	
Risk Level	Moderate	Low	Moderate	Low	Moderate	Low	Low	

Option 2	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Low
Consequence	Significant	Minimal	Significant	Minor	Significant	Minor	Minor	
Risk Level	Low	Negligible	Low	Negligible	Low	Negligible	Negligible	

Option 3	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Rare	Rare	Rare	Rare	Rare	Rare	Rare	Negligible
Consequence	Significant	Minimal	Significant	Minor	Significant	Minor	Minor	
Risk Level	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	

SA210 – RTU replacement

1.1 Project approvals

Table 0.1: Business case SA210 – Project approvals

Prepared by	Tony Giacobbe – Technical Authority, Electrical Instrumentation
Reviewed by	Amir Esmaeili – Manager Technical Authority
Approved by	Michael Iapichello – Head of Engineering and Planning

1.2 Project overview

Table 0.2: Business case SA210 – Project overview

Description of the problem / opportunity	AGN uses a supervisory control and data acquisition (SCADA) system to monitor and report on the flow of gas at critical sites across the network including city gate stations, district regulator stations (DRSs), network fringe points and demand customers. The SCADA system is necessary to ensure we have visibility of how the distribution network is performing. It allows us to manage our assets in a safe and reliable way and address any issues on the network as they arise. The information provided through our SCADA system is also used in planning future investments and mandatory compliance and operational reporting activities. We have a program to proactively replace SCADA equipment when it is technically obsolete (in line with original equipment manufacturer's (OEM) support of the product). In the next five-year period (2026-31) the manufacturer has flagged that certain models of standard remote terminal units (RTUs) will move from the 'limited' to 'retired' product phase. This will mean parts, repairs and security patches will no longer be available. RTUs are used to collect and code data into a format that is transmittable and transmit the data back to the SCADA central station. There are 165 of these soon-to-be-retired RTUs in our network. We plan to replace these RTUs over the next 15 years, commencing with 60 during the next five years. The 60 RTU replacements for the next period will be prioritised by criticality and risk. Delivering the RTU replacements at a rate of ~12 per year is a deliverable and sustainable program, which will allow us to mitigate the risk posed by obsolete RTUs while spreading the cost impact to customers over a longer time period. This business case considers the merits of adopting a faster rate of replacement or moving to reactive replacement only.
Untreated risk	As per risk matrix = High
Options considered	• **Option 1** – Reactively repair and replace RTUs on failure (no upfront capex) • **Option 2** – Commence a proactive program and replace 60 RTUs based on risk ($2.6 million) • **Option 3** – Commence a proactive program and replace all 165 RTUs within the next five years ($7.1 million)
Proposed solution	This business case recommends Option 2. Replacing 60 of the retired RTUs during the period will: • Minimise the risk of the SCADA system failing, leading to a pressure related event, and the associated safety and operational impacts • Enable us to keep on top of the cyclical RTU replacement program, keeping the ongoing number of 'limited' and 'retired' RTUs in our network to a manageable level • Provide visibility of our critical network assets, allowing us to maintain the risk of those assets failing at 'as low as reasonably practicable' (ALARP)

- Maintain compliance with safety and reliability standards (AS 4645, 2885 and 60079), good industry practice, and our Asset Management Strategy

Estimated cost

The forecast direct cost (excluding overhead) during the next five-year period (July 2026 to June 2031) is $2.6 million.

$'000 January 2025	26/27	27/28	28/29	29/32	30/31	Total
RTU replacement	513.4	513.4	513.4	513.4	513.4	**2,566**

Basis of costs

All costs in this business case are expressed in real unescalated dollars at January 2025 unless otherwise stated.

Treated risk

As per risk matrix = Moderate (ALARP)

Alignment to our vision

Replacing retired SCADA equipment proactively in line with the end of its technical design life and reducing the risk of SCADA system failure aligns with the following aspects of our vision:

- *Customer Focussed* as the end-of-life replacement of SCADA equipment across our network will ensure the continued reliability of supply and mitigate the risk of pressure related events, and ensure accurate data is captured and used for customer billing purposes.
- *Operational Excellence* as the cost of replacing assets at the end of their technical design lives as part of a proactive planned program is the lowest sustainable cost of managing the risk of a significant failure of the SCADA system as it is lower cost than a reactive replace on failure program.

Consistency with the National Gas Rules (NGR)

This project complies with the following National Gas Rules (NGR):

NGR 79(1) – The proposed solution is consistent with good industry practice, several practicable options have been considered, and market rates have been tested to achieve the lowest sustainable cost of providing this service.

NGR 79(2) – The proposed capex is justifiable under NGR 79(2)(c)(i), (ii) and (iii), as it is necessary to maintain and improve the safety of services, maintain the integrity of services and comply with regulatory obligations.

NGR 74 – The forecast costs and are based on the latest market rate testing and project options consider the asset management requirements as per the Asset Management Strategy. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.

Stakeholder engagement

Feedback from stakeholders is built into our asset management considerations and is an important input when developing and reviewing our expenditure programs. Our customers have told us their top three priorities are price/affordability, reliability of supply, and maintaining public safety. They also told us they expect us to deliver a high level of public safety and are satisfied that this is current practice.

This proposed SCADA replacement program is designed to ensure the network operates in line with good industry practice, safety standards and compliance requirements, thereby helping maintain a safe and reliable service to our customers. The proposed solution to replace these assets at the end of their technical lives will also help to maintain the reliability of gas supply at the lowest sustainable cost, minimising the impact on customers' gas bills.

Other relevant documents

- Attachment 9.3: Asset Management Plan
- Attachment 9.6: Procurement Policy & Procedure
- Attachment 9.10: Unit Rates Report
- Attachment 9.11: Risk Management Framework
- AS/NZ 4645, 2885 and 60079
- National Gas Market Rules

1.3 Background

The South Australia (SA) natural gas distribution networks deliver gas to over 485,000 customers. We use the SCADA system to monitor and report the gas flow, temperature and pressures at critical sites across the South Australian network in real time.

The effective operation of our SCADA system is required to ensure we have real time visibility of the network, thereby:

- Minimising the risk of the SCADA system failing and leading to a pressure related event, and the associated safety and operational impacts
- Increasing the timeliness of the diagnosis and rectification of a failing or failed critical network assets, thereby minimising the safety and operational impacts
- Allowing us to maintain the risk of those assets failing 'as low as reasonably practicable' (ALARP)
- Allowing us to comply with our reporting obligations
- Improving our ability to comply with safety and reliability standards (AS/NZ 4645, 2885 and 60079, etc)
- Providing critical information about our network assets to allow prudent and efficient investment in our network over the long term
- Helping ensure accurate billing information for our customers
- Assisting in minimising unaccounted for gas (UAFG) losses

We have an ongoing SCADA end of life replacement program, whereby we will typically replace any assets that are at the end of their technical lives and/or are in poor condition. As part of this program, we also address any non-compliance issues where prudent and efficient to do so.

RTUs are an integral component of the SCADA system. They are used to collect and code data into a format that is transmittable and transmit the data back to the central station. Based on the product lifecycle stages advised by [redacted] of our RTUs, we anticipate 165 RTUs across five model families will be moved from 'limited' to 'retired' status in the coming AA period. Limited status means production has ended but the model is still supported for parts / repairs and limited bug fixes. Once the product is transferred to retired status, it is no longer supported by the manufacturer for parts, bug fixes or security patches.

During the next period (2026/27 to 2030/31), we will commence the phased replacement of RTUs that are due to shift from limited to retired status. We have considered various options and volumes of RTU replacement and propose to replace 60 RTUs over the next five years. Our aim is to replace the 165 retired RTUs over the next 10-15 years.

We will prioritise the 60 RTUs for the next AA period by risk, targeting the most critical and poorest condition RTUs first, where practicable. We consider replacing 60 RTUs per five year period is an efficient and sustainable rate of replacement. Though this means there will be a large number of retired RTUs remaining in the network for some time, we believe we can manage this risk through salvaging components from the replaced RTUs, as well as our inventory of spare parts, and using these to maintain the balance of obsolete RTUs until we can replace them.

The RTU replacement program covers several types/brands of RTU (Kingfisher, Point Blue, Site Sentinel) and miscellaneous ancillary telemetry items such as batteries and cable etc.

1.4 Risk assessment

Risk management is a constant cycle of identification, analysis, treatment, monitoring, reporting and then back to identification. When considering risk and determining the appropriate mitigation activities, we seek to balance the risk outcome with our delivery capabilities and cost implications. Consistent with stakeholder expectations, safety and reliability of supply are our highest priorities.

Our risk assessment approach focuses on understanding the potential severity of failure events associated with each asset and the likelihood that the event will occur. Based on these two key inputs, the risk assessment and derived risk rating then guides the actions required to reduce or manage the risk to an acceptable level.

Figure 0.1: Risk management principles

Our risk management framework is based on:

- AS/NZS ISO 31000 Risk Management – Principles and Guidelines
- AS 2885 Pipelines-Gas and Liquid Petroleum
- AS/NZS 4645 Gas Distribution Network Management

The Gas Act 1997 and Gas Regulations 2012, through their incorporation of AS/NZS 4645 and the Work Health and Safety Act 2012, place a regulatory obligation and requirement on us to reduce risks rated high or extreme to low or negligible as soon as possible (immediately if extreme). If it is not possible to reduce the risk to low or negligible, then we must reduce the risk to as low as reasonably practicable (ALARP).

When assessing risk for the purpose of investment decisions, rather than analysing all conceivable risks associated with an asset, we look at a credible, primary risk event to test the level of investment required. Where that credible risk event has an overall risk rating of moderate or higher, we will undertake investment to reduce the risk.

Seven consequence categories are considered for each type of risk:

43. **Health & safety** – Injuries or illness of a temporary or permanent nature, or death, to employees and contractors or members of the public
44. **Environment** (including heritage) – Impact on the surroundings in which the asset operates, including natural, built and Aboriginal cultural heritage, soil, water, vegetation, fauna, air and their interrelationships
45. **Operational capability** – Disruption in the daily operations and/or the provision of services/supply, impacting customers
46. **People** – Impact on engagement, capability or size of our workforce
47. **Compliance** – The impact from non-compliance with operating licences, legal, regulatory, contractual obligations, debt financing covenants or reporting / disclosure requirements
48. **Reputation & customer** – Impact on stakeholders’ opinion of AGN, including personnel, customers, investors, security holders, regulators and the community
49. **Financial** – Financial impact on AGN, measured on a cumulative basis

The primary risk event identified for technically obsolete RTUs is that the RTU malfunctions, leading to undiagnosed failures at the district regulator station (DRS), resulting in the loss of supply, reputational damage and financial penalties.

The untreated risk[13] associated with technically obsolete SCADA equipment is presented in Table 0.3.

Table 0.3: Risk rating – untreated risk

Untreated risk	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Significant	Minor	Major	Minor	Significant	Significant	Minor	
Risk Level	Moderate	Low	High	Low	Moderate	Moderate	Low	

The undiagnosed failure of a DRS or other strategic asset, can lead to interruption of supply to more than 10,000 customers or at least one demand customer consuming >10 TJs per annum. In the absence of a proactive program to replace RTUs, the potential for this event to happen happening is unlikely but possible when certain circumstances prevail and could feasibly be a 1-in-5-year event. This gives rise to a likelihood rating of 'unlikely' in our risk matrix.

However, the potential for >10,000 customers or one demand customer to experience loss of supply is considered a 'major' risk consequence. This results in an overall operational risk rating of high.

RTU failure also poses moderate compliance, reputational and financial risks. This is because SCADA failure can result in incorrect billing information, leading to financial penalties for non-compliance with the National Gas Market Rules. Section 6.3 of AS 4645 requires us to manage and monitor the pressure of the network, which means SCADA failure poses a further compliance risk.

1.5 Options considered

The options considered are:

- **Option 1** – Reactively repair and replace RTUs on failure
- **Option 2** – Commence a proactive program and replace 60 RTUs based on risk
- **Option 3** – Commence a proactive program and replace all 165 RTUs within the next five years

1.5.1 Option 1 – Reactively repair and replace RTUs and associated SCADA equipment on failure

Under this option, we will only replace RTUs and associated components upon failure. We will not proactively replace any of the 165 RTUs that are flagged as falling out of manufacturer support and will rely on our limited current inventory of spare parts to manage the risk.

1.5.1.0 Advantages and disadvantages

An advantage of this option is that it will result in no upfront capex, and may result in lower capex across the period if RTUs do not fail. However, this option has several disadvantages. Primarily, it will do little to address the risk associated with failing RTUs. Spare and salvaged

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[13] Untreated risk is the risk level assuming there are no risk controls currently in place. Also known as the 'absolute risk'.

parts will not be available to maintain the family of 'retired' RTUs, exposing us to significant risk if and when they do fail. The safety and supply implications of a failure are significant, and will likely result in a higher overall cost than proactive replacement.

Waiting for the RTUs to fail before replacing them would not allow us to get head of the ongoing challenge of obsolete SCADA assets. All assets become obsolete eventually, so as a prudent asset manager, our role is to stay ahead of the obsolescence curve where practicable to avoid mass failure, high replacement volumes, and price shock in the future. Replace on failure, while attractive from a short-term cost and deliverability perspective, is not an efficient way to operate a gas distribution network.

1.5.1.1 Cost assessment

Under this option, we will continue to monitor SCADA equipment, including the RTUs, on an annual basis as part of the current preventive maintenance program[14]. However, proactive replacement would not be undertaken. RTUs would only be repaired or replaced when they fail.

With this option, the volume of RTU replacements undertaken in the next five years would be directly driven by the number of breakages/outages experienced on these assets.

While it is not possible to predict with accuracy the number of failures that will occur over the next five years, given many assets have now past their 10-year since end of production point, the likelihood of failure is expected to be higher than during the current access arrangement period. If not treated proactively, it will only increase. Given the higher cost of reactive replacement compared with proactive replacement (potentially two to five times higher per asset depending on asset type and location), the potential cost of works during the next five years is significantly greater than the proposed works program if widespread asset failure arises.

Should asset failure be lower than expected, the overall cost of reactive RTU replacements may be less than forecast. However, the residual risk associated with these assets will not be addressed, as a large number of obsolete assets will remain in the network, with no spare parts available to manage the assets.

These potentially higher costs and unaddressed residual risk are not tolerable for the network or our customers. An entirely reactive replace on failure approach to managing SCADA equipment is not consistent with good asset management practice, and therefore inconsistent with NGR 79(1)(a).

With Option 1, the unit costs incurred would almost certainly be higher. Corrective activities are likely to incur higher costs compared to planned activities due to:

- Additional travel costs (planned activities allow us to share travel costs across different activities at the same location)
- Increased likelihood of overtime and shift penalties (planned activities allow us to optimise staff rostering)
- Additional costs for expediated freight
- Additional costs for removing crews from other planned work to address a corrective maintenance requirement and then remobilising to complete the previous planned work

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[14] The maintenance program includes inspecting, testing, calibrating, cleaning and verifying functionality and calculations for all equipment. Maintenance is not part of this business case. It is part of the operating expenditure forecast.

We may also incur unplanned operating expenditure, as failures could lead to interruption to supply requiring additional customer liaison, and customer relights. Interruption to supply could also costs AGN and its customers in foregone revenues.

It is a generally accepted asset management principle that delivery of proposed works reactively is significantly more expensive than undertaking proactive program of work. In any event, costs associated with a predominantly replace on failure works program would not *be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services*.[15]

1.5.1.2 Risk assessment

Adopting a replacement on failure approach for RTUs will do little to mitigate the risk associated with technically obsolete SCADA equipment. If anything, the risk is likely to increase as the RTUs age and more fall into the retired category. The is inconsistent with our risk management framework, which requires risk to be reduced to low or ALARP.

Table 0.4 shows the residual risk if Option 1 is pursued.

Table 0.4: Risk assessment – Option 1

Option 1	**Health & Safety**	**Environ-ment**	**Operations**	**People**	**Compliance**	**Rep & Customer**	**Finance**	**Risk**
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Significant	Minor	Major	Minor	Significant	Significant	Minor	
Risk Level	Moderate	Low	High	Low	Moderate	Moderate	Low	

1.5.1.3 Alignment with vision objectives

Table 0.5 shows how this option will support the achievement of our vision objectives.

Table 0.5: Alignment with vision objectives – Option 1

Vision objective	**Alignment**
Customer Focussed – Public Safety	N
Customer Focussed – Customer Experience	N
Customer Focussed – Cost Efficient	-
A Leading Employer – Health and Safety	-
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	N
Operational Excellence – Benchmark Performance	-
Operational Excellence – Reliability	-
Sustainable Communities – Enabling Net Zero	-
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	-

Option 1 would not align with our objective of being *Customer Focussed*, as it would not address the risks associated with a significant failure of SCADA assets. Failed or malfunctioning

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[15] NGR 79(1)(a).

RTUs could lead to the undiagnosed failure of a primary supply regulator facility, which has the potential with for network pressure events and loss of supply.

Option 1 would also not align with our objective of *Operational Excellence* as reactive replacement is not and efficient or sustainable method addressing the risks associated with technically obsolete SCADA equipment.

1.5.2 Option 2 – Commence the proactive program and replace 60 RTUs based on risk

Under this option, we would commence the proactive replacement of the RTUs that have been identified by the manufacturer as moving to 'retired' status. Option 2 proposes a program of work spread over a 10 to 15-year period, meaning we will replace approximately 60 RTUs during the next five-year period.[16]

Other SCADA equipment would be maintained[17] on a three-monthly basis for equipment at DRSs and gate stations, or otherwise annually. Equipment would then be reactively repaired or replaced when it fails.

1.5.2.0 Advantages and disadvantages

The main advantage of this approach is that it will enable us to manage the risk associated with obsolete RTUs in an efficient manner. By proactively replacing 60 RTUs per AA period, we will be able to address the highest risk RTUs, while salvaging sufficient spare parts to be able to manage the balance of retiring RTUs and keep the risk to ALARP. Sixty RTUs over five years is a sustainable and deliverable rate of replacement and achieves a good balance between risk mitigation and cost impact.

A disadvantage of this approach is that a significant volume of obsolete RTUs will remain in the network for up to 15 years. While we can mitigate this risk to some extent by salvaging spares to maintain the RTU fleet, it means the older RTUs may be more susceptible to failure and cybersecurity issues than the newer RTUs as contemporary software patches will not be available.

1.5.2.1 Cost assessment

The estimated capital cost of proactively replacing all SCADA equipment that has reached the end of its technical design life over the next five years is $2.6 million. This estimate is based on current material and labour rates for new installations (see Table 0.6).

Table 0.6: Cost estimate – Option 2, $'000 January 2025

	2026/27	2027/28	2028/29	2029/30	2030/31	Total
Labour	354.8	354.8	354.8	354.8	354.8	**1,773.8**
Materials	158.6	158.6	158.6	158.6	158.6	**793**
Total	**513.4**	**513.4**	**513.4**	**513.4**	**513.4**	**2,566.8**

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[16] RTUs may be replaced reactively on a breakdown basis, separate from these planned RTU replacements. The project will consider this and to help ensure a reactive solution is ready to go.

[17] The maintenance program includes inspecting, testing, calibrating, cleaning and verifying functionality and calculations for all equipment. Maintenance is not part of this business case. It is part of the operating expenditure forecast.

1.5.2.2 Risk assessment

Option 2 reduces the risk associated with obsolete RTU equipment from high to moderate. While the risk will not be fully mitigated, due to the high number of obsolete RTUs remaining in the network, the oldest and highest risk RTUs will be targeted first, which we consider will reduce the likelihood of the primary risk event occurring from 'unlikely ' to 'remote'. It should be noted that by the end of the 10 to 15-year RTU replacement program, we expect the likelihood to decrease further to 'rare'.

Table 0.7: Risk assessment – Option 2

Option 2	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Moderate (ALARP)
Consequence	Significant	Minor	Major	Minor	Significant	Significant	Minor	
Risk Level	Low	Negligible	Moderate	Negligible	Low	Low	Negligible	

Proactively replacing technically obsolete RTUs reduces the likelihood that a network failure will go undetected and helps mitigate the potential for significant supply or safety risk events.

Of the options considered, Option 2 is guided by the OEM's recommendations, achieves an acceptable risk reduction, reducing the risk to low, and is therefore consistent with our risk management framework, as well as current industry practice and design standards.

1.5.2.3 Alignment with vision objectives

Table 0.8 shows how this option will support the achievement of our vision objectives.

Table 0.8: Alignment with vision objectives – Option 2

Vision objective	Alignment
Customer Focussed – Public Safety	Y
Customer Focussed – Customer Experience	Y
Customer Focussed – Cost Efficient	-
A Leading Employer – Health and Safety	-
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	Y
Operational Excellence – Benchmark Performance	Y
Operational Excellence – Reliability	-
Sustainable Communities – Enabling Net Zero	-
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	-

Option 2 would align with our objective of being *Customer Focussed*, as it would address the public safety or reliability risks associated with a significant failure of the SCADA system. It will reduce the risk of failure of RTUs leading to an undiagnosed failure of a primary supply regulator facility with potential for network pressure event.

Option 2 would also align with our objective of *Operational Excellence* as it is the lowest sustainable cost option of addressing the risks associated with technically obsolete SCADA equipment. It is also consistent with industry standards and manufacturer recommendations for this type of equipment.

1.5.3 Option 3 – Commence the proactive program and replace all 165 RTUs within the next five years

Under this option, a strategy will be implemented to systematically replace the RTU equipment in a retired or end of life status. The approach is similar to Option 2, however we would aim to replace all 165 retired RTUs within the next AA period.

Other SCADA equipment would be maintained on a three-monthly basis for equipment at district regulator sites and gate stations, or otherwise annually. Equipment would then be reactively repaired or replaced when it fails.

1.5.3.0 Advantages and disadvantages

The main advantage of Option 3 is that it will mitigate the risk fully within the shortest time possible. It will also set important precedents for proactive SCADA management and ramping up of resources quickly, from which we can learn and apply to future asset management programs.

The disadvantages of Option 3 are cost and deliverability. While it is feasible to replace all 165 retired RTUs within five years, this would be the limit of our delivery capabilities and is dependent on our ability to source additional materials and resources. Focusing resources on the RTU replacement program may also impact our ability to deliver other work programs or respond quickly to new risks during the period. Replacing all obsolete RTUs within one AA period would cost around three times as much as Option 2 over the next five years.

1.5.3.1 Cost assessment

The estimated capital cost of proactively replacing all SCADA equipment that has reached the end of its technical design life over the next five years is $7.1 million. This estimate is based on current material and labour rates for new installations (see Table 0.9).

Table 0.9: Cost estimate – Option 3, $’000 January 2025

	2026/27	2027/28	2028/29	2029/30	2030/31	Total
Labour	975.6	975.6	975.6	975.6	975.6	**4,878**
Materials	436.2	436.2	436.2	436.2	436.2	**2,180.8**
Total	**1,411.7**	**1,411.7**	**1,411.7**	**1,411.7**	**1,411.7**	**7,058.7**

1.5.3.2 Risk assessment

Option 3 reduces the risk associated with obsolete RTUs from high to low by the end of the AA period. Replacing all 165 retired RTUs reduces the likelihood of the primary risk event occurring to ‘rare’.

Table 0.10: Risk assessment – Option 3

Option 3	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Rare	Rare	Rare	Rare	Rare	Rare	Rare	Low
Consequence	Significant	Minor	Major	Minor	Significant	Significant	Minor	
Risk Level	Negligible	Negligible	Low	Negligible	Negligible	Negligible	Negligible	

Of the options considered, Option 3 is consistent with OEM recommendations, achieves the greatest risk reduction, reducing the risk to negligible, and is therefore consistent with our risk management framework.

Option 3 however, is the highest cost option with and will require significant outsourcing technical and project management labour to complete such a large program, which may result in significant unit cost increases above the predicted rates given the very tight market for E&I resources with the energy transition. AGN does not believe the additional short term cost to customers is warranted against the additional risk reduction received over Option 2.

1.5.3.3 Alignment with vision objectives

Table 0.11 shows how this option will support achievement of our vision objectives.

Table 0.11: Alignment with vision objectives – Option 3

Vision objective	Alignment
Customer Focussed – Public Safety	Y
Customer Focussed – Customer Experience	Y
Customer Focussed – Cost Efficient	-
A Leading Employer – Health and Safety	-
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	N
Operational Excellence – Benchmark Performance	N
Operational Excellence – Reliability	-
Sustainable Communities – Enabling Net Zero	-
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	-

Option 3 would align with our objective of being *Customer Focussed*, as it would address the public safety or reliability risks associated with a significant failure of the SCADA system. It will reduce the risk of failure of RTUs leading to an undiagnosed failure of a primary supply regulator facility with potential for network pressure event.

Option 3 would not align with our objective of *Operational Excellence* as it is a higher cost option of addressing the risks associated with technically obsolete SCADA equipment.

1.6 Summary of options assessment

Table 0.12 presents a summary of how each option compares in terms of the estimated cost, the residual risk rating, and aligning with our vision objectives.

Table 0.12: Comparison of options

Option	Estimated cost	Treated residual risk rating	Alignment with vision objectives
Option 1: Replace on failure	No upfront capex	High	This would fail to achieve safety and reliability objectives or meet industry standards
Option 2: Replace 60 proactively	$2.6 million	Moderate (ALARP)	This would align with all relevant vision objectives
Option 3: Replace 165 proactively	$7.1 million	Low	This would fail to meet our *Operational Excellence* objectives

1.7 Proposed solution

Option 2 is the proposed solution to reduce the risk posed by technically obsolete SCADA equipment. The option delivers the optimal result with given resources.

1.7.1 Why is the recommended option prudent?

Option 2 delivers a solution that reduces the risk associated with RTUs identified as technically obsolete is reduced from moderate to low at the lowest cost. It is therefore consistent with good industry practice, our Asset Management Strategy and the risk management framework.

It supports the vision and values in relation to:

- Being *Customer Focussed*, as it would address the public safety or reliability risks associated with a significant failure of the SCADA system. It will reduce the risk of failure of the SCADA system leading to an undiagnosed failure of a primary supply regulator facility with potential for network pressure event or the extended response to containment of emergency situations.
- *Operational Excellence*, as it is the least cost option of addressing the risks associated with technically obsolete SCADA equipment. It is also consistent with industry standards and conforms to the requirements of the National Gas Market Code, and the Gas Distribution Code and is therefore consistent with our objective of working within industry benchmarks.

A risk-based approach to deliver this program will be adopted, whereby works will be prioritised for SCADA equipment with highest risk to the network.

1.7.2 Estimating efficient costs

Key assumptions made in the cost estimation for the RTU replacement program include:

- Costs based on historical expenditure noting that these works are standard practice
- Estimates derived from contractual rates of vendors to be utilised
- Resource cost based on other similar projects ongoing at present or in previous AA periods
- OEM contractual rates for spares and labour that are part of our services agreements

Table 0.13 presents a breakdown of the SCADA equipment replacement program by cost category.

Table 0.13: Project cost estimate, by cost category, $'000, January 2025

	2026/27	2027/28	2028/29	2029/30	2030/31	Total
Labour	354.8	354.8	354.8	354.8	354.8	**1,773.8**
Materials	158.6	158.6	158.6	158.6	158.6	**793**
Total	**513.4**	**513.4**	**513.4**	**513.4**	**513.4**	**2,566.8**

Table may not sum due to rounding

1.7.3 Consistency with the National Gas Rules

NGR 79(2)

The proposed capex is justifiable under NGR 79(2)(c)(i) as it is necessary to maintain the safety of services. Not addressing the risk of obsolete RTUs results in an unacceptable safety risk for customers and our staff, network integrity issues, disruption to customer supply and potential uncontrolled release of gas.

The continued proactive replacement of our SCADA equipment has proven to reduce the risk of a significant SCADA system failure and will allow us to maintain a level of service consistent with customer expectations. Moreover, this is the most cost-efficient solution to reduce the identified risk and is therefore consistent with good industry practice.

NGR 79(1)

The continued proactive replacement of our retired RTUs is consistent with the requirements of NGR 79(1)(a). Specifically, we consider that the capital expenditure is:

- **Prudent** – The expenditure is necessary in order to deliver gas safely and reliably to the downstream network and ensure accurate billing information for our customers. Proactive replacement of technically obsolete SCADA equipment is therefore prudent and necessary to continue to supply services. The proposed risk treatment is consistent with accepted industry practice and current design standards and is proven to address the risk of a significant failure of our SCADA system. Several practicable options have been considered to address the risk. The proposed expenditure is therefore consistent with that which would be incurred by a prudent service provider.
- **Efficient** – Historical average actuals and tender contract values have been used to inform cost estimates. The proposed expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.
- **Consistent with accepted and good industry practice** – The proposed expenditure follows good industry practice by ensuring that existing safety risks are addressed to low or ALARP and in line with current industry practice and design standards. The proposed capex is therefore such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice.
- To achieve the **lowest sustainable cost of delivering pipeline services** – The sustainable delivery of services includes reducing risks to as low as reasonably practicable and maintaining reliability of supply, whilst achieving the lowest sustainable costs by undertaking the works in line with the relevant useful life and adopting proven new and emerging technologies and techniques that reduce long-term costs.

NGR 74

The forecast costs are based on the latest market rate testing and project options consider the asset management requirements as per the Asset Management Strategy. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.

Appendix A Comparison of risk assessments

Untreated risk	**Health & Safety**	**Environ-ment**	**Operations**	**People**	**Compliance**	**Rep & Customer**	**Finance**	**Risk**
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Significant	Minor	Major	Minor	Significant	Significant	Minor	
Risk Level	Moderate	Low	High	Low	Moderate	Moderate	Low	

Option 1	**Health & Safety**	**Environ-ment**	**Operations**	**People**	**Compliance**	**Rep & Customer**	**Finance**	**Risk**
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Significant	Minor	Major	Minor	Significant	Significant	Minor	
Risk Level	Moderate	Low	High	Low	Moderate	Moderate	Low	

Option 2	**Health & Safety**	**Environ-ment**	**Operations**	**People**	**Compliance**	**Rep & Customer**	**Finance**	**Risk**
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Moderate (ALARP)
Consequence	Significant	Minor	Major	Minor	Significant	Significant	Minor	
Risk Level	Low	Negligible	Moderate	Negligible	Low	Low	Negligible	

Option 3	**Health & Safety**	**Environ-ment**	**Operations**	**People**	**Compliance**	**Rep & Customer**	**Finance**	**Risk**
Likelihood	Rare	Rare	Rare	Rare	Rare	Rare	Rare	Low
Consequence	Significant	Minor	Major	Minor	Significant	Significant	Minor	
Risk Level	Negligible	Negligible	Low	Negligible	Negligible	Negligible	Negligible	

Appendix B Cost breakdown of options

Option 2 equipment breakdown costs

Labour				
Category	**Description**	**No. items / metres**	**Unit rate ($/unit)**	**Total unit cost ($)**
Labour - Contractor	Project Manager - External	[redacted]	[redacted]	[redacted]
Labour - Consultant	Engineer - External	[redacted]	[redacted]	[redacted]
Labour	Commissioning	[redacted]	[redacted]	[redacted]
Labour	Installation - telemetry items (RTU)	[redacted]	[redacted]	[redacted]
Labour	Configuration/SCADA	[redacted]	[redacted]	[redacted]
Labour	Drawings/Doc	[redacted]	[redacted]	[redacted]
Labour	Installation - miscellaneous telemetry items			[redacted]
			[redacted]	[redacted]

Materials				
Category	**Description**	**No. items / metres**	**Unit rate ($)**	**Total unit cost ($)**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
			[redacted]	[redacted]

Option 3 equipment breakdown costs

Labour

Category	Description	No. items / metres	Unit rate ($/unit)	Total unit cost ($)
Labour - Contractor	Project Manager - External	[redacted]	[redacted]	[redacted]
Labour - Consultant	Engineer - External	[redacted]	[redacted]	[redacted]
Labour	Commissioning	[redacted]	[redacted]	[redacted]
Labour	Installation - telemetry items (RTU)	[redacted]	[redacted]	[redacted]
Labour	Configuration/SCADA	[redacted]	[redacted]	[redacted]
Labour	Drawings/Doc	[redacted]	[redacted]	[redacted]
Labour	Installation - miscellaneous telemetry items			[redacted]
			[redacted]	[redacted]

Materials

Category	Description	No. items / metres	Unit rate ($)	Total unit cost ($)
Materials - Electrical	RTU units - Kingfisher / Point Blue / Site Sentinel	[redacted]	[redacted]	[redacted]
Materials - Electrical	RTU Spares	[redacted]	[redacted]	[redacted]
Materials - Electrical	Miscellaneous telemetry items	[redacted]	[redacted]	[redacted]
			[redacted]	[redacted]

SA211 – Network monitoring

1.1 Project approvals

Table 0.1: Business case SA211 – Project approvals

Prepared by	Hsuan Chen – Graduate Engineer
Technical SME	Kirsty Boucher – Asset Planning Analyst / Umair Ali – Senior Process Engineer
Reviewed by	Martijn Vlugt – Manager Asset Planning
Approved by	Michael Iapichello – Head of Engineering and Planning 30/05/2025 Jason Morony – Head of Networks Operations 30/5/25

1.2 Project overview

Table 0.2: Business case SA211 Project overview

Description of the problem / opportunity	The South Australia (SA) natural gas distribution networks includes more than 8,700 km of pipelines, which deliver gas to over 485,000 customers in metropolitan and regional SA. We use supervisory control and data acquisition (SCADA) pressure monitoring equipment across our networks to:
	• Detect network issues such as over/under pressurisation
	• Allow the effective and efficient response to asset failures and emergency events
	• Maintain compliance with Australian Standard 4645
	• Provide a view of network performance during high and peak demand conditions
	• Facilitate efficient and prudent network modelling that:
	  • Helps us operate the network safely and reliably in real time
	  • Informs investment decisions, in particular, in relation to network expansion and augmentation
	Our SCADA capabilities are relatively immature when compared to other energy networks and are limited to remote monitoring rather than remote control. Having sufficient monitoring points and visibility is therefore essential to our ability to operate the network efficiently and safely.
	As the networks grow or customer usage patterns change, the flow dynamics and pressures within the distribution system also change. This drives the need for additional pressure monitoring equipment, typically at the fringe of the network or at district regulating stations (DRS), so we can see and manage any changes in network performance. Installing pressure monitoring is an ongoing program of work, whereby we periodically review network pressures and visibility to identify where monitoring is required. We have identified that over the next five years, additional monitoring is required at:
	• 11 fringe points; and
	• 2 DRS facilities.
	In addition to installing these additional monitoring points, we are also looking at improving our 24/7 monitoring capabilities. Currently, the AGN SA networks are not monitored by a dedicated operator/technician around the clock. While networks are monitored during business hours, outside of business hours we rely on an on-call rotation using text messaging and responding only to critical SCADA alarms.
	This business case considers the merits of installing the additional network fringe monitoring and establishing a suitable 24/7 monitoring facility and round-the-clock supervision.

Untreated risk	• As per risk matrix = Moderate

Options considered

- **Option 1** – Discontinue the network pressure monitoring program and monitor pressure at the fringes of our networks using temporary solutions (no additional upfront capex)
- **Option 2 –** Install new pressure monitoring points at the identified fringe and DRS sites ($0.5 million capex)
- **Option 3** – Install new pressure monitoring points at the identified fringe and DRS sites, and establish a 24/7 monitoring room (~$1.0 million capex + $1 million opex)

Proposed solution

Option 3 is the proposed solution because:

- Installation of permanent network monitoring is a proven solution to mitigate the risk of supply/safety issues, and is a relatively low cost investment
- We have experience installing this equipment, the volumes deliverable, and it makes sense to continue the program
- The solution aligns with AS 4645 and good industry practice

Estimated cost

The forecast capital cost is $986,000, with a recurrent opex uplift of $200,000 per year for the additional labour resource.

Capex $'000 Jan 2025	26/27	27/28	28/29	29/30	30/31	Total
Additional pressure monitoring	137	137	92	60	60	486
24/7 monitoring capability (room set up and equipment)	500	-	-	-	-	500
Total	**637**	**137**	**92**	**60**	**60**	**986**

Opex $'000 Jan 2025	26/27	27/28	28/29	29/30	30/31	Total
24/7 monitoring capability (labour resource)	200	200	200	200	200	1,000

Basis of costs

All costs in this business case are expressed in real unescalated dollars at January 2025 unless otherwise stated.

Treated risk

As per risk matrix = Low

Alignment to our vision

This project aligns with to the *Customer Focussed* aspect of our vision. It delivers for customers by mitigating the risk to public health and safety, as well as promoting security and reliability of gas supply.

It also links to the *Operational Excellence* aspect of our vision. Installing pressure monitoring telemetry equipment is consistent with good industry practice and is the most cost-effective solution to address the safety and supply risks that result from having insufficient real time information about the operation and performance of our network assets.

Consistency with the National Gas Rules (NGR)

NGR 79(1) – the proposed solution is consistent with good industry practice, several practicable options have been considered, and market rates have been tested to achieve the lowest sustainable cost of providing this service.

NGR 79(2) – proposed capex is justifiable under NGR 79(2)(c)(i) and(ii), as it is necessary to maintain the safety and integrity of network services.

	NGR 74 – the forecast costs are based on the latest market rate testing and project options consider the asset management requirements as per the Asset Management Strategy. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.
Stakeholder engagement	Our customers have told us their top three priorities are price/affordability, reliability of supply, and maintaining public safety. They also told us they expect us to deliver a high level of public safety and are satisfied that this is current practice. Installation of pressure monitoring on DRSs and fringe points in high demand areas at the fringes of our networks will ensure we can monitor pressure on those assets in real time. Having a 24/7 monitoring capability will also allow us to respond quickly to all critical and warning SCADA alarms, and prevent issues before they become major problems. This will allow us to maintain reliability of supply at the lowest sustainable cost, minimising the impact on customers' gas bills.
Other relevant documents	• Asset Management Strategy – AGN South Australia Networks – 420-PL-AM-0010

1.3 Background

The SA gas distribution networks includes more than 8,700 km of pipelines covering Adelaide and its surrounding areas, as well as regional centres like Mount Gambier, Whyalla, Port Pirie Barossa Valley, Murray Bridge and Berri. The networks deliver gas to over 485,000 customers.

The breadth of our South Australian networks means we rely on SCADA equipment to monitor how the network is performing and identify risk and operational issues. We use SCADA pressure monitoring equipment to:

- Detect network issues such as over/under pressurisation
- Allow the effective and efficient response to asset failures and emergency events
- Maintain compliance with Australian Standard 4645
- Provide a view of network performance during high and peak demand conditions
- Facilitate efficient and prudent network modelling that:
  - Helps us operate the network safely and reliably in real time
  - Informs investment decisions, in particular, in relation to network expansion and augmentation

Our gas networks are continually changing. As new customers connect or established customers disconnect, gas flow and pressures can change significantly, particularly if a new demand customer (consumption >10 TJ per year) shifts its operations. Similarly, as our network expands further into new greenfield sites, the extremities of our distribution system physically change. To keep up with these changes and to ensure we can operate the networks effectively, it is essential our SCADA equipment is operational, is being monitored, and that monitoring points are in the right locations. We therefore have an ongoing pressure monitoring program whereby we assess our monitoring capabilities and coverage.

Our program for the next AA period has two components:

1. Installation of additional monitoring points
2. Establish 24/7 monitoring capability

These are discussed in the following sections.

1.3.1 Additional monitoring points

We regularly review the effectiveness of our pressure monitoring equipment and identify any areas where additional monitoring may be required. This is an ongoing program of work. Based on our historical SCADA program, we add 10-20 new monitoring points over a five year period.

We generally install additional monitoring at points at:

- Established areas of the network that are experiencing organic growth
- Areas that have experienced poor pressure supply or modelling shows they are approaching minimum pressures
- New fringe points (extremities) where the network has been expanded, or programs such as mains replacement or regulator removals/replacements have shifted fringe points
- Regional network city gates
- Locations for hydrogen blended gas model validation

Additional monitoring is typically installed at district regulator stations (DRS) or at the fringe of the network. For the next AA period (FY27 to FY31), we have identified that new pressure monitoring equipment is required at 11 fringe points and 2 DRS locations. These are summarised in the following table.

Table 0.3: List of sites identified for new monitoring equipment

	Site type	Location	Reason	Pressure regime	Suburb	Comments	Network
1	Fringe	Tallarook Road	Extremity	HP	Hawthorndene	Network extremity southeast of the HP	HP302 Central
2	Fringe	Luis Drive	High Growth	HP	Angle Vale	Network extremity central east of the HP	HP300 Central North
3	Fringe	Wigley Drive	Extremity	HP	McLaren Vale	Network extremity southeast of the HP (250 kPa)	HP301 Central South
4	Fringe	William Avenue	Extremity	MP	Henley Beach South	Network extremity west of the MP (90 kPa)	MP202 Metro Central
5	Fringe	Horwood Avenue	Extremity	MP	Rostrevor	Network extremity north of the MP (90 kPa)	MP202 Metro Central
6	Fringe	Esquire Circuit	Extremity / High Growth	HP	Roseworthy	Network extremity north of the HP (350 kPa)	HP300 Central North
7	Fringe	Corymbia Avenue / Grevillea Parade	High Growth	HP	Buckland Park	Network extremity central east of the HP (350 kPa)	HP325 Virginia
8	Fringe	Tozer Road	Extremity	HP	Waterloo Corner	Network extremity north of the HP (350 kPa)	HP335 Waterloo Corner
9	Fringe	York Road	Extremity	MP	Port Pirie West	Network extremity north east of the MP (90 kPa)	MP309 Port Pirie
10	Fringe	Bridges Street	Extremity	HP	Peterborough	Network extremity west of the HP (350 kPa)	HP308 Peterborough
11	Fringe	Daws Road	Extremity	HP	EDWARDSTOWN	Blended network	Blended network

	Site type	Location	Reason	Pressure regime	Suburb	Comments	Network	
12	R1744	FROST ROAD	DRS	H1/M2	SALISBURY	Key DRS for network	MP203 North	Metro
13	R1739	FROST ROAD	DRS	H1/M2	SALISBURY	Key DRS for network	MP203 North	Metro

1.3.2 24/7 monitoring capability

The AGN South Australian network is not monitored by a dedicated operator around the clock. Currently, a single technician in Adelaide monitors the SA networks during business hours only. Outside of business hours, we rely on an on-call rota whereby supervisors use mobile phone text messaging to receive alarms and then use their laptop to log in to the SCADA system and assess the issue and whether to escalate. In the event of an emergency, the on-call supervisor would contact on-call operations staff for a field response.

Under these arrangements, only critical SCADA alarms are responded to outside of business hours. Other warning alarms and measures (e.g. pressure spikes) are not proactively monitored. This means warning alarms that occur outside of business hours are not responded to until they become critical alarms, by which time there is a risk the issue may have escalated into a serious problem.

Not having a 24/7 monitoring capability means there is a significant risk SCADA alarms can be missed[18] and our emergency response significantly delayed. Moreover, our reliance on remote log in and text messaging means we are dependent on mobile communication coverage as well as the availability of the supervisory staff.

Further, the monitoring environment for our SCADA technicians is suboptimal. The person monitoring the network during business hours does not have a dedicated or secure workspace. They sit an open plan office environment, subject to high levels of foot traffic and potential distractions. Put simply, our monitoring capability lags significantly behind our peers, is not consistent with industry good practice, and places our business and our customers at unnecessary and avoidable risk.

To improve our monitoring capabilities and minimise the risk of network alarms being missed (or slow response times), we propose to establish a dedicated monitoring room with modern and fit-for-purpose equipment in a secure and distraction-free environment. We will also increase our SCADA resourcing so that the monitoring room can be manned around the clock, meaning we will have true 24/7 monitoring rather than a minimal on-call crew outside of business hours.

Our plan is to establish the room at one of our existing office/depot locations. The room will be used to monitor the AGN SA network, as well as our Victorian and Queensland networks, which also lack of 24/7 monitoring. Costs will be shared between the three network businesses, with expenditure allocated to each entity via a one-third split.

It is important to highlight that our immediate focus is on remote monitoring rather than remote control. The extent to which we currently use our SCADA system to *control* the gas distribution networks is limited. Our capabilities are confined to monitoring, recording and direct control (i.e. sending field technicians to site). As such, the proposed new facility will be

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[18] A critical SCADA alarm was recently missed in the Packenham networks. Thankfully the alarm did not relate to a serious incident, however, it highlights the potential for critical or overpressure events to be overlooked.

a monitoring room rather than a traditional control room contemplated by ISO 11064 (Design of Control Centre).

We therefore envisage the monitoring room facility to contain the following equipment:

- SCADA systems
- Data servers and storage
- User interface and control panels
- Communication systems
- Alarm systems
- Ergonomic work station, desks and chairs
- Security access / lockable doors

In addition to the physical equipment, we will require additional resources to man the monitoring room. The 24-hour nature of the role means we would need six full time equivalent (FTE) resources working 8-hour shifts to monitor the room, ensuring we have at least two individuals (one technical and one SCADA technician) available at all times.

We currently have 3 FTE covering daytime and on-call monitoring. Costs for the proposed uplift of 3 FTEs, would be allocated across the three AGN network businesses.

1.4 Risk assessment

Risk management is a constant cycle of identification, analysis, treatment, monitoring, reporting and then back to identification. When considering risk and determining the appropriate mitigation activities, we seek to balance the risk outcome with our delivery capabilities and cost implications. Consistent with stakeholder expectations, safety and reliability of supply are our highest priorities.

Our risk assessment approach focuses on understanding the potential severity of failure events associated with each asset and the likelihood that the event will occur. Based on these two key inputs, the risk assessment and derived risk rating then guides the actions required to reduce or manage the risk to an acceptable level.

Figure 0.1: Risk management principles

Our risk management framework is based on:

- AS/NZS ISO 31000 Risk Management – Principles and Guidelines
- AS 2885 Pipelines-Gas and Liquid Petroleum
- AS/NZS 4645 Gas Distribution Network Management

The Gas Act 1997 and Gas Regulations 2012, through their incorporation of AS/NZS 4645 and the Work Health and Safety Act 2012, place a regulatory obligation and requirement on us to reduce risks rated high or extreme to low or negligible as soon as possible (immediately if extreme). If it is not possible to reduce the risk to low or negligible, then we must reduce the risk to as low as reasonably practicable (ALARP).

When assessing risk for the purpose of investment decisions, rather than analysing all conceivable risks associated with an asset, we look at a credible, primary risk event to test the level of investment required. Where that credible risk event has an overall risk rating of moderate or higher, we will undertake investment to reduce the risk.

Seven consequence categories are considered for each type of risk:

- **Health & safety** – injuries or illness of a temporary or permanent nature, or death, to employees and contractors or members of the public
- **Environment** (including heritage) – impact on the surroundings in which the asset operates, including natural, built and Aboriginal cultural heritage, soil, water, vegetation, fauna, air and their interrelationships
- **Operational capability** – disruption in the daily operations and/or the provision of services/supply, impacting customers
- **People** – impact on engagement, capability or size of our workforce
- **Compliance** – the impact from non-compliance with operating licences, legal, regulatory, contractual obligations, debt financing covenants or reporting / disclosure requirements
- **Reputation & customer** – impact on stakeholders' opinion of AGN, including personnel, customers, investors, security holders, regulators and the community
- **Financial** – financial impact on AGN, measured on a cumulative basis

A summary of our risk management framework, including definitions, is provided in Attachment 9.11.

The primary risk associated with insufficient pressure monitoring on our network is the extended response times in emergencies, and deferral of necessary augmentation work resulting in an overpressure event that leads to loss of supply or a safety event.

The untreated risk[19] rating is presented in Table 0.4.

Table 0.4: Risk assessment – untreated risk

Untreated	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Moderate (not ALARP)
Consequence	Significant	Minimal	Significant	Minor	Minor	Minor	Minor	
Risk Level	Moderate	Negligible	Moderate	Low	Low	Low	Low	

The risk of having insufficient monitoring capability is rate as moderate. This is because a loss of supply event for the DRSs has the potential to affect more than 1,000, but less than 10,000 residential customers.

1.5 Options considered

We have identified the following options:

- **Option 1** – Discontinue the network pressure monitoring program and monitor pressure at the fringes of our networks using temporary solutions
- **Option 2** – Install new pressure monitoring points at the identified fringe and DRS sites
- **Option 3** – Install new pressure monitoring points at the identified fringe and DRS sites, and establish a 24/7 monitoring room

These options are discussed in the following sections.

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[19] Untreated risk is the risk level assuming there are no risk controls currently in place. Also known as the 'absolute risk'.

1.5.1 Option 1 – Discontinue the network pressure monitoring program and monitor pressure at the fringes of our networks using temporary solutions

Under Option 1, we would discontinue the current DRS telemetering program. We would install temporary data loggers at network fringe points when a poor pressure problem is identified. This approach is a reactive program that does not provide real time notification of when pressures fall below minimum levels.

1.5.1.0 Advantages and disadvantages

An advantage of this option is the potential for lower costs. If network pressures do not fall and we do not encounter issues, then we would avoid the need to install permanent pressure monitoring.

The disadvantages of this reactive approach are the continued risk exposure and the lack of control/visibility. Gas consumption patterns change over time, particularly as new customers connect (or disconnect) from the distribution network. These changes affect network pressures. It is vital we have visibility of how the network is performing at any one time so we can manage the risk. Relying on our limited fleet of temporary data loggers to monitor poorly performing parts of the network reactively, exposes us and our customers to risk of loss of supply and under pressure safety incidents, as we would not be able to monitor all potential problem areas all of the time.

If under or overpressure risk events occur, it would ultimately drive higher overall costs to respond to emergencies and repair any damage/failed assets.

1.5.1.1 Cost assessment

There is no upfront capital expenditure related to pressure monitoring of the identified strategic, fringe of network sites included in this business case. However, we would continue to incur the following costs:

- Ongoing operational costs by means of a reactive program of installing temporary data loggers at network fringe points when customer complaints are received or to investigate network performance during peak times
- Processing data logger data into electronic systems, and reactive augmentation planning to provide quick-fix solutions
- Supply outages or restrictions to groups of consumers resulting from unidentified areas where pressures are below the minimum
- Operational costs associated with less efficiently planning and completing augmentation projects

This option is inconsistent with our risk management framework and our vision objectives.

1.5.1.2 Risk assessment

Option 1 mains the risk at moderate, which is not as low as reasonably practicable (ALARP). This option does not mitigate the consequences of supply risk events due to the lack of visibility on the DRSs. Moreover, the likelihood of pressure events downstream of the DRS in fringe of network areas. It is therefore not consistent with our Asset Management Strategy or Risk Management Framework which requires risk to be reduced to low or ALARP.

The risk assessment is shown in Table 0.5.

Table 0.5: Risk rating – Option 1

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Moderate (Not ALARP)
Consequence	Significant	Minimal	Significant	Minor	Minor	Minor	Minor	
Risk Level	Moderate	Negligible	Moderate	Low	Low	Low	Low	

1.5.1.3 Alignment with vision objectives

Table 0.12 shows how Option 1 aligns with our vision objectives.

Table 0.6: Alignment with vision objectives – Option 1

Vision objective	Alignment
Customer Focussed - Public Safety	-
Customer Focussed – Customer Experience	N
Customer Focussed – Cost Efficient	-
A Leading Employer – Health and Safety	-
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	-
Operational Excellence – Benchmark Performance	-
Operational Excellence – Reliability	N
Sustainable Communities – Enabling Net Zero	-
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	-

Option 1 would not align with our objective of being *Customer Focussed or Operational Excellence*, as it would not address the risks of extended response times due to the lack of remote telemetry. Undetected asset failure can lead to a significant uncontrolled gas escape, resulting in loss of supply and ongoing reliability issues.

1.5.2 Option 2 – Install new pressure monitoring points at the identified fringe and DRS sites

Under Option 2, we would install new pressure monitoring points at strategic sites in our networks. This will involve installing pressure monitoring on two high-pressure to medium-pressure DRS: R1744 and R1739. We will also install new monitoring equipment on assets at the fringe of our network in 11 strategic sites. Of these, 8 are on the high-pressure network, and the other 3 are medium pressure.

1.5.2.0 Advantages and disadvantages

The major advantage of this option is that it will enable us to monitor pressures in parts of the network that are currently unmonitored and/or likely to experience changes in pressure over time. It also avoids the need for costly deployment and redeployment of temporary data loggers on a reactive basis. Permanent pressure monitoring points also help in emergencies and for leak response situations when a section of the network has to be isolated to repair a main. The impact of isolating low pressure areas can be monitored in real time, minimising risk of losing supply.

The disadvantage of this option is the upfront capital cost. A further disadvantage of this option is that it includes no provision for uplifting our 24/7 monitoring capability, which means we will continue to rely on minimal monitoring capability outside of business hours.

1.5.2.1 Cost assessment

The estimated capital cost of this option is $0.5 million. This estimate is based on current material and labour rates. Table 0.8 provides a breakdown of costs.

Table 0.7: Cost estimate – Option 2 $’000 Jan 2025

Option 2	2026/27	2027/28	2028/29	2029/30	2030/31	Total
DP DRS	77	77	-	-	-	154
Fringe points	60	60	92	60	60	332
Total capex	**137**	**137**	**92**	**60**	**60**	**486**

Further information on the cost estimate is provided at Appendix A.

1.5.2.2 Risk assessment

Option 2 reduces the risk from moderate to low. This is because having remote SCADA pressure monitoring equipment at the identified sites reduces the likelihood that pressure events or emerging pressure issues will go undetected, and therefore reduces the likelihood of loss of supply to customers. The additional remote monitoring equipment will provide adequate pressure monitoring across the network, helping us plan and schedule augmentation/maintenance works as required and before minor pressure issues become major problems.

Table 0.8: Risk rating – Option 2

Option 2	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Low
Consequence	Minor	Minimal	Significant	Minor	Minor	Minor	Minor	
Risk Level	Negligible	Negligible	Low	Negligible	Negligible	Negligible	Negligible	

This option is consistent with our Asset Management Strategy and Risk Management Framework.

1.5.2.3 Alignment with vision objectives

Table 0.6 shows how Option 2 aligns with our vision objectives.

Table 0.9: Alignment with vision objectives – Option 2

Vision objective	Alignment
Customer Focussed - Public Safety	-
Customer Focussed – Customer Experience	Y
Customer Focussed – Cost Efficient	Y
A Leading Employer – Health and Safety	-
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	-
Operational Excellence – Benchmark Performance	-

Vision objective	Alignment
Operational Excellence – Reliability	Y
Sustainable Communities – Enabling Net Zero	-
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	-

Option 2 would align with the *Customer Focussed* aspect of our vision, as installing additional pressure monitoring equipment helps prevent, identify and address network issues that may result in a loss of containment or loss of customer supply.

The proposed solution is also reflective of *Operational Excellence,* as the benefits for long term asset management and the avoidance of short term reactive work significantly outweigh the investment.

1.5.3 Option 3 – Install new pressure monitoring points at the identified fringe and DRS sites, and establish a 24/7 monitoring room

Under Option 3, we would continue the current program and install new pressure monitoring points at strategic sites in our networks. This will involve installing pressure monitoring on 2 DRS: R1744 and R1739. We will also install new monitoring equipment on assets at the fringe of our network in 11 strategic sites. Of these, 8 are on the high-pressure network, and the other 3 are medium pressure.

Under Option 3 we would also set up and resource a 24/7 monitoring room at one of our existing depot/office locations and increase our resourcing to cover 24/7 shift patterns and leave.

1.5.3.0 Advantages and disadvantages

The advantage of this options is that it will enable us to continuously monitor pressures in parts of the network that are currently unmonitored and/or likely to experience changes in pressure over time. It also avoids the need to costly deployment and redeployment of temporary data loggers on a reactive basis. Permanent pressure monitoring points along with continuous monitoring also helps significantly in emergencies and for leak response situations when a section of the network has to be isolated to repair a main. The impact of the isolation to low pressure areas can be monitored in real time, minimising risk of losing supply.

The 24/7 monitoring capability would ensure emergencies are responded to quickly and that critical and important alarms are not missed. Setting up a dedicated monitoring room would also improve the quality of our monitoring capability during business hours, as the operator would be working in a fit-for-purpose environment, with fewer distractions.

The disadvantage of this option is the upfront capital cost and additional opex requirement. However, the proposed investment is relatively small and will be shared equally across AGN's three network businesses, meaning the cost impact on AGN SA customers will be minimal.

1.5.3.1 Cost assessment

The estimated capital cost of this option is $1.0 million. This estimate is based on current material and labour rates. Table 0.10Table 0.8 provides a breakdown of costs.

Table 0.10: Cost estimate – Option 3 $'000 Jan 2025

Option 3	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**Total**
DP DRS	77	77	-	-	-	154
Fringe points	60	60	92	60	60	332
Monitoring room equipment and fit out (1/3 allocation to AGN SA)	500	-	-	-	-	500
Total capex	**637**	**137**	**92**	**60**	**60**	**986**
24/7 SCADA resource (1/3 allocation to AGN SA).	200	200	200	200	200	1,000
Total opex	**200**	**200**	**200**	**200**	**200**	**1,000**

The monitoring room costs will be shared equally across the AGN SA, Victoria and Queensland network businesses. Capital costs to establish the monitoring room include design, project management, equipment and fit out. We do not intend on acquiring or renting a new facility for the monitoring room, we will use a property already owned by the business. This will allow us to keep costs to a minimum.

A detailed specification of equipment and requirements for the monitoring room has not yet been developed, and will be established in early 2026 as this project progresses. The current estimate is based on desktop research and experience of similar projects, as well as initial conversations with potential vendors.

The opex component is for three additional FTE, the costs for one of which will be charged to AGN SA. The current estimate of ~$200,000 per year for a SCADA technician is based on assessment of market rates and current remuneration of comparable employees. Again, these labour costs will be subject to refinement as the project progresses and subject to market testing.

Further information on the cost estimate is provided at Appendix B.

1.5.3.2 Risk assessment

Option 3 reduces the risk from moderate to low. As per Option 2, having remote SCADA pressure monitoring equipment at the identified sites reduces the likelihood that pressure events or emerging pressure issues will go undetected, and therefore reduces the likelihood of loss of supply to customers. The additional remote monitoring equipment will help us plan and schedule augmentation/maintenance works as required and before minor pressure issues become major problems.

Having the 24/7 monitoring capability reduces the likelihood that pressure events will go undetected and will improve our emergency response times. Therefore, in practice, Option 3 offers a greater risk reduction than Option 2. However, the risk matrix has insufficient granularity to show this additional risk reduction. While having the 24/7 capability will improve our response times and monitoring capabilities out of business hours, it does not completely eliminate the risk of a loss of supply event occurring, therefore we do not consider we could reduce the risk likelihood to 'rare'

Table 0.11: Risk rating – Option 3

Option 3	**Health & Safety**	**Environ-ment**	**Operations**	**People**	**Compliance**	**Rep & Customer**	**Finance**	**Risk**
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Low
Consequence	Minor	Minimal	Significant	Minor	Minor	Minor	Minor	
Risk Level	Negligible	Negligible	Low	Negligible	Negligible	Negligible	Negligible	

This option is consistent with our Asset Management Strategy and Risk Management Framework.

1.5.3.3 Alignment with vision objectives

Table 0.12 shows how Option 2 aligns with our vision objectives.

Table 0.12: Alignment with vision objectives – Option 2

Vision objective	Alignment
Customer Focussed - Public Safety	-
Customer Focussed – Customer Experience	Y
Customer Focussed – Cost Efficient	Y
A Leading Employer – Health and Safety	-
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	-
Operational Excellence – Benchmark Performance	-
Operational Excellence – Reliability	Y
Sustainable Communities – Enabling Net Zero	-
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	-

Option 3 would align with the *Customer Focussed* aspect of our vision, as installing additional pressure monitoring equipment helps prevent, identify and address network issues that may result in a loss of containment or loss of customer supply.

The proposed solution is also reflective of *Operational Excellence,* as the benefits for long term asset management and the avoidance of short term reactive work significantly outweigh the investment.

1.6 Summary of options assessment

Table 0.13 presents a summary of how each option compares in terms of the estimated cost, the residual risk rating, and alignment with our objectives.

Table 0.13: Comparison of options

Option	Estimated cost ($ Jan 2025)	Treated residual risk rating	Alignment with vision objectives
Option 1	No upfront capex	Moderate	Does not align with Customer Focussed, or Operational Excellence
Option 2	$0.49 million capex	Low	Aligns with Customer Focussed and Operational Excellence
Option 3	$0.99 million capex $1.0 million opex	Low	Aligns with Customer Focussed and Operational Excellence

1.7 Proposed solution

Option 3 is the recommended solution. We consider installing remote pressure monitoring at the proposed DRS and fringe sites is a cost effective and prudent risk treatment. We also consider uplifting our 24/7 monitoring capability to a level consistent with most other energy network operators is a prudent investment that will improve our emergency response capability and level of customer service for a modest and ultimately efficient cost.

1.7.1 Why is the recommended option prudent?

Option 3 is the most prudent option because it is a cost-efficient option of reducing risks to an acceptable level, consistent with stakeholder requirements and our vision, as it provides real time monitoring of pressure and alarms to:

- Allow the effective and efficient response to asset failures and the associated potential emergency events from early warning (alarms) of potential loss of supply in the event of equipment malfunction or third party damage
- Provide a "health" check of assets allowing timely diagnosis and rectification of equipment performance issues before problems arise
- Identify network issues early, such as over/under pressurisation which is increasingly important in our ageing network and allows lower cost proactive repairs to occur
- Improve safety for operational staff by reducing the need for operators to work in a confined space environment for assets located in underground pits
- Provide for real time and optimum network pressure monitoring, which will assist in minimising unaccounted for gas losses and optimising network pressures depending on season and demand conditions
- Facilitate network modelling that:
    - Helps us safely and reliably operate the network in real time
    - Informs investment decisions, in particular, assist in producing optimum network augmentation designs including pressure control facilities
    - Provides for a more cost effective and responsive monitoring solution by eliminating the need to undertake periodic data logging at fringe points and manual processing of this data

1.7.2 Estimating efficient costs

Key assumptions made in the cost estimation for this project include:

- Costs based on historical expenditure noting that these works are not new, with labour rates based on work breakdown structure of activities, and material rates based on historical costs for similar materials
- Estimates derived from contractual rates of vendors to be utilised
- Resource cost based on other similar projects ongoing at present or in previous access arrangement periods
- Original equipment manufacturer contractual rates for spares and labour that are part of our services agreements
- Fringe point and DRS installations will be treated as capex only

- The monitoring room will be established at an existing AGN-owned facility, and no new property will be purchased
- The monitoring room will be used to monitor the AGN SA, Victoria and Queensland networks, with costs for establishing and resourcing the room allocated equally between the three entities
- Costs estimates are based on desktop research and experience of similar projects, as well as initial conversations with potential vendors
- The opex component is for three additional FTE, the costs for one of which will be charged to AGN SA. The current estimate of ~$200,000 per year for a SCADA technician is based on assessment of market rates and current remuneration of comparable employees. Again, these labour costs will be subject to refinement as the project progresses and subject to market testing
- Three additional labour resources are required to ensure the monitoring room is occupied on a 24/7 basis. The 24/7 monitoring roster will be shared across 6 FTEs to allow for shift patterns and leave cover. Costs for the additional 3 FTEs will be allocated equally to AGN SA, Victoria and Queensland
- The current estimate of ~$200,000 per year for a SCADA technician is based on assessment of market rates and current remuneration of comparable employees. Again, these labour costs will be subject to refinement as the project progresses and subject to market testing
- Establishing the monitoring room will be capex. The additional resource will be a recurrent opex increase

Table 0.14 presents a breakdown of the DRS and fringe point program by cost category.

Table 0.14: Additional DRS and fringe monitoring cost estimate, by cost category, $'000 Jan 2025

Fringe monitoring	2026/27	2027/28	2028/29	2029/30	2030/31	Total
Scope	1 DRS and 2 fringe points	1 DRS and 2 fringe points	3 fringe points	2 fringe points	2 fringe points	Install SCADA at 2 DRSs and 11 fringe points
Labour – DRS	37	37				74
Labour – Fringe points	22	22	34	22	22	122
Materials – DRS	40	40				80
Materials – Fringe points	38	38	58	38	38	210
Total capex	**137**	**137**	**92**	**60**	**60**	**486**

Table 0.15 shows the monitoring room cost breakdown.

Table 0.15: Monitoring room cost estimate, by cost category, $'000 Jan 2025

Monitoring room	2026/27	2027/28	2028/29	2029/30	2030/31	Total
Materials - capex	690	-	-	-	-	690
Labour - capex	810	-	-	-	-	810
Labour (operation) – recurrent opex	600	600	600	600	600	3,000
Totex	**2,100**	**600**	**600**	**600**	**600**	**4,500**
AGN SA allocation 1/3	**700**	**200**	**200**	**200**	**200**	**1,500**

More detail on the cost breakdown is provided in Appendix A and B.

1.7.3 Consistency with the National Gas Rules

NGR 79(1)

The proposed solution is prudent, efficient, consistent with accepted and good industry practice and will achieve the lowest sustainable cost of delivering network services:

- **Prudent** – The expenditure is necessary in order to allow the effective and efficient response to asset failures and the associated potential emergency events from early warning (alarms) of potential loss of supply in the event of equipment malfunction or third party damage. Failure to address provide effective real-time telemetry at DRSs and fringe of network sites could result in leakage or isolation of a larger than necessary section of network in an emergency situation, therefore increasing the number of customers cut off from supply. The proposed expenditure is therefore consistent with that which would be incurred by a prudent service provider.
- **Efficient** – Installation of SCADA equipment at the identified locations is the most cost effective option. Costs have been based on market rates and where contractors are engaged, this will be based on a competitive process. The expenditure is therefore consistent with what a prudent service provider acting efficiently would incur.
- **Consistent with accepted and good industry practice** – Proactive telemetering is consistent with good industry practice. Reducing the risks posed by asset failures and the associated potential emergency events in a manner that balances costs and risks is also consistent with these standards.
- To **achieve the lowest sustainable cost of delivering pipeline services** – Proactive telemetering is necessary to maintain the long term integrity of the network. Failure to do so could result in additional expenditure (reactive response to pipeline or network failure). The project is therefore consistent with the objective of achieving the lowest sustainable cost of delivering services.

NGR 79(2)

The proposed capex is justifiable under NGR 79(2)(c)(i) and(ii), as it is necessary to maintain the safety and integrity of network services. A more reactive approach will inevitably lead to disruption of service and gas supply to customers.

NGR 74

The forecast costs are based on the latest market rate testing and project options consider asset management requirements as per the Asset Management Strategy. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.

Appendix A Cost estimates for additional monitoring at DRS and fringe points

DRS monitoring $'000 January 2025

Labour				
Category	**Description**	**Hours**	**Unit rate ($/unit)**	**Total unit cost ($)**
Labour - Contractor	Project Manager - External	[redacted]	[redacted]	[redacted]
Labour - Internal	Engineer - Internal	[redacted]	[redacted]	[redacted]
Labour	Draftsperson	[redacted]	[redacted]	[redacted]
Labour	Vac Truck	[redacted]	[redacted]	[redacted]
Labour	Reinstatement (150mm concrete)	[redacted]	[redacted]	[redacted]
Labour - Contractor	DRS Telemetry Labour External - Concrete + Panel Pole installation	[redacted]	[redacted]	[redacted]
Labour - Contractor	DRS Telemetry Earthing Studies	[redacted]	[redacted]	[redacted]
			[redacted]	[redacted]

Materials				
Category	**Description**	**No. items / metres**	**Unit rate ($)**	**Total unit cost ($)**
Material - Electrical	DRS Telemetry RTU Cabinet	[redacted]	[redacted]	[redacted]
Material - Electrical	DRS Telemetry Pressure Tx	[redacted]	[redacted]	[redacted]
Material - Electrical	DRS Telemetry Solar Panel	[redacted]	[redacted]	[redacted]
Material - Electrical	DRS Telemetry Field Earthing	[redacted]	[redacted]	[redacted]
Material - Electrical	DRS Telemetry Field Cabling	[redacted]	[redacted]	[redacted]
			[redacted]	[redacted]
Total DRS monitoring				**154,456.00**

Fringe monitoring $'000 January 2025

Labour				
Category	Description	No. items / metres	Unit rate ($/unit)	Total unit cost ($)
Labour - Contractor	Project Manager - External	[redacted]	[redacted]	[redacted]
Labour - Internal	Engineer - Internal	[redacted]	[redacted]	[redacted]
Labour	Draftsperson	[redacted]	[redacted]	[redacted]
Labour	Installation by 2 technicians on site	[redacted]	[redacted]	[redacted]
Labour	Vac Truck	[redacted]	[redacted]	[redacted]
			TOTAL LABOUR COST	[redacted]
Materials				
Category	Description	No. items / metres	Unit rate	Total unit cost ($)
Material - Electrical	Fringe Transmitter	[redacted]	[redacted]	[redacted]
Material - Electrical	Fringe Solar panel	[redacted]	[redacted]	[redacted]
Material - Electrical	Fringe Field Earthing	[redacted]	[redacted]	[redacted]
Material - Electrical	Fringe Field Cabling	[redacted]	[redacted]	[redacted]
Material - Electrical	Fringe RTU Cabinet	[redacted]	[redacted]	[redacted]
Total fringe monitoring			[redacted]	[redacted] **331,672.00**

Appendix B Cost estimate for monitoring room

The current costs estimate is based on desktop analysis and experience of similar projects. Initial conversations have been held with potential vendors, but no detailed quotes or specification have been developed at the time of preparing this regulatory business case. A more detailed cost estimate will be available in late 2025 or early 2026. Costs for setting up the monitoring room will be capitalised, while the ongoing uplift in FTE resourcing will be recurrent opex. Costs are to be allocated equally between the three AGN network entities that will benefit from the 24.7 monitoring capability.

Monitoring room establishment – capex $'000 January 2025

Capex item	Description	Basis of estimate	Estimated cost $'000	AGN SA allocation $'000
Planning and design	Engage third party vendor to help develop monitoring strategy and 24/7 monitoring requirements. Project planning and refining monitoring room specification/costs.	Quote from external consultant	420	140
Project management	Dedicated manager to coordinate delivery of the project	High level market testing. Comparison with similar project management roles within AGN	300	100
Equipment	• SCADA systems • Data servers and storage • Use interface and control panels • Communication systems • Alarm systems • Ergonomic work station, desks and chairs • Security access / lockable doors • Procedures development / standardisation • Training materials	Desktop research and comparison against historical costs. A detailed specification has not yet been developed and will be refined once we enter the planning and design phase. The equipment costs are a reasonable estimate using the best information available at the time of preparing this business case.	600	200
Room fit out	Labour and materials for renovating the room and connecting the necessary communications, IT and OT.	Desktop research and experience of similar projects at other network businesses. Assume 50% split labour v materials.	180	60
Total capex			**1,500**	**500**

Monitoring room 24/7 resourcing – opex $'000 January 2025

Opex item	Description	Basis of estimate	Estimated recurrent annual cost $'000	AGN SA annual allocation $'000
FTE resources	6 FTE required to ensure 24/7 monitoring and cover shift patterns/leave. 3 FTE currently employed to conduct monitoring, with costs already in our opex base year. A recurrent increase for 3 FTE required.	High level market testing. Comparison with similar SCADA technician roles within AGN	600	200
Total opex			**600**	**200**

Appendix C Comparison of risk assessments

Untreated	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Moderate (not ALARP)
Consequence	Significant	Minimal	Significant	Minor	Minor	Minor	Minor	
Risk Level	Moderate	Negligible	Moderate	Low	Low	Low	Low	

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Moderate (Not ALARP)
Consequence	Significant	Minimal	Significant	Minor	Minor	Minor	Minor	
Risk Level	Moderate	Negligible	Moderate	Low	Low	Low	Low	

Option 2	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Low
Consequence	Minor	Minimal	Significant	Minor	Minor	Minor	Minor	
Risk Level	Negligible	Negligible	Low	Negligible	Negligible	Negligible	Negligible	

Option 3	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Low
Consequence	Minor	Minimal	Significant	Minor	Minor	Minor	Minor	
Risk Level	Negligible	Negligible	Low	Negligible	Negligible	Negligible	Negligible	

SA213 – Vehicles, plant and equipment

1.1 Project approvals

Table 0.1: SA213 – Project approvals

Prepared by	Matthew Haynes – Access Arrangement Engineer
Reviewed by	Robin Gray – Manager Operations SA
Approved by	Jason Morony – Head of Networks Operations

1.2 Project overview

Table 0.2: SA213 – Project overview

Description of the problem / opportunity	A standard suite of vehicles, plant and equipment (P&E) is required on an ongoing basis to enable our workforce to conduct repair and alteration work on the pipelines and other gas asset infrastructure. This equipment is used for activities such as flow stopping, underground asset detection, gas detection, welding and fusion, and pressure testing. As existing vehicles, plant and equipment age, they must be replaced before they become unfit for purpose due to wear or obsolescence. Technological advancements, changes in standards and internal practices also drive the need for new types and categories of equipment. There are three key categories of expenditure: • **Vehicles** – Trucks and other vehicles, which are replaced as and when they become unsafe or they become inefficient to continue to use and maintain them • **Small P&E** – General (small value) replacement and new plant and equipment items that require ongoing purchase each year • **High pressure flow stopping** – Stopple equipment, which is used to flow stop high pressure steel pipelines, enabling the safe isolation of the gas supply and controlled gas release Ongoing proactive investment in new and replacement vehicles, plant and equipment helps create a safe working environment for all employees and contractors by providing plant, tools and equipment that are in good working order, fit for purpose and tested/calibrated (as required) to the required standard. This business case considers the cost of continuing the current proactive replacement of vehicles, plant and equipment, or whether it would be more prudent to move to a reactive 'replace on failure' approach.
Untreated risk	As per risk matrix = High
Options considered	• **Option 1** – Cease the proactive purchase of all plant and equipment, replace plant and equipment reactively as and when equipment fails (no upfront capital cost) • **Option 2** – Continue to proactively replace plant and equipment as and when it becomes unsafe or inefficient to continue using existing equipment ($5.0 million) As there are no reasonable and practicable alternatives to the ongoing use of these plant and equipment items, no other options have been considered in this business case.
Proposed solution	Option 2 is the proposed solution. We will continue with the current practice of procuring and replacing appropriate vehicles, plant and equipment necessary to install, repair and maintain natural gas assets.

<table>
<tr><td></td><td>We will replace out-of-service hot tap and stoppling equipment, as well as replacing the anticipated number of vehicles that will become unsafe or inefficient to continue to use and maintain during the next five years. We will also purchase new equipment based on increasing internal labour requirements.
Option 1 would lead to safety and reliability issues in the event of equipment failure during either planned or emergency situations, and as such, this option is not considered viable.</td></tr>
<tr><td>Estimated cost</td><td>The forecast direct cost (excluding overhead) during the next five-year period (July 2026 to June 2031) is $5.0 million.
<table>
<tr><th>$’000 Jan 2025</th><th>26/27</th><th>27/28</th><th>28/29</th><th>29/30</th><th>30/31</th><th>Total</th></tr>
<tr><td>Vehicles, plant & equipment</td><td>871</td><td>994</td><td>1,242</td><td>1,455</td><td>432</td><td>4,994</td></tr>
</table></td></tr>
<tr><td>Basis of costs</td><td>All costs in this business case are expressed in real unescalated dollars at January 2025 unless otherwise stated.</td></tr>
<tr><td>Alignment to our vision</td><td>This project aligns with our vision to be <i>Customer Focussed</i> and <i>A Leading Employer</i>, as it will lead to employee and public safety standards being maintained. Having fit for purpose vehicles, and P&E readily available will also enable us to maintain reliability levels and respond quickly during an emergency.
This option also reflects <i>Operational Excellence</i>, as proactive purchase of vehicles and P&E as part of a scheduled ongoing program is considerably more cost effective than purchasing assets on a reactive basis. We also seek to replace vehicles and P&E with new and/or improved technologies, where they allow us to operate more efficiently (without compromising safety).</td></tr>
<tr><td>Consistency with the National Gas Rules (NGR)</td><td>NGR 79(1) – The proposed solution is consistent with good industry practice, several practicable options have been considered, and market rates have been tested to achieve the lowest sustainable cost of providing this service.
NGR 79(2) – The proposed capex is justifiable under NGR 79(2)(c)(i), as it is necessary to maintain and improve the safety of services.
NGR 74 – The forecast costs of vehicles and P&E are based on the latest market estimates, costs and operational experience. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.</td></tr>
<tr><td>Treated risk</td><td>As per risk matrix = Moderate (ALARP)</td></tr>
<tr><td>Stakeholder engagement</td><td>We are committed to operating our networks in a manner that is consistent with the long-term interests of our customers. To facilitate this, we conduct regular stakeholder engagement to understand and respond to the priorities of our customers and stakeholders. Feedback from stakeholders is built into our asset management considerations and is an important input when developing and reviewing our expenditure programs.
Our customers have told us their top three priorities are price/affordability, reliability of supply, and maintaining public safety. They also told us they expect us to deliver a high level of public safety and are satisfied that this is current practice.
The ongoing proactive purchase of vehicles and P&E will help us maintain public safety and reliability of supply and is therefore consistent with the practices customers have told us they value.</td></tr>
<tr><td>Other relevant documents</td><td>• Attachment 9.1: Safety, Reliability, Maintenance and Technical Management Plan
• Attachment 9.3: Asset Management Plan
• Attachment 9.6: Procurement Policy & Procedure
• Attachment 9.10: Unit Rates Report
• Attachment 9.11: Risk Management Framework</td></tr>
</table>


R.McELROY

1.3 Background

The SA natural gas distribution networks include approximately 200 km of steel transmission pressure (TP) pipelines and 8,500 km of distribution pipelines, which deliver gas to over 485,000 consumers.

Our operational groups (Asset Protection, Planned Maintenance, Systems Monitoring and Field Operations) use a variety of vehicles plant and equipment (P&E) and small capital items to undertake planned and reactive works to maintain and extend the network.

These assets periodically require upgrading and replacing, for the following reasons:

- General wear and tear, as the equipment becomes unserviceable and ongoing maintenance costs increase
- Community expectation that equipment is fit for purpose and meets good practice standards with respect to emissions of noise, dust, etc.
- To upgrade to current technology, ensuring efficient work practices and minimisation of errors (e.g. digital read outs on equipment)
- To accommodate increases in APA internal labour headcount
- To minimise the manual handling component of activities, reducing both the likelihood and consequence of workplace injuries
- To mitigate the risk of injury to personnel working in high risk situations such as live work on leak repairs

Vehicles and P&E comprises three broad categories of items, described in the following sections.

1.3.1 Vehicles

We have a fleet of 20 service trucks of various configurations used to support network repair and alteration activities by internal staff. Most of these trucks are coming to the end of their 12-year technical life during the current AA period (2021 - 2026). However we have deferred some replacements based on their performance and condition, which has enabled us to extend their lives by several years.

During the next five-year period (2026 – 2031) it is proposed to continue with the same policy of the assessment and replacement of vehicles that have reached the end of their 12-year technical life as necessary. As part of ongoing assessments, the current stock of vehicles is not expected to be able to be retained due to their poor condition.

As well as replacing end of life vehicles, we plan to purchase two new vehicles. The two new vehicles are a vacuum truck and trailer. Vacuum truck excavation is recognised as standard industry practice due to its safety and efficiency advantages. Safety is paramount in excavation work, and vacuum trucks minimise these risks. Traditional excavation methods often involve heavy machinery that can inadvertently damage underground utilities, posing hazards to workers and the environment. Vacuum excavation is now tried and tested in South Australia and uses high-pressure water to safely expose other utilities without physical contact, reducing the likelihood of utility strikes and associated hazards.

Vacuum truck excavation also allows for more precise digging, which is particularly beneficial in congested urban areas where accuracy is crucial. The process can be faster than traditional methods as it eliminates the need for manual digging and reduces downtime associated with utility damage repairs.

As *A Leading Employer* and prudent asset manager, we have a commitment to replace vehicles that are in poor condition and represent a safety and/or reliability risk.

1.3.2 Small P&E

Various types of small P&E are required for the network activities including:

- Underground asset detection – identification and location of underground assets prior to, and during, excavation activities
- Gas detection – location and classification of asset gas leaks as well as accurate assessment of gas levels during commissioning and decommissioning activities
- Polyethylene (PE) welding and fusion – welding on fittings and joints during operational activities
- Pressure testing – testing to ensure compliance with different operating pressures in accordance with AS/NZ S4645 and AS/NZS 2885 pressure requirements

Small P&E are replaced and upgraded on an ongoing basis. The rate of replacement depends on a variety of factors, including the type of equipment, degree of use, harshness of service, technological obsolescence and increases in internal crew headcount. However, the amount of investment required has typically been relatively consistent over time, and as such, a historical expenditure trend is commonly used to guide estimates of future expenditure.

1.3.3 High pressure flow stopping equipment

Stopple equipment is used for planned and unplanned maintenance on the network. It is used to stop the flow of gas on high pressure steel pipelines, enabling the safe isolation of the gas supply and a controlled release of gas. This equipment is required to be replaced to ensure we can continue to isolate, repair and tie into steel pipelines of all sizes safely for planned maintenance and reactive emergencies.

New stopple equipment for isolating DN100 to DN200 steel pipelines was purchased during the current five-year period (2021 – 2026) to replace equipment that was over 40 years old. Stopple equipment outside of this size range is still over 40 years old so we are proposing to replace equipment for these steel pipe sizes during the next five years.

1.4 Risk assessment

Risk management is a constant cycle of identification, analysis, treatment, monitoring, reporting and then back to identification (as illustrated in Figure 0.10). When considering risk and determining the appropriate mitigation activities, we seek to balance the risk outcome with our delivery capabilities and cost implications. Consistent with stakeholder expectations, safety and reliability of supply are our highest priorities.

Our risk assessment approach focuses on understanding the potential severity of failure events associated with each asset and the likelihood that the event will occur. Based on these two key inputs, the

Figure 0.1: Risk management principles

risk assessment and derived risk rating then guides the actions required to reduce or manage the risk to an acceptable level.

Our risk management framework is based on:

- AS/NZS ISO 31000 Risk Management – Principles and Guidelines
- AS 2885 Pipelines-Gas and Liquid Petroleum
- AS/NZS 4645 Gas Distribution Network Management

The *Gas Act 1997* and *Gas Regulations 2012*, through their incorporation of AS/NZS 4645 and the *Work Health and Safety Act 2012*, place a regulatory obligation and requirement on AGN to reduce risks rated high or extreme to low or negligible as soon as possible (immediately if extreme). If it is not possible to reduce the risk to low or negligible, then we must reduce the risk to as low as reasonably practicable (ALARP).

When assessing risk for the purpose of investment decisions, rather than analysing all conceivable risks associated with an asset, we look at a credible, primary risk event to test the level of investment required. Where that credible risk event results in a risk event rated moderate or higher, we will consider investment to reduce the risk.

Seven consequence categories are considered for each type of risk:

1. **Health & safety** – Injuries or illness of a temporary or permanent nature, or death, to employees and contractors or members of the public
2. **Environment (including heritage)** – Impact on the surroundings in which the asset operates, including natural, built and Aboriginal cultural heritage, soil, water, vegetation, fauna, air and their interrelationships
3. **Operational capability** – Disruption in the daily operations and/or the provision of services/supply, impacting customers
4. **People** – Impact on engagement, capability or size of our workforce
5. **Compliance** – The impact from non-compliance with operating licences, legal, regulatory, contractual obligations, debt financing covenants or reporting / disclosure requirements
6. **Reputation & customer** – Impact on stakeholders' opinion of AGN, including personnel, customers, investors, security holders, regulators and the community
7. **Financial** – Financial impact on AGN, measured on a cumulative basis

Our Risk Management Framework, including definitions, has been provided in Attachment 9.11.

Failure of vehicles, P&E can lead to a number of risks and risk events, depending on what type of asset fails (or is unavailable). Examples include:

- Failure to have appropriate gas detectors to adequately detect and classify leaks could result in fatalities and extensive property damage, especially if gas accumulates under buildings and is exposed to an ignition source

- Failure to locate underground electricity cables could result in fatality. Many high voltage cables have been hit by operators while undertaking normal activity despite the use of "before you dig". Often plans are incorrect or incomplete and appropriate equipment is the last line of defense against electrocution and a major disruption to power supply and telecommunications

- Failure to review and purchase improved technology in excavation equipment such as vacuum excavation and air pick technology can result in fatality or significant workplace injury due to damage to either a gas or electrical asset while using an excavator or mechanical tools such as a shovel or crowbar

- Failure to protect against manual handling risks in general can result in significant workplace injuries, especially to backs (as evidenced by the history of workplace injuries), primarily to field workers performing normal duties, including driving, digging, carrying and lifting

- Failure to provide a safe work environment around and within confined spaces could lead to fatality through asphyxiation or inadequate retrieval in a medical emergency

- Failure to provide correct storage of material stocks and tools and equipment can result in hazardous store situations. Good housekeeping and a tidy workplace contribute to a fit for purpose working environment for personnel, minimising health and safety incidents

There are also potential high financial risks such as exposure to legislative penalties for failing to provide a safe place of work and litigation if injuries are incurred.

Additionally, there is a risk to efficiency if available and emerging technology is not pursued to address specific network issues and opportunities. For example:

- Private properties increasingly do not provide appropriate access to gas infrastructure. Gas detection improvements in technology portable gas detectors with infrared enables gas survey work to be undertaken more efficiently

- Electrical cable is not always installed to electrical standards and often embedded in concrete paths around the customer's house. Underground radar technology can be used to improve the accuracy of locating underground cable prior to mechanical excavation

The primary risk event being assessed is that the failure or unavailability of fit for purpose vehicles, plant and equipment can lead to serious injury or fatality in certain circumstances.

The untreated risk[20] rating is presented in Table 0.9.

Table 0.3: Risk assessment – untreated risk

Untreated risk	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minor	Significant	Significant	Significant	Significant	Significant	
Risk Level	High	Low	Moderate	Moderate	Moderate	Moderate	Moderate	

1.5 Options considered

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[20] Untreated risk is the risk level assuming there are no risk controls currently in place. Also known as the 'absolute risk'.

The options considered are:

- **Option 1** – Move to reactive replacement
- **Option 2** – Continue to proactively replace plant and equipment as and when it becomes unsafe or inefficient to continue using existing equipment

1.5.1 Option 1 – Move to reactive replacement

This option is to discontinue the current practice of proactively keeping vehicles, plant and equipment fit for purpose and up to date. We will continue to use existing vehicles, stoppling equipment and P&E until each item is no longer able to be used due to obsolescence, breakdown or loss of function. Once this equipment becomes unusable or is no longer able to be maintained, it would need to be replaced on a reactive basis.

1.5.1.0 Advantages and disadvantages

The primary benefit of this option is the deferral of capex to later years.

There are significant disadvantages to this option, including:

- Increasing wear and tear on vehicles, plant and equipment, with assets not able to be maintained in an appropriate manner, and therefore a gradually degrading and reducing equipment pool
- Increased operating expenditure (opex) for additional maintenance activities to 'keep vehicles, tools and equipment going'
- Loss of productivity, loss of purchasing power, less economies of scale and increased timeframe pressures during the procurement process
- Sharing of functional equipment between operational crews, resulting in decreased productivity associated with inefficient operation
- Additional costs could be expected to be incurred under a reactive replacement scenario, including costs associated with the potential requirement to stop work and then restart once new assets have been procured

1.5.1.1 Cost assessment

There would be no additional upfront capital costs with this option.

1.5.1.2 Risk assessment

The risk outcome of this option is high. This is driven by health and safety risks, because if appropriate tools and equipment for the tasks performed are not provided then it will expose operators, customers and the surrounding environment to health and safety risks.

The residual risk remains unchanged from the untreated risk (see Table 0.4).

Table 0.4: Risk assessment – Option 1

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minor	Significant	Significant	Significant	Significant	Significant	
Risk Level	High	Low	Moderate	Moderate	Moderate	Moderate	Moderate	

1.5.1.3 Alignment with vision objectives

Table 0.12 shows how Option 1 aligns with our vision objectives.

Table 0.5: Alignment with vision – Option 1

Vision objective	Alignment
Customer Focussed – Public Safety	N
Customer Focussed – Customer Experience	N
Customer Focussed – Cost Efficient	N
A Leading Employer – Health and Safety	N
A Leading Employer – Employee Experience	N
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	-
Operational Excellence – Benchmark Performance	N
Operational Excellence – Reliability	-
Sustainable Communities – Enabling Net Zero	-
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	N

Option 1 would not align with our objectives of being *Customer Focussed* or *A Leading Employer*, due to increased employee health and safety risks as well as public safety risks.

Failing to provide our employees with fit for purpose vehicles, plant and equipment in a timely manner does not reflect *Operational Excellence*, as we would likely incur a premium if equipment is required in an emergency, as well as running the risk of supply interruption if replacement parts are not accessible quickly (for example emergency gas).

There is also potential for financial risks such as exposure to legislative penalties for failing to provide a safe place of work and litigation if injuries are incurred.

1.5.2 Option 2 – Proactively replace vehicles and P&E as and when it becomes unsafe or inefficient

Under this option we would continue the current proactive replacement strategy. This would involve:

- Replacing an estimated 75% of vehicles that will reach their technical life during the next five-year period
- Continuing to purchase small plant and equipment items at a level consistent with historical trend

- Replacing of out-of-service hot tap and stoppling equipment during the next five-year period (July 2021 to June 2026)

1.5.2.0 Advantages and disadvantages

This option has the following benefits:

- Productivity will be maintained or improved, as newer tools and emerging technologies may promote more efficient ways of carrying out the work
- Health and safety performance will be maintained by making sure we continue to utilise current technologies, equipment design and work methodologies
- Procurement of items can be effectively and efficiently planned and executed, for example purchasing tools in bulk where applicable to capture volume discounts, or competitively tendering larger items
- It is consistent with good industry practice
- We will continue to fulfil our obligations to maintain a safe working environment and reduce the impact of operations on the public

1.5.2.1 Cost assessment

The estimated direct capital cost of this option is $5.0 million as showed in Table 0.9.

Table 0.6: Cost assessment – Option 2, $ '000 January 2025

	2026/27	2027/28	2028/29	2029/30	2030/31	Total
Vehicles	580	580	580	944	246	**2,930**
Small P&E	291	414	362	311	186	**1,564**
High Pressure Flow Stopping	-	-	300	200	-	**500**
Total	**871**	**994**	**1,242**	**1,455**	**432**	**4,994**

Each of these categories is discussed further in the following sections.

1.5.2.1.1 Vehicles

Expenditure on fleet vehicles is a continued investment at long-term sustainable replacement and growth rates. While fifteen vehicles reached the end of their technical life during previous periods, their replacement is based on individual assessment of their operability on an ongoing basis. This means that their actual operable life can be extended past their technical design life if safe and efficient to do so.

Despite this, even with our good maintenance practices maximising the asset life, it is expected that the majority of vehicles will require replacement in the next five-year period.

Table 0.7: Vehicle replacement forecast

Vehicle	Number	Type	Rate ($`000)	Total
Pantech trucks	[redacted]	Replacement	[redacted]	$1,080,000
Tippers trucks	[redacted]	Replacement	[redacted]	$660,000
Excavator & Trailer	[redacted]	Replacement	[redacted]	$270,000
Excavator	[redacted]	Replacement	[redacted]	$120,000
Workshop / Store Forklift	[redacted]	Replacement	[redacted]	$62,500
Excavation Vacuum Truck medium	[redacted]	New	[redacted]	$614,000
Excavation Vacuum Trailer - Light Duty	[redacted]	New	[redacted]	$123,000
Total	**15**			**$2,929,500**

1.5.2.1.2 Small P&E

Continued investment in small plant and equipment will allow for maintaining the quantity and performance of plant, equipment and tools. This includes an expectation that the functionality of some equipment will improve to provide a greater range of applicability and therefore greater risk reduction for the same cost.

Table 0.8: Small P&E forecast

Equipment	Number	Unit cost	Total cost
High Press Grease Guns Regional	[redacted]	[redacted]	$20,000
Electrofusion Units Battery operated	[redacted]	[redacted]	$60,000
Ipads replacement and new	[redacted]	[redacted]	$27,000
CP Data Loggers	[redacted]	[redacted]	$30,000
Replacement Roller Doors KP	[redacted]	[redacted]	$40,000
Gas Detector Replacement	[redacted]	[redacted]	$450,000
LPG Gas Detector Replacement	[redacted]	[redacted]	$30,000
SCBA for field Crews	[redacted]	[redacted]	$112,000
Laser Gas detectors	[redacted]	[redacted]	$400,000
Pipe Locators	[redacted]	[redacted]	$96,000
Pantech Generator	[redacted]	[redacted]	$31,500
Drills Battery Road surface	[redacted]	[redacted]	$13,650
Tripod Battery	[redacted]	[redacted]	$6,000
General Tools replacement	[redacted]	[redacted]	$210,000
Replacement Fencing for above ground sites	[redacted]	[redacted]	$20,000
Spy Holiday Detector	[redacted]	[redacted]	$18,000
Total			**$1,564,150**

1.5.2.1.3 High pressure flow stopping equipment

During the next five-year period we will replace the remaining critical high-pressure flow stopping equipment that has reached its end of life. The cost estimate for this equipment is $500,000.

1.5.2.2 Risk assessment

This option reduces the risk from high to moderate (ALARP). This is due to a change in the likelihood of the risk event from unlikely to remote. The residual risk outcomes are shown in Table 0.9.

Table 0.9: Risk assessment – Option 2

Option 2	**Health & Safety**	**Environ-ment**	**Operations**	**People**	**Compliance**	**Rep & Customer**	**Finance**	**Risk**
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Moderate (ALARP)
Consequence	Major	Minor	Significant	Significant	Significant	Significant	Significant	
Risk Level	Moderate	Negligible	Low	Low	Low	Low	Low	

1.5.2.3 Alignment with vision objectives

Table 0.6 shows how Option 2 aligns with our vision objectives.

Table 0.10: Alignment with vision – Option 2

Vision objective	**Alignment**
Customer Focussed – Public Safety	Y
Customer Focussed – Customer Experience	Y
Customer Focussed – Cost Efficient	-
A Leading Employer – Health and Safety	Y
A Leading Employer – Employee Experience	Y
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	-
Operational Excellence – Benchmark Performance	Y
Operational Excellence – Reliability	Y
Sustainable Communities – Enabling Net Zero	-
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	-

Option 2 would align with our objective to be *Customer Focussed* and *A Leading Employer*, as having fit for purpose vehicles, plant and equipment will allow us to maintain employee and public safety standards. Having fit for purpose vehicles, plant and equipment readily available will also enable us to maintain reliability levels and respond quickly during an emergency.

This option also reflects *Operational Excellence*, as proactive purchase of vehicles, plant and equipment as part of a scheduled ongoing program is considerably more cost effective than purchasing it on a reactive basis. We also seek to replace vehicles, plant and equipment with new and/or improved technologies, where that new technology allows us to operate more efficiently (without compromising safety). Additionally, this option mitigates potential financial risks associated with unsafe workplace legislative penalties or litigation.

1.6 Summary of costs and benefits

Table 0.15 presents a summary of how each option compares in terms of the estimated cost, the residual risk rating, and alignment with our objectives.

Table 0.11: Comparison of options

Option	**Estimated cost**	**Treated residual risk rating**	**Alignment with vision objectives**

Option 1 – Reactive replacement	No upfront capex	High	Does not align with *Customer Focussed, A Leading Employer* or *Operational Excellence*
Option 2 – Proactive replacement	$5.0 million	Moderate (ALARP)	Aligns with *Customer Focussed, A Leading Employer* and *Operational Excellence*

1.7 Recommended option

The proposed solution is Option 2. This option provides for necessary expenditure to replace aged and damaged vehicles, tools and equipment in each year of the next five-year period.

1.7.1 Why is the recommended option prudent?

Option 2 is recommended because:

- Vehicles, small plant and equipment and stoppling equipment are required for maintaining the gas network. This option ensures existing equipment is appropriate and up to date and that new equipment technology is reviewed and utilised where appropriate to improve safety and efficiency
- It is the only option that reduces risks to an acceptable level (ALARP). Option 1 could result in safety and reliability impacts in the event of equipment failure during either planned or emergency situations, and as such, this option is not considered prudent
- Additional costs could be expected to be incurred under a reactive replacement scenario, including costs associated with the potential requirement to stop work and then restart once new vehicles, plant and equipment items have been procured
- It is consistent with stakeholder requirements and our vision
- The delivery of the scope of works is achievable in the time frame envisaged

1.7.2 Estimating efficient costs

The cost estimate for this program of work has been developed based on the following assumptions:

- The cost of each of the remaining vehicles at the end of their technical design life has been determined based on a combination of quotes and recent actual purchase costs
- The vehicle unit rates reflect an upsurge in the unit costs of vehicles post COVID-19
- Each of the forecasts have been developed as a bottom up build with a top down challenge to ensure alignment of forward forecast with actual expenditures
- The estimate for the flow stopping equipment is based on a recently obtained supplier quotation and previous purchases
- Replacement equipment is sourced through various suppliers and is subject to our standard procurement procedures
- Quotes are collected and reviewed for consistency with operational requirements (e.g. compatibility with other vehicles, plant and equipment)

1.7.3 Consistency with the National Gas Rules

In developing these forecasts, we have had regard to NGR 79 and 74. With regard to all projects, and as a prudent asset manager, we give careful consideration to whether capex is conforming from a number of perspectives before committing to capital investment.

NGR 79(1)

The proposed solution is prudent, efficient, consistent with accepted and good industry practice and will achieve the lowest sustainable cost of delivering pipeline services:

- **Prudent** – The expenditure is necessary to ensure there are adequate and appropriate tools, plant and equipment necessary to perform the required functions. The expenditure will allow the continued safe, reliable supply of gas to consumers, services to be maintained and improved and the integrity of the network to be maintained.

- **Efficient** – Cost estimates are based on a mix of current contract rates, third-party estimates and historical spend, and will follow robust procurement practices. The estimate allows for maintaining the quantity of vehicles, plant and equipment at current levels with the expectation that the functionality of some equipment will improve to provide a greater range of applicability and therefore greater risk reduction for the same cost. On that basis, we consider the expenditure to be efficient.

- **Consistent with accepted and good industry practice** – The vehicles, tools and equipment already in use and planned under this program are an essential part of performing the work. Equipment such as large diameter squeeze off and stoppling equipment are essential for emergency response.

- To **achieve the lowest sustainable cost of delivering pipeline services** – Vehicles, plant and equipment are necessary to deliver pipelines services in a safe and cost effective manner, and there is no suitable alternative to this investment. The chosen option is therefore consistent with the objective of achieving the lowest sustainable cost of service delivery.

NGR 79(2)

The proposed capex is justifiable under NGR 79(2)(c)(i), as it is necessary to maintain and improve the safety of services. The absence of appropriate and reliable vehicles, plant and equipment would mean that gas services could not be maintained safely, resulting in risk to both maintenance personnel and the general public.

NGR 74

The forecast costs are based on the latest market rate testing and project options consider the asset management requirements as per the Asset Management Strategy. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.

Appendix A Comparison of risk assessments

Untreated risk	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minor	Significant	Significant	Significant	Significant	Significant	
Risk Level	High	Low	Moderate	Moderate	Moderate	Moderate	Moderate	

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Major	Minor	Significant	Significant	Significant	Significant	Significant	
Risk Level	High	Low	Moderate	Moderate	Moderate	Moderate	Moderate	

Option 2	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Moderate (ALARP)
Consequence	Major	Minor	Significant	Significant	Significant	Significant	Significant	
Risk Level	Moderate	Negligible	Low	Low	Low	Low	Low	

Appendix B Examples of equipment and improving technology

Examples of equipment items purchased during the current AA period include:

- Self-contained breathing apparatus for personnel working on leak repair or working in confined spaces
- Large diameter PE stopple equipment (for emergency response and routine activity)
- PE squeeze-off equipment (for emergency response and routine activity)
- Low noise power generators to alleviate noise created during 24/7 activity
- Compaction tools
- DCVG equipment
- Concrete cutting devices
- Underground cable location equipment
- Hydraulic flange spreaders

Recent examples of such continuous improvement include lockring equipment and fittings, odorising detection equipment and new corrosion detection and monitoring equipment to improve the integrity of the assets.

SA219 – Concordia supply

1.1 Project approvals

Table 0.1: Business case SA219 – Project approvals

Prepared by	Matthew Haynes – AA Engineer David Holden – Business Development Manager
Reviewed by	Martijn Vlugt – Manager Asset Planning
Approved by	Michael Iapichello – Head of Engineering and Planning Nick Kafamanis – Head of Networks Capital Delivery

1.2 Project overview

Table 0.2: Business case SA219 – Project overview

Description of the problem / opportunity	Greenfield growth in Concordia, a rural area north of Adelaide, was originally forecast to commence during the current period (2021-26). However, due to the co-location of energy, water and wastewater services, and the delay in particular with approvals for water and sewer works this has not yet occurred. [redacted], the project developer, has confirmed that the development is still intended to be supplied by the gas network and the new date by which the Concordia area will need to be fully reticulated is 2029. Plans for the development of the Concordia growth area have not changed from the initial master plan. The consistency of the plan over this time increases our confidence that the project will progress as initially intended, as opposed to being redesigned causing further delays. Concordia will form a natural extension of the existing Gawler township and is forecast to result in an additional 10,000 connections to the South Australian gas distribution network over the next 25 years. The construction of the Gawler Gate Station and connection to the SEA Gas Transmission pipeline reinforced the Gawler high pressure network sufficiently for us to supply Concordia through that network, without the need for a direct connection to the Gawler Gate Station. This business case considers technical solutions for the supply of the Concordia development, and the cost and benefits of conducting the work as part of a greenfield project (rather than brownfieldss). This business case does not include the costs associated with reticulation which is covered by growth capex.
Options considered	• **Option 1** – Supply Concordia via Gawler high pressure network connected near the Gawler Gate Station ($4.3 million) • **Option 2** – Supply Concordia via the Gawler high pressure network connected near Roseworthy ($8.2 million) • **Option 3** – Do not supply Concordia as a greenfields development (no upfront cost)
Proposed solution	Option 1 is the proposed solution. Connecting to the existing Gawler network near the Gawler Gate Station will enable new homes and businesses to connect immediately and at a lower overall cost than if the Concordia development were connected near Roseworthy, or if it was to be constructed as a brownfield project. Developers and potential customers have expressed a desire for gas in the area, and there is sufficient evidence that the forecast number of connections will arise if the necessary gas infrastructure is installed. Connecting Concordia to the existing Gawler network near the Gawler Gate Station (Option 1) is more efficient than a connection to the Gawler network further north near Roseworthy (Option 2), as it takes advantage of the new SEA

Gas connection for Gawler, which is necessary to address existing pressure issues in the Gawler and Willaston networks and reduces flow restrictions due to smaller intermediary pipelines.

Option 3 (not supplying Concordia) is not recommended, as the opportunity for new connections and incremental revenue will be foregone. Increasing the number of gas connections benefits all customers connected to the distribution network, as it means the total network fixed costs are spread across a larger customer base.

Estimated cost

The forecast direct cost (excluding overhead) during the next five-year period (July 2026 to June 2031) is $4.3 million.

$'000 Jan 2025	26/27	27/28	28/29	29/30	30/31	Total
Concordia supply	-	4,340	-	-	-	**4,340**

Basis of costs

All costs in this business case are expressed in real unescalated dollars at January 2025 unless otherwise stated.

Net present value (NPV) assessment

Option 1 achieves a positive NPV at 20 years and $12.5 million at 30 years. By comparison, Option 2 achieves a positive NPV at 23 years and $8.5 million over 30 years.

Alignment to our vision

This investment aligns with being *Customer Focussed,* as it will ensure new homes and business in Concordia will have access to natural gas supply.

The proposed solution reflects *Operational Excellence*, as it returns a positive NPV within 20 years, and increases the number of connections to the network, thereby helping spread costs across a larger customer base.

Consistency with the National Gas Rules (NGR)

NGR 79(1) – The proposed option is prudent as there is evidence of natural gas demand in the area and ongoing growth over the next 30 years. Installing gas infrastructure as part of a greenfields development is two to three times more cost efficient than brownfields developments and historically has resulted in a larger penetration rate (>80%). The increased number of connections means total network costs are spread over a larger customer base, which helps achieve the lowest sustainable cost of providing services.

NGR 79(2) – The proposed capex is justifiable under NGR 79(2)(b), as the present value of the expected incremental revenue to generated as a result of the network expansion into Concordia (including the cost of reticulation) exceeds the present value of the capital expenditure, returning a positive NPV after 20 years.

NGR 74 – The forecast costs and are based on the latest market rate testing and estimated demand in the region is based on evidence provided by developers and prospective customers. We have also used precedent from similar network expansions to inform the forecast number of connections and penetrations rates. An NPV assessment has been conducted for the proposed solution. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.

Stakeholder engagement

We are committed to operating our networks in a manner that is consistent with the long-term interests of our customers. To facilitate this, AGN conducts regular stakeholder engagement to understand and respond to the priorities of our customers and stakeholders. Feedback from stakeholders is built into our asset management considerations and is an important input when developing and reviewing our expenditure programs.

Our customers have told us their top three priorities are price/affordability, reliability of supply, and maintaining public safety. They also told us they expect AGN to deliver a high level of public safety.

Making natural gas available to new customers in Concordia is consistent with our customers' priorities. Increasing the number of connections and maintaining the viability of natural gas as a complementary (and alternative) energy source to electricity helps spread network costs and keep gas affordable. More significantly, customers continually tell us during our engagements that they value natural gas and see it as an important part of the energy mix. It is

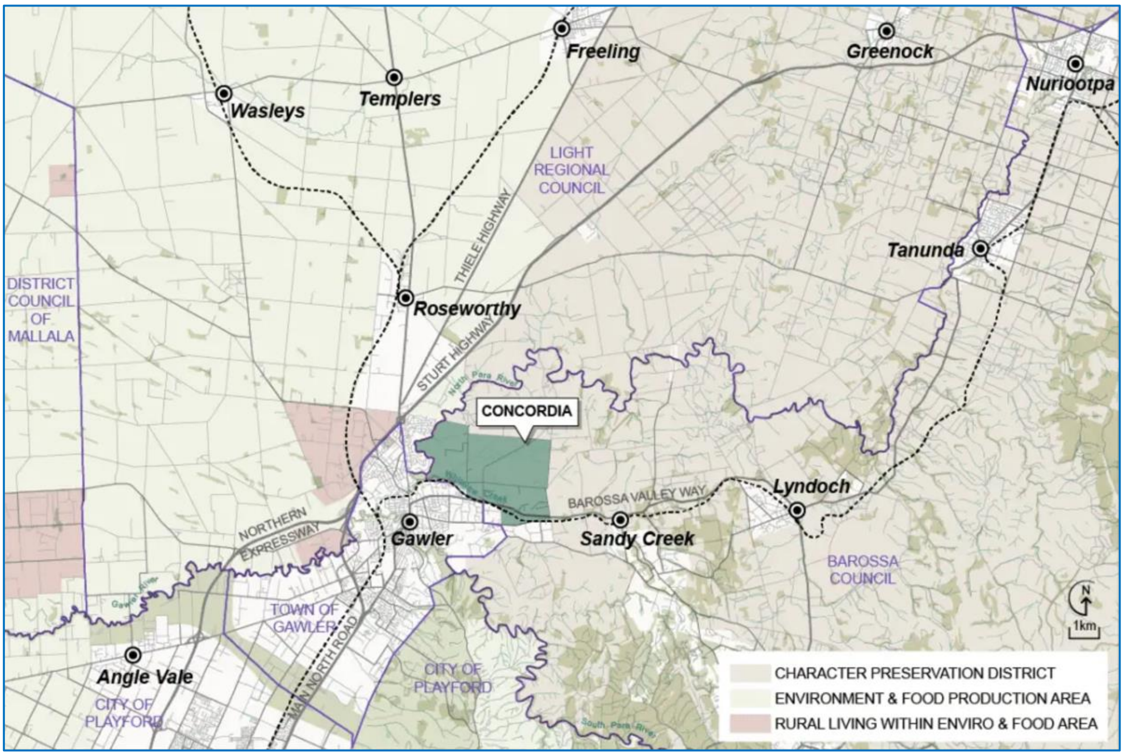
	therefore in keeping with customer expectations for us to expand the network to areas where there is a clear demand for natural gas.
Other relevant documents	• Attachment 9.3: Asset Management Plan • Attachment 9.6: Procurement Policy & Procedure • Attachment 9.10: Unit Rates Report • Attachment 9.11: Risk Management Framework

1.3 Background

The northern suburbs of metropolitan Adelaide are a major residential growth area in South Australia. Concordia is one of three large residential and commercial developments in the area surrounding the existing Gawler distribution network, the others being Springwood and Roseworthy. The Springwood Estate commenced construction during the last AA period, with stages 1 to 4 complete and stages 5 to 8 to follow. The Roseworthy Estate remains under construction, with critical water and sewer infrastructure installed and housing development to continue throughout 2025 and beyond. Gas is being supplied to both these estates.

Concordia is an area of rural land adjoining the eastern boundary of Gawler, located about 42 km north of Adelaide (see Figure 0.1). It is a 'future urban growth area', forming part of the SA Government's 30-year growth strategy[21]. Concordia is a gateway to the Barossa Valley and is close to the Northern Express Way, Northern Connector and the Gawler East Link Road.

Figure 0.1: Map of the Concordia development area



The developer plans to transform the 935-hectare site into a master-planned community that will form a natural extension of the existing Gawler Township. The Concordia development

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[21] Available at: https://livingadelaide.sa.gov.au/

will contribute to the physical and social infrastructure of Gawler and Barossa districts, whilst providing a critical mass to support and underpin the economic strength and viability of local businesses, services and institutions.

Greenfield growth in Concordia was originally forecast to commence during the current period (2021-26). However, due to the co-location of energy, water and wastewater services, and the delay in particular with approvals for water and sewer works this has not yet occurred.

Despite the delay, no changes have been made to the structure plans, which means there is no requirement for re-approval or reconsideration of the master plan. This, combined with communication from the developer of the new timeline, means this project is likely to proceed to the revised forecast dates.

[redacted] the project developer, has confirmed that the development is still intended to be supplied by the gas network and the new date by which the Concordia area will need to be fully reticulated is 2029 (see Appendix C).

1.3.1 Expected demand for natural gas

By 2050, Concordia is expected to include approximately 7,000 homes, plus schools, community facilities and shopping centres to support a population of 17,500 residents. Concordia Land Management (CLM, the planners responsible for the allocation of lots) has signalled its intent to include provision of natural gas to the development, stating that it *sees natural gas as an important part of the provision of sustainable and affordable fuels options for the Concordia development.*[22]

Table 0.3 provides the forecast residential allotments, dwellings and population for the development. Around 40 commercial connections are also expected.

Table 0.3: Concordia residential allotments, dwellings and population forecast

Year	Lots sold	Allotments created (cumulative)	Dwellings commenced	Dwellings occupied cumulative	Population (cumulative at 2.5 people per household)
2028	0	0	0	0	0
2032	225	655	180	430	1,075
2037	375	2,255	350	1,880	4,700
2042	380	4,150	380	3,770	9,425
2047	350	5,975	360	5,625	14,063
2051	150	7,000	150	7,000	17,500

Source: Concordia Land Management, November 2024

1.3.1.0 Gas penetration rates and estimated growth

Historically, more than 7,000 new residential dwellings are connected to the natural gas distribution network in greater Adelaide each year. The average gas penetration rate for greenfield residential developments is greater than 80%. Historical penetration rates are shown in Figure 0.2.

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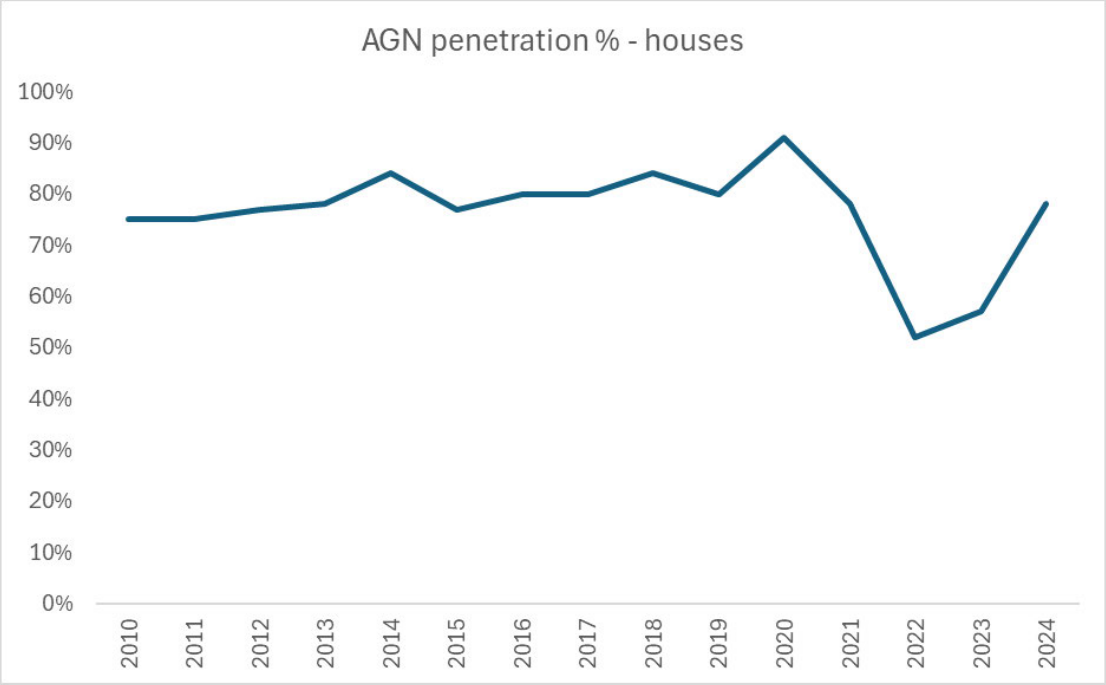
[22] Ibid.

Figure 0.2: Penetration rates for SA network houses over time



The penetration rate has remained strong (>80%) for most of the past two decades. The anomaly in 2021-2022 was due to the impacts of the COVID-19 pandemic on the housing construction industry. This can be seen recovering post-2022, with the expectation it will return to historical pre-COVID trend during 2025. Though the penetration rate was trending as high a 90% prior to the pandemic, for the purposes of hydraulic modelling, we have used a more conservative 80% penetration rate assumption as a reasonable forward-looking forecast. This is consistent with the rate used in the Network Augmentation Plan.

The use of an 80% penetration rate and 13.5 GJ per annum average consumption is supported by our experience with new developments in South Australia as shown in Table 0.4.

Table 0.4: Penetration rates for recent developments in South Australia

Suburb	Gas	No Gas	Total	% Penetration	Ave Cons 2024 (GJ/Annum)
Angle Vale	2,522	412	2,934	86%	15.0
Munno Para	1,327	146	1,473	90%	12.6
Riverlea Park	443	68	511	87%	11.1
Virginia	630	305	935	67%	12.5
Total	**4,922**	**931**	**5,853**	**84%**	**13.7**

Based on the information provided by the developer, 430 allotments in the Concordia development will have been created by the end of the period. If we apply an 80% penetration rate, this means 344 residential dwellings will need to be supplied with gas during the next five years, with 6,440 dwellings needing supply over the long term (to 2058).

Based on the forecast growth in residential developments alone, high level economic analysis indicates connecting the Concordia estate with natural gas[23] will deliver positive returns within a reasonable period of time (20 years – see section 1.5 and Attachment D for a summary of the net present value (NPV) analysis). The incremental revenue from commercial customers has not been included in our NPV analysis at this time, however the connection of industrial and commercial (I&C) or Tariff D customers would only strengthen the business case from an economic perspective.

1.4 Options considered

We have considered the following options:

- **Option 1** – Connect Concordia to the Gawler high pressure network near the Gawler Gate Station
- **Option 2** – Connect Concordia to the Gawler high pressure network north of the development near Roseworthy
- **Option 3** – Do not offer a gas supply to the area

These options are discussed in the following sections.

1.4.1 Option 1 – Connect Concordia to the Gawler high pressure network near Gawler Gate Station

Under this option, we would connect Concordia to the existing Gawler natural gas distribution network at Calton Road, downstream of the new Gawler Gate Station.

We would install 2.7 km of DN280 polyethylene mains, running 1 km from Calton Road to the development, and extending a further 1.7 km into Concordia.

The proposed route for this option is shown in Appendix A.

1.4.1.0 Advantages and disadvantages

The proposed route is relatively risk free and gives us a good level of confidence with our forecast and the timing of the construction project will enable customers to connect quickly to the network upon construction of their homes and businesses, with the infrastructure in place and ready for use.

Connecting the Concordia estate to the Gawler high pressure network in close proximity to the newly constructed Gawler Gate Station reduces any flow restrictions through smaller mains and reduces the risk of compounding future pressure drop issues in the Gawler and Willaston areas.

The possible disadvantage to this project is that if the construction of houses and businesses does not materialise at the forecast rate, or the penetration rate is significantly below ~80% we would be incurring costs ahead of when we otherwise could. Notwithstanding this, due to the need to diversify clean energy options, it is likely the gas infrastructure would still be required at some point, both to meet eventual growth and to offer diversity of energy supply.

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[23] Note that while this business case does not include the costs associated with reticulating the estate, these costs have been included in the NPV assessment.

The risk associated with the infrastructure not being available at the time of connection is that brownfields supply costs two to three times more than greenfields supply.

1.4.1.1 Cost assessment

The direct cost of this option is $4.3 million (see Table 0.5).

Table 0.5: Cost estimate – Option 1, $’000 January 2025

	2026/27	2027/28	2028/29	2029/30	2030/31	Total
Labour Costs	-	[redacted]	-	-	-	[redacted]
Material Costs	-	[redacted]	-	-	-	[redacted]
Total	**-**	**4,340**	**-**	**-**	**-**	**4,340**

Note some totals may not sum due to rounding

Appendix B provides a more detailed cost breakdown.

1.4.1.2 Alignment with vision objectives

Table 0.6 shows how Option 1 aligns with our vision objectives.

Table 0.6: Alignment with AGN vision – Option 1

Vision objective	Alignment
Customer Focussed – Public Safety	-
Customer Focussed – Customer Experience	Y
Customer Focussed – Cost Efficient	Y
A Leading Employer – Health and Safety	-
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	Y
Operational Excellence – Benchmark Performance	-
Operational Excellence – Reliability	-
Sustainable Communities – Enabling Net Zero	Y
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	-

Option 1 aligns with our objective of *Customer Focussed*, as it will ensure customers who want to use natural gas in Concordia, can connect. Installing the distribution assets as part of a greenfield development is also the most efficient method of providing natural gas supply.

Option 1 also aligns with our objective of *Operational Excellence*, as expanding the network into the Concordia growth area will increase the number of network connections, spreading the total network costs over a larger customers base.

This option aligns with *Sustainable Communities* as infrastructure is renewable gas ready, enabling net zero.

1.4.2 Option 2 – Connect Concordia to the Gawler high pressure network near Roseworthy

Under this option, we would connect Concordia to the existing Gawler high pressure network near Roseworthy, at the northern end of the development. This is the second closest trunk main to the development.

This option would require the installation of approximately 3 km of DN280 polyethylene main through private land along the northern edge of the Concordia development and into the Concordia land area. It would also require boring across a river.

1.4.2.0 Advantages and disadvantages

The major disadvantage of this option is the proposed route. While the overall length of mains required to supply Concordia from the north is similar to Option 1, the route includes a river crossing and traverses private land that would require an easement. Both of these introduce a larger level of uncertainty into the forecast cost as well increased likelihood of planning delays. This could also result in delays to project construction, which could result in a mismatch of timing between headworks and reticulation, risking a lower proportion of greenfields connections and/or a lower penetration rate for the development overall.

Connecting to the Gawler network further from the Gawler Gate Station will also introduce flow restrictions due to intermediary mains of smaller diameters which may compound the forecast future pressure drops in the Gawler, Willaston and Roseworthy areas.

Similarly to Option 1, if the construction of houses and businesses does not materialise at the forecast rate, or the penetration rate is significantly below ~80% we would be incurring costs ahead of when we otherwise could. Not withstanding this, due to the need to diversify clean energy options, it is likely the gas infrastructure would still be required at some point, both to meet eventual growth and to offer diversity of energy supply. The risk associated with the infrastructure not being available at the time of connection is that brownfields supply costs two to three times more than greenfields supply.

1.4.2.1 Cost assessment

The direct cost of this option is $8.2 million (see Table 0.7).

Table 0.7: Cost estimate – Option 2, $’000 January 2025

	2026/27	2027/28	2028/29	2029/30	2030/31	Total
Labour Costs	25	[redacted]	-	-	-	[redacted]
Material Costs	-	[redacted]	-	-	-	[redacted]
Total	**25**	**8,147**	**-**	**-**	**-**	**8,172**

Note some totals may not sum due to rounding

1.4.2.2 Alignment with vision objectives

Table 0.8 shows how Option 2 aligns with our vision objectives.

Table 0.8: Alignment with vision – Option 2

Vision objective	Alignment
Customer Focussed – Public Safety	-
Customer Focussed – Customer Experience	Y

Vision objective	Alignment
Customer Focussed – Cost Efficient	N
A Leading Employer – Health and Safety	-
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	N
Operational Excellence – Benchmark Performance	-
Operational Excellence – Reliability	N
Sustainable Communities – Enabling Net Zero	Y
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	-

Option 2 aligns with our objective of *Customer Focussed*, as it will ensure customers who want to use natural gas in Concordia, can connect. Installing the distribution assets as part of a greenfield development is also the most efficient method of providing natural gas supply.

Option 2 aligns in part with our objective of *Operational Excellence*, as expanding and reticulating into the Concordia growth area will increase the number of network connections, spreading the total network costs over a larger customers base.

However, this option is not the preferred solution because the forecast costs are significantly higher with an increased likelihood of escalation due to a challenging route. Option 2 does not address the forecast pressure drop issues in the existing Gawler network as effectively as Option 1, meaning customers in the surrounding areas will not benefit from improved pressures as they would in Option 1.

This option also aligns with *Sustainable Communities* as infrastructure is renewable gas ready, enabling net zero.

1.4.3 Option 3 – Do not offer a gas supply to the area

Under this option we would not proactively supply the Concordia estate with natural gas. We would instead adopt a user-pays model in which the supply and reticulation is driven by individual customer contributions, with gas infrastructure installed post-development as brownfields connections.

1.4.3.0 Advantages and disadvantages

The advantage of this option is that there would be no upfront capital cost. However, the long-term costs would increase (compared with Option 1) for those customers remaining on the network as the same fixed costs are shared over fewer customers.

If the Concordia expansion and reticulation project is deferred to after initial development works, the opportunity to deliver the works efficiently as part of the greenfield development will be foregone. Typically, the cost of laying mains and services in a brownfield development is around two to three times more expensive than installing these assets in a greenfield project.

Historically, penetration rates for brownfield developments are also lower than for new builds. When reticulating brownfield areas, gas connection requests and penetration rates are primarily driven by appliance changeover decisions. As a result, typical gas penetration rates in brownfields areas can grow as slowly as 2% to 5% per year.

If the Concordia development is deferred and reticulated as a brownfield project, not only would the costs be higher, the likely gas uptake and therefore the benefits to all consumers would be lower.

Table 0.9: Comparison of greenfield v brownfield development costs

Current average cost	Greenfields developments	Brownfields developments
Main (cost per metre)	[redacted]	[redacted]
Services (cost per unit)	[redacted]	[redacted]
Meter (cost per unit)	[redacted]	[redacted]

Under this option we would forego the opportunity for incremental revenue from around 8,000 new residential connections, 40 I&C customers, and potentially some Tariff D customers between now and 2058. More significantly, there is sufficient evidence from the developer and prospective customers in the Concordia region that a natural gas connection is desired. The developer has stated its intent to make a natural gas supply available to the new residents and businesses in Concordia, and historical penetration rates for new developments tell us that customers continue to want and value a gas connection. We would therefore be exposed to some reputational risk if we choose not to uphold our commitment to providing a reliable and affordable natural gas supply to South Australians.

A further disadvantage to this option is that customers in the region will not have the security of a diverse energy supply. While all-electric properties are an attractive proposition for some customers, it means the house or business is entirely dependent on the reliability of the electricity grid, and the production of green electrons. Not only does a gas network connection offer a reliable alternative (and complementary) energy supply, it also allows the customer to benefit from evolving gas technologies such as biomethane and lower carbon gas blends, which would ultimately be supplied via the AGN SA network.

1.4.3.1 Cost assessment

There are no upfront capital costs associated with this option.

1.4.3.2 Alignment with vision objectives

Table 0.10 shows how Option 3 aligns with our vision objectives.

Table 0.10: Alignment with vision – Option 3

Vision objective	Alignment
Customer Focussed – Public Safety	-
Customer Focussed – Customer Experience	N
Customer Focussed – Cost Efficient	-
A Leading Employer – Health and Safety	-
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	N
Operational Excellence – Benchmark Performance	-
Operational Excellence – Reliability	-
Sustainable Communities – Enabling Net Zero	N
Sustainable Communities – Environmentally Focussed	-

Vision objective	Alignment
Sustainable Communities – Socially Responsible	-

Option 3 would not align with our objective to be *Customer Focussed*, as Concordia residents that want a natural gas connection will not be able to connect to the network.

Option 3 would also not reflect *Operational Excellence*, as the supply of natural gas to Concordia returns a positive NPV and therefore it delivers profitable growth in the network, which new and existing customers would benefit from.

This option would not align with *Sustainable Communities* as no infrastructure would be available to deliver renewable gas that will assist in enabling net zero.

1.5 Summary of costs and benefits

Table 0.19 presents a summary of how each option compares in terms of the estimated cost, alignment with our objectives and NPV.

To assess which solution is likely to cost the most over time, we have conducted a net present cost assessment of Options 1 and 2. Further details of the NPV assessment can be found in Appendix D.

Table 0.11: Comparison of options

Option	Estimated cost	Alignment with AGN vision objectives	NPV
Option 1 – Supply from near Gawler Gate Station	$4.3 million	Aligns with our objectives of *Customer Focussed, Operational Excellence* and *Sustainable Communities*	$1.1 million at 20 years* $12.5 million at 30 years
Option 2 – Supply from near Roseworthy	$8.2 million	Aligns with our objectives of *Customer Focussed* and *Sustainable Communities,* partially aligns with *Operational Excellence*	-$2.9 million at 20 years $1.0 million at 23 years* $8.5 million at 30 years
Option 3 – Do not supply	No upfront capital costs	Does not align with our objectives of *Customer Focussed, Operational Excellence* or *Sustainable Communities*	N/A

*First positive NPV year

1.6 Proposed solution

Option 1, connecting to the Gawler high pressure network, near the new Gawler Gate Station, is the recommended option.

1.6.1 Why is the recommended option prudent?

Option 1 is the most efficient and practicable technical solution, particularly given the completion of the new Gawler Gate Station.

Option 1 returns an NPV of $1.1 million after 20 years. As a result, it passes the incremental revenue test specified under NGR 79(2)(b).

Connecting to the existing Gawler high pressure network and reticulating the site as a greenfields project will enable new homes and businesses to connect immediately and at a lower overall cost than if the Concordia development was to be connected at a different point, or were to be constructed as a brownfields project. Developers and potential customers have expressed a desire for natural gas in the area, and there is sufficient evidence that the forecast number of new connections will arise if the necessary gas infrastructure in installed.

Option 3 (not supplying the Concordia growth area) is not recommended, as the opportunity for new connections and incremental revenue will be foregone.

1.6.2 Estimating efficient costs

The unit rates used for all projects managed within this program of work include the internal labour, external labour and materials/other costs forecast.

Key assumptions that have been made in the cost estimation include:

- The cost estimate is based on costing the activities that comprise the work breakdown structure
- The rates utilised in costing these activities are based on current vendor and contractor rates in January 2025 and historical costings
- The distribution assets will be installed as part of a greenfields development

This project will be delivered using a combination of internal and external resources. The project will be initiated internally by the asset manager. Design, project management and installation will be completed by contractors. Contractors will be selected through a competitive tender process. Quality assurance and project closure will be handled by internal resources.

Current project delivery practices and controls such as advanced planning and scheduling of work are in place to effectively manage risk in delivery. The risk of not completing this project is considered to be low. Delivery of this project will need to be complete in the first year of the period, with the reticulation (not included in this business case) phased over the remainder of the period.

The project timeframe with respect to provision of infrastructure and connection of customers is based on discussions with the developer.

1.6.3 Consistency with the National Gas Rules

NGR 79(1)

The proposal to supply the new Concordia development from the Gawler high pressure network near the new Gawler Gate Station is consistent with the requirements of NGR 79(1). Specifically, we consider that the capital expenditure is:

- **Prudent** – The expenditure is necessary to supply natural gas to new customers. The land developer has expressed a desire to offer natural gas to residents, and historical penetration rates indicate that substantial demand for natural gas will occur. The proposed design is consistent with accepted industry practice and current standards and will enable new customers to connect immediately. A range of practicable options have been considered, and the most prudent option to support the ongoing growth and integrity of the network has been considered. The proposed expenditure is therefore consistent with that which would be incurred by a prudent service provider.
- **Efficient** – Supplying the Concordia development with natural gas such that it can be reticulated as part of a greenfields development is the most efficient solution and is two to three times less expensive than undertaking the works as part of a brownfields development. The forecast costs have been developed using current vendor rates and historical precedent. The preferred option returns a positive NPV after 20 years.

- **Consistent with accepted industry practice** – The recommended technical solution is consistent with current standards, and will provide an overall reliability benefits to surrounding areas when compared to alternative options. Moreover, continuing to connect customers to the existing network, allowing overall costs to be shared amongst a greater number of customers will keep the cost of supply down over the long term.

- To achieve **the lowest sustainable cost of delivering pipeline services** – The proposed option has the lowest direct costs and returns a positive NPV after 20 years. Increasing the number of customers connected to the network helps spread total network costs over a larger customer-base and helps us deliver pipeline services at a lower cost per customer. The proposed route has the least likelihood of cost escalation.

NGR 79(2)

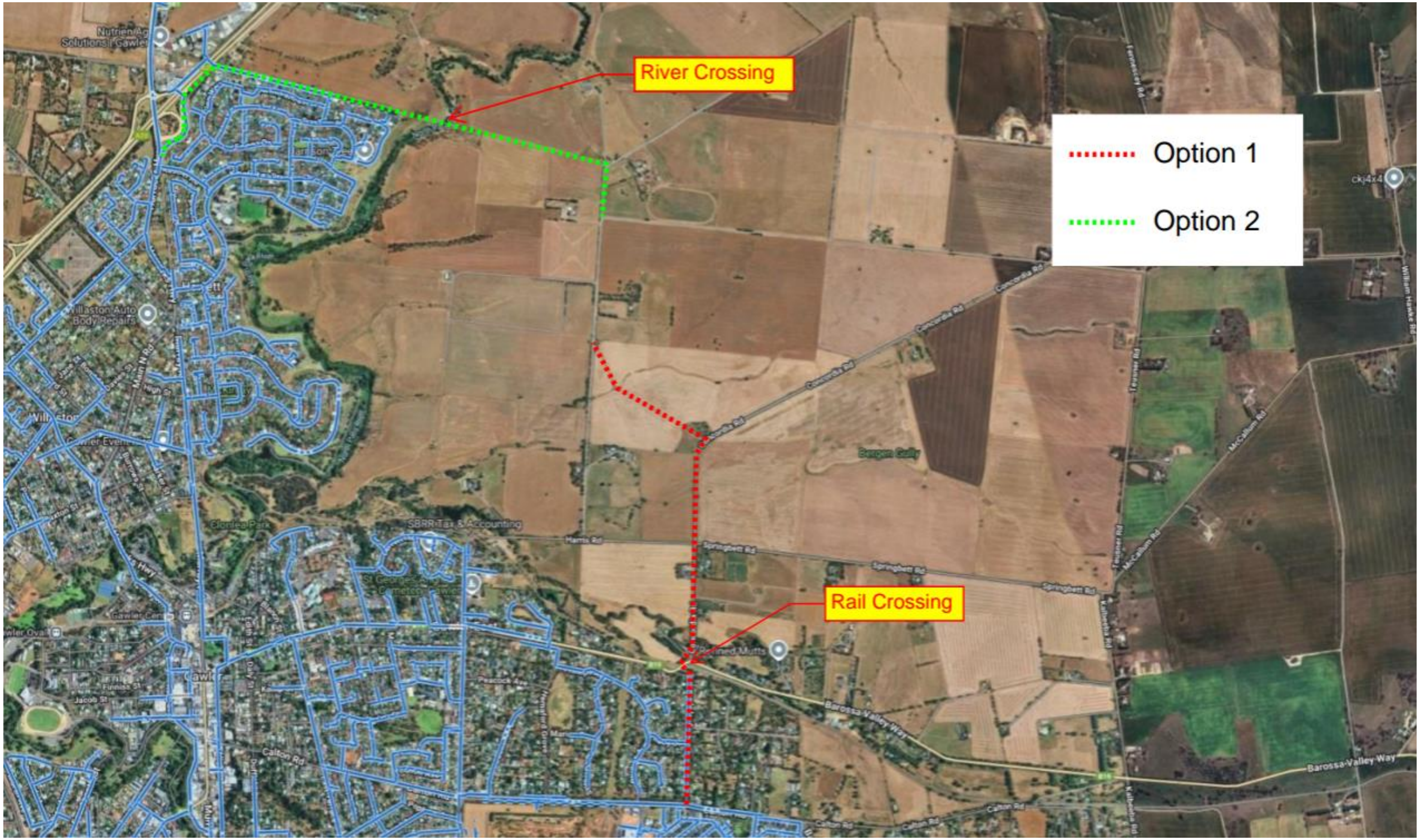
The proposed capex is justifiable under 79(2)(b) as the present value of the expected incremental revenue to generated as a result of the supply of Concordia exceeds the present value of the capital expenditure, returning a positive NPV after 20 years.

NGR 74

The forecast costs are based on the latest market rate testing and estimated demand in the region is based on evidence provided by developers and prospective customers. We have also used precedents set in similar network expansions to inform the forecast number of connections and penetrations rates. An NPV assessment has been conducted for the recommended option. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.

Appendix A Asset location map

Figure A.1: Route of two proposed pipeline solutions



Appendix B Cost estimate for proposed solution

Labour - Trunk

Category	Description	No. Items / Metres	Unit Rate ($/unit)	Total Unit Cost
Labour - Contractor	Contractor pipelaying	[redacted]	[redacted]	[redacted]
Labour - Contractor	Tie ins and poly stops	[redacted]	[redacted]	[redacted]
Labour - Contractor	Hydrotesting	[redacted]	[redacted]	[redacted]
Labour - Contractor	HDD	[redacted]	[redacted]	[redacted]
Labour - Contractor	Traffic management	[redacted]	[redacted]	[redacted]
Labour - Contractor	Survey and geotech	[redacted]	[redacted]	[redacted]
Labour	APA Supervisor	[redacted]	[redacted]	[redacted]
Labour	Project Engineer	[redacted]	[redacted]	[redacted]
Labour	Project Manager	[redacted]	[redacted]	[redacted]
Labour - Contractor	Rock - HDD and mainlaying	[redacted]	[redacted]	[redacted]
Labour - Consultant	Rail license / approval	[redacted]	[redacted]	[redacted]
Labour	Commissioning	[redacted]	[redacted]	[redacted]
			[redacted]	[redacted]

Materials - Trunk

Category	Description	No. Items / Metres	Unit Rate	Total Unit Cost
Materials - pipe	DN280 pipe and DN355 casings	[redacted]	[redacted]	[redacted]
Materials - valves	Valves and chambers	[redacted]	[redacted]	[redacted]
Materials - fittings	Miscellaneous fittings	[redacted]	[redacted]	[redacted]
Material	Freight and storage	[redacted]	[redacted]	[redacted]
			[redacted]	[redacted]
			Total Project Costs - Trunk	[redacted]

The reticulation cost of this option is $1.03 million over the next five years, is provided in Table .

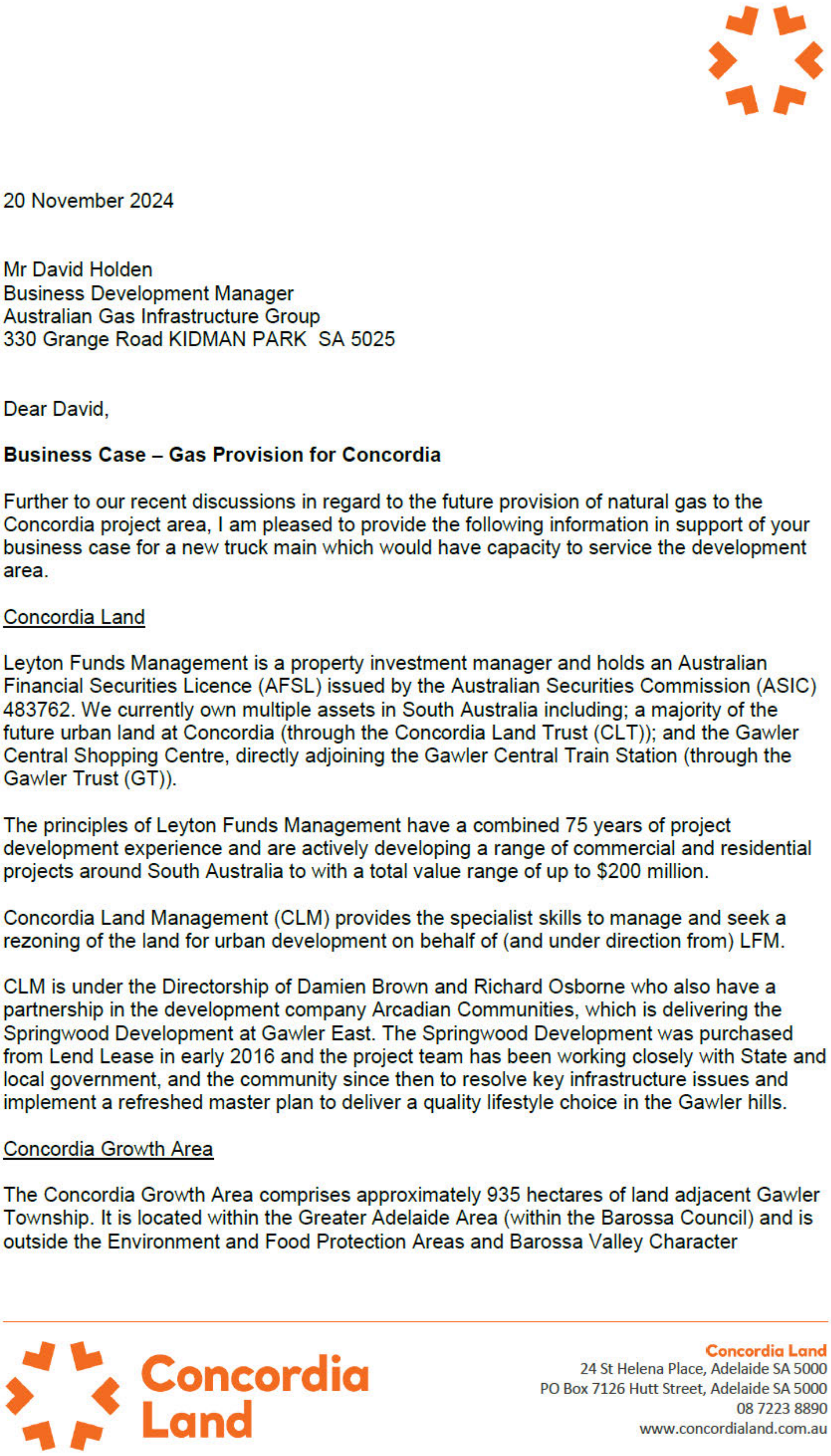
Note that approval of these costs is not sought as part of this business case. Reticulation costs are forecast at a macro level and are included as part of AGN's growth capex forecast. This is included in the provided capex model and reflects:

- The number of connections estimated in our demand forecast
- The average unit rate provided Attachment 9.10: Unit Rates Report

Table A.2: Cost estimate – Reticulation costs associated with the proposed solution (Option 1), $'000 January 2025

	2026/27	2027/28	2028/29	2029/30	2030/31	Total
Reticulation mains	-	-	[redacted]	[redacted]	[redacted]	[redacted]
Inlets	-	-	[redacted]	[redacted]	[redacted]	[redacted]
Meters	-	-	[redacted]	[redacted]	[redacted]	[redacted]
Total	**-**	**-**	[redacted]	[redacted]	[redacted]	[redacted]

Appendix C Letter from Concordia Land Management



20 November 2024

Mr David Holden
Business Development Manager
Australian Gas Infrastructure Group
330 Grange Road KIDMAN PARK SA 5025

Dear David,

Business Case – Gas Provision for Concordia

Further to our recent discussions in regard to the future provision of natural gas to the Concordia project area, I am pleased to provide the following information in support of your business case for a new truck main which would have capacity to service the development area.

Concordia Land

Leyton Funds Management is a property investment manager and holds an Australian Financial Securities Licence (AFSL) issued by the Australian Securities Commission (ASIC) 483762. We currently own multiple assets in South Australia including; a majority of the future urban land at Concordia (through the Concordia Land Trust (CLT)); and the Gawler Central Shopping Centre, directly adjoining the Gawler Central Train Station (through the Gawler Trust (GT)).

The principles of Leyton Funds Management have a combined 75 years of project development experience and are actively developing a range of commercial and residential projects around South Australia to with a total value range of up to $200 million.

Concordia Land Management (CLM) provides the specialist skills to manage and seek a rezoning of the land for urban development on behalf of (and under direction from) LFM.

CLM is under the Directorship of Damien Brown and Richard Osborne who also have a partnership in the development company Arcadian Communities, which is delivering the Springwood Development at Gawler East. The Springwood Development was purchased from Lend Lease in early 2016 and the project team has been working closely with State and local government, and the community since then to resolve key infrastructure issues and implement a refreshed master plan to deliver a quality lifestyle choice in the Gawler hills.

Concordia Growth Area

The Concordia Growth Area comprises approximately 935 hectares of land adjacent Gawler Township. It is located within the Greater Adelaide Area (within the Barossa Council) and is outside the Environment and Food Protection Areas and Barossa Valley Character

Concordia Land
24 St Helena Place, Adelaide SA 5000
PO Box 7126 Hutt Street, Adelaide SA 5000
08 7223 8890
www.concordialand.com.au

Preservation District boundaries. This land is required to accommodate urban growth in the northern region of Adelaide over the coming years.

In April 2023, the State Government commenced a rezoning process for the whole of the Concordia Growth Area which his due to be completed by the end of 2025. This process is being managed by the Department of Housing and Urban Development.

Concordia Master Planned Development

CLM has a vision to develop Concordia into South Australia's pre-eminent master planned community which maximises the State's significant infrastructure investment already made in the region. Concordia will be a sustainable, resilient, innovative and inclusive community with an urban form that reflects the character of its unique location.

Concordia will be home to a community of approximately 10,000-12,000 homes and 24 – 28,000 residents. The development comprises the following key features:

- A mixed use Village Centre located within close proximity and immediately north of the future rail station/ transport hub enabling walking permeability and easy connection;
- Two local community hubs including school, retail, community uses and public spaces located to maximise the residential catchments and creating important amenity and services for residents;
- Provision of a comprehensive range of community, education, health, recreation, commercial and retail facilities to support the new community;
- Extension of the electrified rail service to Concordia incorporating a new rail station and depot (subject to Federal Government support);
- Creation of a sub-arterial road network providing efficient and fluid movement through the Growth Area, including development of the North East Link Road providing a strategic regional road connection between the Barossa Valley Way and the Sturt Highway;
- Alignment of roadways to maximise the natural topography and features of the terrain;
- A comprehensive green network to create a defining feature for Concordia as a connected, functional and verdant place, including improvements to the biodiversity value of areas adjacent to the North Para River and Whitelaw Creek;
- Provision of integrated utilities solutions (water, sewer, energy) harnessing best practice alternative technologies, which will reduce development costs, operational costs for households and environment impacts;
- Using the green network to play a critical role in stormwater drainage and water quality treatment;
- A variety of housing densities and types including medium density residential development located to support and activate the Village Centre;
- Provision of an appropriate buffer to the adjoining rural land incorporating 'edge planning' techniques; and
- A future freight route to the periphery of the site, to assist in creating and managing the rural/ urban interface.

Development approval timing

While the rezoning of Concordia is due for completion by the end of 2025, timing of the commencement of development is largely contingent on the provision of essential services including water, sewer and electricity. As you would be aware the State Government has recently acknowledged a severe underinvestment in water and sewer services in South Australia over the past 20 years which has resulted in the development of a Roadmap for Housing to guide investment in these services moving forward to address the current housing crisis. The program for the provision of services to Concordia is still being developed. While the Roadmap document states that Concordia will not be fully serviced until 2029, we are currently working with Government to secure access to water and sewer services at an earlier date.

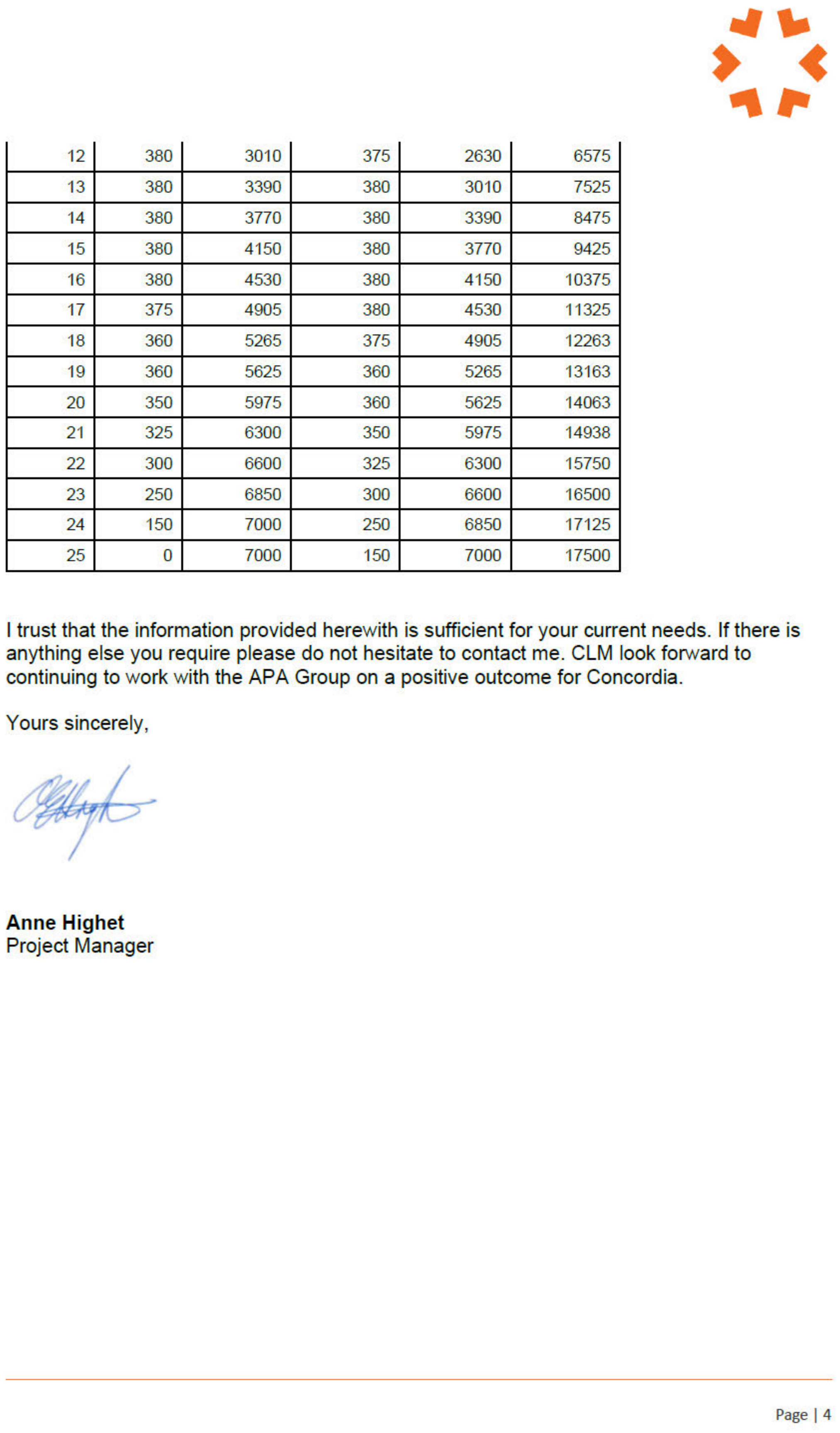
Planning to include natural gas

Our intention at this time is to include the provision of natural gas to the development, subject to a resolution of the augmentation required. CLM see natural gas and potential hydrogen mix fuels as part of the provision of sustainable and affordable fuel options for the Concordia development, albeit that energy sources, preferences and costs are a rapidly changing field.

Lot yield and take up rates

This table sets out predicted lot take up rates for CLM's land only. The remainder of the Concordia Growth Area will yield another 5000 lots over and possible 35 year development timeframe.

Year	Lots Sold	Lots Cumulative	Dwellings Commence	Dwellings Occupied Cumulative	Pop Cumulative 2.5 per household
1	0	0	0	0	0
2	100	0	0	0	0
3	150	250	100	100	250
4	180	430	150	250	625
5	225	655	180	430	1075
6	250	905	225	655	1638
7	300	1205	250	905	2263
8	325	1530	300	1205	3013
9	350	1880	325	1530	3825
10	375	2255	350	1880	4700
11	375	2630	375	2255	5638



12	380	3010	375	2630	6575
13	380	3390	380	3010	7525
14	380	3770	380	3390	8475
15	380	4150	380	3770	9425
16	380	4530	380	4150	10375
17	375	4905	380	4530	11325
18	360	5265	375	4905	12263
19	360	5625	360	5265	13163
20	350	5975	360	5625	14063
21	325	6300	350	5975	14938
22	300	6600	325	6300	15750
23	250	6850	300	6600	16500
24	150	7000	250	6850	17125
25	0	7000	150	7000	17500

I trust that the information provided herewith is sufficient for your current needs. If there is anything else you require please do not hesitate to contact me. CLM look forward to continuing to work with the APA Group on a positive outcome for Concordia.

Yours sincerely,

Anne Highet
Project Manager

Appendix D NPV summary

General assumptions

Nominal discount rate	6.84%
Tariff	Domestic excl Tanunda
Incremental ongoing opex	$28.37 per connection
Evaluation period	30 years
Overhead	5.0%
CPI	2.66%
X-Factor	0.72%

Revenue assumptions

Number of lots	8,050
Penetration	78%
Number of meters	6,279
Build Out	20 years
ACQ per connection	13.5 GJ
Revenue	$621.96 pa

Capital assumptions (direct cost)

Supply main	[redacted]
Augmentation	[redacted]
Reticulation	[redacted]
Service	[redacted]
Meter reg/assembly	[redacted]

NPV: Option 1

Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Customer Numbers (Res only)	0	80.0	200	344	524	724	964	1224	1504	1804	2104	2408	2712	3016	3320	3624
Customer Numbers (Comm)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Revenue	$0	$40,468	$137,483	$242,761	$379,623	$538,470	$736,040	$959,416	$1,210,248	$1,490,268	$1,784,329	$2,096,461	$2,423,937	$2,767,351	$3,127,320	$3,504,480
Upfront Contribution	$0															
Operating Expenditure	$0	$2,330	$5,980	$10,559	$16,512	$23,421	$32,014	$41,730	$52,640	$64,820	$77,610	$91,186	$105,430	$120,367	$136,024	$152,429
Operating Cashflow	$0	$38,138	$131,503	$232,202	$363,111	$515,049	$704,025	$917,685	$1,157,608	$1,425,448	$1,706,719	$2,005,275	$2,318,507	$2,646,984	$2,991,296	$3,352,052
Capital Expenditure	$4,621,925	$312,578	$450,697	$561,514	$698,137	$812,713	$974,727	$1,082,425	$1,195,162	$1,292,675	$1,331,260	$1,380,524	$1,417,246	$1,454,945	$1,493,647	$1,528,588
Cashflow	-$4,621,925	-$274,441	-$319,194	-$329,312	-$335,026	-$297,664	-$270,701	-$164,739	-$37,554	$132,774	$375,459	$624,751	$901,261	$1,192,039	$1,497,649	$1,823,464
Cumulative NPV @ 6.84%	-$4,621,925	-$4,878,796	-$5,158,428	-$5,428,454	-$5,685,578	-$5,899,403	-$6,081,409	-$6,185,081	-$6,207,201	-$6,134,002	-$5,940,260	-$5,638,519	-$5,231,097	-$4,726,727	-$4,133,616	-$3,457,706
Cummulative IRR											**#NUM!**	**-18.26%**	**-11.49%**	**-6.64%**	**-2.98%**	**-0.13%**

Year	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
Customer Numbers (Res only)	3924	4212	4500	4780	5040	5040	5040	5040	5040	5040	5040	5040	5040	5040	5040
Customer Numbers (Comm)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Revenue	$3,895,522	$4,292,658	$4,708,166	$5,134,148	$5,557,408	$5,705,235	$5,856,994	$6,012,790	$6,172,730	$6,336,925	$6,505,487	$6,678,533	$6,856,182	$7,038,557	$7,225,782
Upfront Contribution															
Operating Expenditure	$169,437	$186,711	$204,783	$223,312	$241,721	$248,151	$254,752	$261,528	$268,485	$275,627	$282,958	$290,485	$298,212	$306,144	$314,288
Operating Cashflow	$3,726,085	$4,105,948	$4,503,382	$4,910,836	$5,315,686	$5,457,084	$5,602,242	$5,751,262	$5,904,245	$6,061,298	$6,222,529	$6,388,048	$6,557,970	$6,732,412	$6,911,494
Capital Expenditure	$1,538,702	$1,530,984	$1,561,344	$1,542,096	$1,140,409	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cashflow	$2,187,383	$2,574,964	$2,942,038	$3,368,740	$4,175,278	$5,457,084	$5,602,242	$5,751,262	$5,904,245	$6,061,298	$6,222,529	$6,388,048	$6,557,970	$6,732,412	$6,911,494
Cumulative NPV @ 6.84%	-$2,698,809	-$1,862,638	-$968,430	-$10,081	$1,101,671	$2,461,703	$3,768,525	$5,024,220	$6,230,786	$7,390,147	$8,504,149	$9,574,568	$10,603,107	$11,591,405	$12,541,038
Cummulative IRR	**2.16%**	**4.03%**	**5.56%**	**6.83%**	**7.99%**	**9.10%**	**9.94%**	**10.60%**	**11.13%**	**11.57%**	**11.93%**	**12.23%**	**12.48%**	**12.70%**	**12.88%**

NPV: Option 2

Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Customer Numbers (Res only)	0	80.0	200	344	524	724	964	1224	1504	1804	2104	2408	2712	3016	3320	3624
Customer Numbers (Comm)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Revenue	$0	$40,468	$137,483	$242,761	$379,623	$538,470	$736,040	$959,416	$1,210,248	$1,490,268	$1,784,329	$2,096,461	$2,423,937	$2,767,351	$3,127,320	$3,504,480
Upfront Contribution	$0															
Operating Expenditure	$0	$2,330	$5,980	$10,559	$16,512	$23,421	$32,014	$41,730	$52,640	$64,820	$77,610	$91,186	$105,430	$120,367	$136,024	$152,429
Operating Cashflow	$0	$38,138	$131,503	$232,202	$363,111	$515,049	$704,025	$917,685	$1,157,608	$1,425,448	$1,706,719	$2,005,275	$2,318,507	$2,646,984	$2,991,296	$3,352,052
Capital Expenditure	$8,645,436	$312,578	$450,697	$561,514	$698,137	$812,713	$974,727	$1,082,425	$1,195,162	$1,292,675	$1,331,260	$1,380,524	$1,417,246	$1,454,945	$1,493,647	$1,528,588
Cashflow	-$8,645,436	-$274,441	-$319,194	-$329,312	-$335,026	-$297,664	-$270,701	-$164,739	-$37,554	$132,774	$375,459	$624,751	$901,261	$1,192,039	$1,497,649	$1,823,464
Cumulative NPV @ 6.84%	-$8,645,436	-$8,902,306	-$9,181,938	-$9,451,965	-$9,709,089	-$9,922,913	-$10,104,920	-$10,208,592	-$10,230,712	-$10,157,512	-$9,963,771	-$9,662,030	-$9,254,608	-$8,750,237	-$8,157,127	-$7,481,216
Cummulative IRR											**#NUM!**	**-21.52%**	**-15.05%**	**-10.33%**	**-6.71%**	**-3.85%**

Year	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
Customer Numbers (Res only)	3924	4212	4500	4780	5040	5040	5040	5040	5040	5040	5040	5040	5040	5040	5040
Customer Numbers (Comm)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Revenue	$3,895,522	$4,292,658	$4,708,166	$5,134,148	$5,557,408	$5,705,235	$5,856,994	$6,012,790	$6,172,730	$6,336,925	$6,505,487	$6,678,533	$6,856,182	$7,038,557	$7,225,782
Upfront Contribution															
Operating Expenditure	$169,437	$186,711	$204,783	$223,312	$241,721	$248,151	$254,752	$261,528	$268,485	$275,627	$282,958	$290,485	$298,212	$306,144	$314,288
Operating Cashflow	$3,726,085	$4,105,948	$4,503,382	$4,910,836	$5,315,686	$5,457,084	$5,602,242	$5,751,262	$5,904,245	$6,061,298	$6,222,529	$6,388,048	$6,557,970	$6,732,412	$6,911,494
Capital Expenditure	$1,538,702	$1,530,984	$1,561,344	$1,542,096	$1,140,409	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cashflow	$2,187,383	$2,574,964	$2,942,038	$3,368,740	$4,175,278	$5,457,084	$5,602,242	$5,751,262	$5,904,245	$6,061,298	$6,222,529	$6,388,048	$6,557,970	$6,732,412	$6,911,494
Cumulative NPV @ 6.84%	-$6,722,320	-$5,886,148	-$4,991,940	-$4,033,591	-$2,921,840	-$1,561,808	-$254,985	$1,000,709	$2,207,276	$3,366,637	$4,480,639	$5,551,057	$6,579,596	$7,567,895	$8,517,527
Cummulative IRR	**-1.51%**	**0.42%**	**2.01%**	**3.35%**	**4.58%**	**5.77%**	**6.68%**	**7.41%**	**7.99%**	**8.48%**	**8.89%**	**9.23%**	**9.53%**	**9.78%**	**10.00%**

SA229 – End of life I&C meter sets

1.1 Project approvals

Table 0.1: Business case SA229 – Project approvals

Prepared by	Muhammad Kashif – Senior Facilities Integrity Engineer
Reviewed by	Alan Creffield – Manager Integrity
Approved by	Michael Iapichello – Head of Engineering and Planning Jason Morony – Head of Networks Operations

1.2 Project overview

Table 0.2: Business case SA229– Project overview

Description of the problem / opportunity	The South Australian gas distribution network has more than 11,000 industrial and commercial (I&C) customers. 690 of these customers are supplied with large meter sets due to the high volume of gas usage. Meter sets are made up of valves, pipework, regulators, fittings and other minor components. While the meters on these sets are changed as per the Meter Replacement Plan, the meter set remains in place, with some installations currently over 40 years old. The replacement of the physical meter is included in our Meter Replacement Plan, however this business case considers the need to refurbish or replace the meter set. In previous periods we have included spend on meter sets to address specific issues such as overpressure, however, we haven't had a program to generally address ongoing end of life meter set assets. We have changed our approach for the next five-year period and have developed a more holistic approach to the various meter set related risks such as overpressure and unregulated bypass lines as opposed to dedicated programs driven by a particular risk. A meter set is considered end of life when it no longer complies with standard design practices relating to safety compliance, or the level of corrosion on the meter set suggests it is likely to fail in the short term and remediation works are no longer going to extend the asset's life. We have established that 460 of our large meter sets need investment to address non-compliance or have reached their end of life with a need to refurbish, modify or replace assets, depending on which option is more economical. While we cannot feasibly address all these meter sets in the next five years, we have conducted a risk-based prioritisation to develop a program that we can deliver over a reasonable period.
Untreated risk	As per risk matrix = Moderate (not ALARP)
Options considered	• **Option 1** – Reactively replace on failure (no upfront capex) • **Option 2** – Address end of life meter sets at current rates ($1.1 million) • **Option 3** – Address end of life meter sets over 10 years (>$3.0 million)
Proposed solution	Option 2 is the proposed solution. This is the optimal balance of achieving risk reduction outcomes and ensuring a deliverable, balanced portfolio of work. We have phased the program over a longer timeframe, with a view to complete the highest risk meter sets as a priority. The proposed option will mitigate the high health and safety, operational and compliance risks associated with meter set deterioration and will also reduce the operational and financial risks of emergency repairs.

Option 1 would result in escalating risks at customer sites and is does not address the primary risk associated with end of life meter sets to as low as reasonably practicable.

Option 3 would require external resources to deliver. Given the significant amount of competing work in utilities expected over the next AA period, as well as our own works program that includes projects relating to pressure regulating equipment, there is a risk that we may not be able to get enough third-party support on this program, or if it is made available, it is likely to be prohibitively expensive.

Estimated cost

The forecast direct cost (excluding overhead) during the next five-year period (July 2026 to June 2031) is $1.1 million.

$'000 Jan 2025	26/27	27/28	28/29	29/30	30/31	Total
I&C meter sets	220	220	220	220	220	**1,101**

Table may not sum due to rounding

Basis of costs

All costs in this business case are expressed in real unescalated dollars at January 2025 unless otherwise stated.

Treated risk

As per risk matrix = Negligible

Alignment to our vision

This project aligns with the *Customer Focussed* and being *A Leading Employer* aspects of our vision as it mitigates the risk to public health and safety, and the safety of our employees.

It also reflects *Operational Excellence* as it ensures security and reliability of gas supply, and balances risk reduction with impact on customers' bills.

Consistency with the National Gas Rules (NGR)

This project complies with the following National Gas Rules (NGR):

NGR 79(1) – The proposed solution is consistent with good industry practice, several practicable options have been considered, and market rates have been tested to achieve the lowest sustainable cost of providing this service.

NGR 79(2) – The proposed capex is justifiable under NGR 79(2)(c)(i) and (ii), as it is necessary to maintain the safety and integrity of services.

NGR 74 – The forecast costs are based on the latest market rate testing and project options consider the asset management requirements as per the Asset Management Strategy. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.

Stakeholder engagement

Feedback from stakeholders is built into our asset management considerations and is an important input when developing and reviewing our expenditure programs. Our customers have told us their top three priorities are price/affordability, reliability of supply, and maintaining public safety. They also told us they expect us to deliver a high level of public safety and are satisfied that this is current practice.

The proposed program of work is designed to ensure the network operates in line with good industry practice, safety standards and compliance requirements, thereby helping maintain a safe and reliable service to our customers. These activities are consistent with stakeholder expectations of our network and the level of service our customers value.

Our delivery profile will deliver the solution with the lowest sustainable cost and therefore minimising the impact on customers' gas bills.

Other relevant documents

- Attachment 9.3: Asset Management Plan
- Attachment 9.5: Meter Replacement Plan
- Attachment 9.6: Procurement Policy & Procedure
- Attachment 9.10: Unit Rates Report
- Attachment 9.11: Risk Management Framework
- Business case SA206: DRS overpressure risk reduction

1.3 Background

I&C metering facilities are made up of the meter unit itself and the meter set assembly which includes the regulators, filters, valves, pipework, fittings and other minor components. Note the meter itself is not within scope of this business case. This business case is for capital works on the **meter sets only**. Replacement of meter units is covered by the Meter Replacement Plan.

Of our 11,000 I&C customers, 686 of our large use customers have meter sets that regulate mains distribution pressure to customer supply pressure and enable the safe and accurate measurement of high volumes of gas.

Meter sets have varying lifespans (20-50 years) depending on their local environment. For example, a meter set that is outside and closer to the coast has a greater risk of corrosion than one in a dedicated metering room within the CBD.

Historically we have managed our meter sets through specific targeted programs addressing key risks as they emerge. This has meant we have not had a general program for meter set refurbishment and replacement.

Over the last 10 years we have made investments in meter sets to mitigate the risk of overpressure events by installing overpressure shutoff valves and regulated bypass lines. The rate of remediation has increased over time to a sustainable level, with an average of 20 meter sets addressed per year, for the last three years. This rate of rectification results in an ongoing program that will address the number of known non-compliant meters over approximately 20 years.

As part of these programs, we now have a better understanding of the condition of our assets and are working to develop a proactive management program that considers the meter sets more holistically.

A meter set is considered end of life when it no longer complies with standard design practices relating to safety compliance, or the level of corrosion on one or more components of the meter set suggests it is likely to fail in the short term and remediation works are no longer able to extend the asset’s life.

In the next five years we will continue to mitigate safety non-compliances such as unregulated bypasses and through a more holistic risk-based approach we will start to more proactively address asset integrity issues such as corrosion before they become a major problem.

1.3.1 Safety non-compliance

As part of our ongoing asset management and maintenance for meter sets we conduct reviews of the site to ensure compliance with current standards and standard industry design practices. This review process includes several aspects. We assess valve, filter and sense line operations to ensure they are functioning correctly and efficiently, as well as evaluate the accuracy of regulating equipment to enable correct gas measurements and control.

Additionally, we inspect equipment designed to manage overpressurisation, ensuring it can effectively handle excess downstream pressure situations. We therefore verify the presence and functionality of adequate regulated bypasses, which are essential to safely facilitate maintenance activities without compromising the continuous supply of services. In having a regulated bypass we are eliminating the need to either interrupt supply or to manually control flows and pressures through valve throttling.

1.3.1.1 Unsuitable bypasses

The type of meter set at each I&C customer's premises varies depending on that customer's load requirements. Most I&C customers have diaphragm style meters without a bypass line (see Figure 0.2). However, our large I&C customers have rotary/turbine meter sets with a bypass line (see Figure 0.1) to allow us to conduct routine maintenance on the meter set at the customer's premises without disrupting supply.

Figure 0.1: I&C rotary/turbine meter set with bypass

Figure 0.2 I&C diaphragm meter set without bypass

The bypass line for our I&C rotary/turbine meter sets typically includes one or two isolation valves that separate the upstream high (350 kPa) or medium (90 kPa) pressure from the downstream customer supply pressure. During maintenance of the duty stream, these bypass line isolation valves can be opened and manually throttled and monitored to maintain gas supply to the customer, while the duty stream on the meter set is shut down.

In 2016 the standard design for I&C rotary/turbine meter sets was modified to include a regulator on the bypass line. This updated design reduces the risk the customer's equipment could become overpressurised when the bypass line is in use.[24] We have been installing new pressure control bypasses, or adding pressure control to existing bypasses, since the standard design was changed. However, we still currently have around 460 meter sets without pressure control on the bypass. We are working to address this risk with a sustainable program that will standardise these larger industrial and commercial meter sets across our network.

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[24] An overpressure incident in the Queensland gas distribution network in June 2019, which was caused by human error during manual throttling, has led us to review our practices in SA. As a short-term risk mitigation, we have changed our maintenance practice on these unregulated bypasses. We now isolate the customer's supply during maintenance. This means no gas is flowing during maintenance and overpressurisation cannot occur.

1.3.1.2 Asset integrity

Corrosion is an ongoing risk for meter sets. The protective coating deteriorates over time due to environmental factors, which leads to corrosion and damage of the meter set pipework, valves and fittings. The corrosion risk for each meter set varies by location, environmental conditions, age and component/configuration type.

If corrosion is left untreated, it can lead to significant or complete replacement of pipework and components. Replacing components typically requires the I&C customer’s gas supply to be isolated, which in many cases would not be practicable and would cause significant disruption to the customer’s commercial operations.

Further, if corrosion is left untreated for long enough, meter set pipework and components can fail and result in an uncontrolled gas release. The proximity of meter sets to customer sites means the consequences of an uncontrolled gas release can be severe, both in terms of public safety and reliability of supply.

Our aim is to refurbish meter sets proactively, before pipework and components become inoperable or do not perform as designed. We refurbish meter sets by on-site grit blasting and reapplying protective paint to the meter set components (valves, pipework, regulators, fittings and other minor components). This helps extend the life of the meter sets and is a critical ongoing program necessary to manage the integrity of the I&C gas supply points on the AGN network.

As part of our ongoing meter set management program, we conduct periodic inspections and maintenance on large meter assemblies and prioritise subsequent treatment based on risk. Where necessary, local areas of peeling or delaminated paint is removed (sanded back) and repainted. This work is conducted by internal operations staff during usual maintenance activities.

Where the level of paint deterioration and/or surface corrosion on a meter set means touching up the paintwork is no longer effective, that meter set is flagged for refurbishment.

1.4 Risk assessment

Risk management is a constant cycle of identification, analysis, treatment, monitoring, reporting and then back to identification (as illustrated in Figure 0.10). When considering risk and determining the appropriate mitigation activities, we seek to balance the risk outcome with our delivery capabilities and cost implications. Consistent with stakeholder expectations, safety and reliability of supply are our highest priorities.

Our risk assessment approach focuses on understanding the potential severity of failure events associated with each asset and the likelihood that the event will occur. Based on these two key inputs, the risk assessment and derived risk rating then guides the actions required to reduce or manage the risk to an acceptable level.

Figure 0.3: Risk management principles

Our risk management framework is based on:

- AS/NZS ISO 31000 Risk Management – Principles and Guidelines
- AS 2885 Pipelines-Gas and Liquid Petroleum
- AS/NZS 4645 Gas Distribution Network Management

The *Gas Act 1997* and *Gas Regulations 2012*, through their incorporation of AS/NZS 4645 and the *Work Health and Safety Act 2012*, place a regulatory obligation and requirement on AGN to reduce risks rated high or extreme to low or negligible as soon as possible (immediately if extreme). If it is not possible to reduce the risk to low or negligible, then we must reduce the risk to as low as reasonably practicable (ALARP).

When assessing risk for the purpose of investment decisions, rather than analysing all conceivable risks associated with an asset, we look at a credible, primary risk event to test the level of investment required. Where that credible risk event results in a risk event rated moderate or higher, we will consider investment to reduce the risk.

Seven consequence categories are considered for each type of risk:

8. **Health & safety** – Injuries or illness of a temporary or permanent nature, or death, to employees and contractors or members of the public
9. **Environment** (including heritage) – Impact on the surroundings in which the asset operates, including natural, built and Aboriginal cultural heritage, soil, water, vegetation, fauna, air and their interrelationships
10. **Operational capability** – Disruption in the daily operations and/or the provision of services/supply, impacting customers
11. **People** – Impact on engagement, capability or size of our workforce
12. **Compliance** – The impact from non-compliance with operating licences, legal, regulatory, contractual obligations, debt financing covenants or reporting / disclosure requirements
13. **Reputation & customer** – Impact on stakeholders' opinion of AGN, including personnel, customers, investors, security holders, regulators and the community
14. **Financial** – Financial impact on AGN, measured on a cumulative basis

Our Risk Management Framework, including definitions, is provided in Attachment 9.11.

The primary risk event identified for end of life large I&C meter sets is that the pipework, or a critical pressure control item, fails due to excessive corrosion that results in downstream customer equipment becoming overpressurised, which can cause a leak within the customer's facility, or within the gas metering room. This can lead to a gas-in-building scenario, which if ignited, can cause injury to the public.

The untreated risk[25] rating is presented in Table 0.4.

Table 0.3: Risk assessment – Untreated risk

Untreated risk	**Health & Safety**	**Environ-ment**	**Operations**	**People**	**Compliance**	**Rep & Customer**	**Finance**	**Risk**
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Moderate (non-ALARP)
Consequence	Significant	Minimal	Minor	Minimal	Minor	Minor	Minimal	
Risk Level	Moderate	Negligible	Low	Negligible	Low	Low	Negligible	

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[25] Untreated risk is the risk level assuming there are no risk controls currently in place. Also known as the 'absolute risk'.

In certain circumstances, including where a meter is located in an enclosed space, or near an ignition source, a gas leak can have major health and safety consequences. Such an event would lead to significant health and safety risks.

As a result, the untreated risk associated with end of life I&C meter sets is rated moderate and is not ALARP.

1.5 Options considered

The options considered are:

- **Option 1** – Reactively replace on failure
- **Option 2** – Address end of life meter sets at current rates
- **Option 3** – Address end of life meter sets over 10 years

These options are discussed in the following sections.

1.5.1 Option 1 – Reactively replace on failure

Under Option 1, we would cease the ongoing overpressure related project and only replace end of life meter sets in an ad hoc way upon failure. Unsuitable bypasses would only be rectified upon the replacement of the meter set on failure, or following an overpressure incident. Corrosion on meter sets would not be addressed until such time the asset fails.

1.5.1.1 Advantages and disadvantages

The advantage of this option is that it would require no uplift in current expenditure or resourcing. A reactive program costs and risks would be dictated by the rate of failures or safety incidents. Over the long term, a reactive program of work is expected to cost more, and therefore would increase network tariffs and the overall resource requirement.

The disadvantages of this option are considerable. In addition to the health and safety risk of the failure of a meter set, there is also a significant disadvantage of leaving unsuitable bypass lines on large customer meter sets. An unsuitable bypass line requires us to isolate customer supply to conduct maintenance to avoid the risk of overpressurisation. The practicality of isolating supply has, and is expected to continue to cause delays and deferral of maintenance for some I&C customers. This will increase the cost of coordinating and undertaking maintenance in the short term, and increase the likelihood of asset failure over the longer term. Moreover, isolating supply causes considerable disruption to customers, many of whom rely on an uninterrupted gas supply to conduct business operations.

1.5.1.2 Cost assessment

There would be no upfront capital cost associated with this option. The capital cost of replacing the I&C meter sets would only be incurred upon failure.

In the short term, this would put downward pressure on gas distribution tariffs and allow resources to be deployed elsewhere. However, over the longer term a reactive asset management approach would increase network tariffs and the overall resource requirement.

Current operating costs associated with I&C meter set maintenance are higher than they otherwise would be if we did not have to isolate supply. This is due to the additional coordination activities and after hours works required to isolate customer.

As a prudent asset manager, we consider the continued isolation of I&C customers, the risks associated with throttling supply and untreated corrosion is not sustainable.

1.5.1.3 Risk assessment

Option 1 does not address the primary risk associated with end of life meter sets. The risk is not changed from the untreated risk (see Table 0.4).

Table 0.4: Risk assessment – Option 1

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Moderate (non-ALARP)
Consequence	Significant	Minimal	Minor	Minimal	Minor	Minor	Minimal	
Risk Level	Moderate	Negligible	Low	Negligible	Low	Low	Negligible	

1.5.1.4 Alignment with vision objectives

Table 0.5 shows how Option 1 aligns with our vision objectives.

Table 0.5: Alignment with vision – Option 1

Vision objective	Alignment
Customer Focussed – Public Safety	N
Customer Focussed – Customer Experience	N
Customer Focussed – Cost Efficient	N
A Leading Employer – Health and Safety	-
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	-
Operational Excellence – Benchmark Performance	N
Operational Excellence – Reliability	N
Sustainable Communities – Enabling Net Zero	-
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	-

This option does not align with our objective of being *Customer Focussed*. It does not address the health and safety risks of a failure of these end of life assets due to corrosion or the need to avoid overpressurisation of the downstream assets. Moreover, as the long term costs of a reactive program are higher, it would not be cost efficient.

Leaving unsuitable bypass lines on meter sets does not align with our strategic pillar of *Operational Excellence* as these meter sets do not meet current industry standard design, and the current practice of isolating customers without suitable pressure control reduces reliability as we will have to continue to isolate customers for routine maintenance.

1.5.2 Option 2 – Address end of life meter sets at current rates

Under this option, we would continue to invest to refurbish or replace meter sets at current rates over the next five years. This will allow us to rectify non-compliant bypass lines and address corrosion where required on around 100 meter sets. The remaining meter sets would be completed during the following periods.

1.5.2.1 Advantages and disadvantages

The advantages of this option are considerable.

This option addresses the highest risk assets to mitigate the health and safety risk of the failure of a meter set. It also ensures these assets meet industry standards as automatically regulated bypass lines will be installed at our highest risk locations. This will prevent the risk of an overpressure event, and allow us to conduct routine maintenance on our assets without isolating supply. The ability to do this work in normal business hours and with internal crews, and while maintaining supply to the customer will ensure works are able to be performed at a lower cost, and without delay. This in turn will reduce the likelihood of asset failure over the longer term.

The disadvantage of this option is that using internal resources only, it will take multiple periods to address all known issues.

1.5.2.2 Cost assessment

The estimated capital cost of rectifying 100 large I&C customer meter sets is $1.1 million (see Table 0.6). This estimate is based on current material and labour rates for meter set refurbishment and replacement activities conducted to date.

Table 0.6: Cost assessment - Option 2, $'000 January 2025

	26/27	27/28	28/29	29/30	30/31	Total
Meter set compliance and corrosion	220	220	220	220	220	**1,101**
Total	**220**	**220**	**220**	**220**	**220**	**1,101**

Table may not sum due to rounding

Option 2 will also reduce costs associated with the coordination of maintenance activities and additional expenditure of operating outside of normal operating hours over the longer term.

1.5.2.3 Risk assessment

Option 2 reduces the untreated risk rating from moderate to low for the 100 completed sites.

Table 0.7: Risk assessment – Option 2

Option 2	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Low
Consequence	Significant	Minimal	Minor	Minimal	Minor	Minor	Minimal	
Risk Level	Low	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	

Addressing end of life meter sets reduces the likelihood of an asset failure. While we have not addressed the entire end of life population, the likelihood of a health and safety event remains remote. Option 2 also eliminates the need to isolate the I&C customer for maintenance.

This results in an overall risk rating of Low.

1.5.2.4 Alignment with vision objectives

Table 0.8 shows how Option 2 aligns with our vision objectives.

Table 0.8: Alignment with vision – Option 2

Vision objective	Alignment
Customer Focussed – Public Safety	Y

Vision objective	Alignment
Customer Focussed – Customer Experience	Y
Customer Focussed – Cost Efficient	-
A Leading Employer – Health and Safety	Y
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	-
Operational Excellence – Benchmark Performance	Y
Operational Excellence – Reliability	-
Sustainable Communities – Enabling Net Zero	-
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	-

Option 2 aligns with the *Customer Focussed,* and being *A Leading Employer* aspects of our vision, as proactive remediation of large I&C meter sets will help maintain reliability of supply and mitigate the risk of public safety incidents. Staff working directly on the meter set would have a safe working environment and the downstream customer would be safe from elevated operating pressures in the network.

The proposed solution is also reflective of *Operational Excellence* as mitigating the risk through meter set augmentation where possible, as opposed to replacement is the lowest sustainable cost option. It will also reduce the operational and financial risks of emergency repairs. This option uses internal resources to deliver the program, albeit over a longer period. We consider this approach balances the risk reduction with the impact on customer bills.

1.5.3 Option 3 – Address end of life meter sets over 10 years

Under this option, we would take the same approach as Option 2, but would engage a third-party contractor to allow us to undertake the works more quickly. Under this option, we would increase the program to double the program. To achieve this increase in work, we would need to engage third-party contractors to support the internal crew.

1.5.3.1 Advantages and disadvantages

This option has the same advantages as Option 2, but will allow us to remediate the risks associated with end of life meter sets more quickly.

The disadvantage is that the cost of this option is much higher than Option 2. Not only are the costs brought forward, affecting customers' bills over the next period, but we would also need to engage third-party providers.

Over the next period, there is a significant amount of construction work planned for South Australia both within AGN and for other utilities such as SA Water and SA Power Networks. This means we would be competing against multiple other businesses to get contractors. Should we be able to contract sufficient resources to complete the increased work program, it is likely to be prohibitively expensive.

1.5.3.2 Cost assessment

The estimated capital cost of installing pressure regulation on 230 meter facilities over the next five years is at least $3.0 million (see Table 0.9). This estimate is based on the current material and internal labour rates for I&C installations of meter sets of comparable size. We have applied a conservative 20% uplift for those proposed to be delivered by third-parties.

Table 0.9: Cost assessment - Option 2, $'000 January 2025

	26/27	27/28	28/29	29/30	30/31	Total
Meter set compliance and corrosion	506	506	506	506	506	**2,530**
Contractor uplift	101	101	101	101	101	**506**
Total	**607**	**607**	**607**	**607**	**607**	**3,036**

Table may not sum due to rounding

This option would deliver the same safety risk reduction as Option 2, but at a higher cost to customers due to the higher volume and need for third-party support at a higher per unit rate.

1.5.3.3 Risk assessment

Option 3 reduces the untreated risk associated with end of life I&C meter sets from moderate to negligible (see Table 0.10).

Table 0.10: Risk assessment – Option 3

Option 3	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Rare	Rare	Rare	Rare	Rare	Rare	Rare	Negligible
Consequence	Significant	Minimal	Minor	Minimal	Minor	Minor	Minimal	
Risk Level	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	

Option 3 achieves the a higher risk reduction than Option 2 as the work performed is identical but on the total population of identified end of life meter sets.

1.5.3.4 Alignment with vision objectives

Table 0.11 shows how Option 3 aligns our vision objectives.

Table 0.11: Alignment with vision – Option 3

Vision objective	Alignment
Customer Focussed - Public Safety	Y
Customer Focussed – Customer Experience	Y
Customer Focussed – Cost Efficient	N
A Leading Employer – Health and Safety	Y
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	-
Operational Excellence – Benchmark Performance	N
Operational Excellence – Reliability	-
Sustainable Communities – Enabling Net Zero	-
Sustainable Communities – Environmentally Focussed	-
Sustainable Communities – Socially Responsible	-

Option 3 partially aligns with the *Customer Focussed* aspect of our vision, as proactive risk mitigation of I&C meter facilities will help maintain reliability of supply and mitigate the risk of public and customer safety incidents. However, this option is not cost efficient and does not reflect *Operational Excellence* as it is more than twice the cost of Option 2, while delivering few additional benefits.

1.6 Summary of cost benefit assessment

Table 0.15 presents a summary of how each option compares in terms of the estimated cost, the residual risk rating, and aligning with our objectives.

Table 0.12: Summary of costs and benefits

Option	Estimated cost	Treated residual risk rating	Alignment with vision objectives
Option 1: Replace on failure	No upfront capex	Moderate – not ALARP	This option does not align with our vision objectives
Option 2: Risk based prioritisation	$1.1 million	Low	This option provides the greatest risk reduction and aligns with all relevant vision objectives
Option 3: Complete all known	>$3.0 million	Negligible	This option would achieve safety objectives, however it would not align with our objective to achieve *Operational Excellence* or be cost efficient, as the cost of Option 3 is more than double Option 2

1.7 Proposed solution

Option 2 is the proposed solution. This is the optimum balance of achieving risk reduction outcomes and ensuring a deliverable, balanced portfolio of work. We have phased the program over a longer timeframe, with a view to complete the highest risk meter sets as a priority. The proposed option will mitigate the moderate health and safety risks associated with meter set deterioration and will also reduce the operational and financial risks of emergency repairs.

1.7.1 Why is the recommended option prudent?

Option 2 is proposed because:

- It addresses the risks associated with corrosion and overpressurisation related to large I&C customer meter sets from moderate to low at the highest risk locations
- It represents a standard engineering practice, as supported by AS/NZS 4645.1 and AS 2885.1
- It reduces this risk to an acceptable level for a reasonable investment level:
  - Option 1 does not mitigate the identified compliance, and health and safety risks so is not considered an appropriate long term outcome
  - While Option 3 may reduce the identified risk further than Option 2 it is at a significantly higher overall cost
- It is consistent with customer and stakeholder requirements and our vision, by being *Customer Focussed* and achieving *Operational Excellence*

- The delivery of the scope of works is achievable by internal resources in the time frame envisaged, thereby avoiding unnecessary costs associated with third-party contractors

1.7.2 Estimating efficient costs

The unit rates used for all projects managed within this program include the internal labour, external labour and materials/other costs forecast.

Key assumptions which have been made in the cost estimation for this project include:

- All I&C meter sets will be completed over multiple regulatory periods, with 100 completed during the next five years
- Costs are based on historical expenditure noting that these works are not new, with labour rates based on work breakdown structure of activities, and material rates based on historical costs for similar materials
- The number of meter sets we can refurbish vs replace is unknown, so a historical average unit rate has been used for the purpose of this forecast
- The works required to be completed to refurbish or replace a meter set is likely to be comparable irrespective of the driver (i.e. corrosion or non-compliance)
- Estimates derived from contractual rates of vendors are utilised
- Resource cost based on other similar projects ongoing at present or in previous periods
- Original equipment manufacturer contractual rates for spares and labour that are part of our services agreements are utilised

presents a breakdown of the cost estimate by cost category.

Table 0.13: Project cost estimate, by cost category, $'000 January 2025

	26/27	27/28	28/29	29/30	30/31	Total
Materials	82	82	82	82	82	**410**
Labour	138	138	138	138	138	**691**
Total	**220**	**220**	**220**	**220**	**220**	**1,101**

Tables may not sum due to rounding

1.7.3 Consistency with the National Gas Rules

In developing these forecasts, we have had regard to NGR 79 and NGR 74.

1.6.3.0.1 NGR 79(1)

The proposed solution is prudent, efficient, consistent with accepted and good industry practice and will achieve the lowest sustainable cost of delivering pipeline services:

- **Prudent** – The expenditure is necessary in order to deliver gas safely and reliably to the downstream network. The proposed risk treatment is consistent with accepted industry practice and current design standards and is proven to address the risk associated with end of life meter sets. Several practicable options have been considered to address the risk. The proposed expenditure is of a nature that would be incurred by a prudent service provider.

- **Efficient** – The forecast expenditure is based on historical average actuals. The proposed expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur. The project is being delivered at an achievable rate of installation using internal resources.

- **Consistent with accepted and good industry practice** – The proposed expenditure follows good industry practice by ensuring existing safety risks are addressed to ALARP and in line with current industry practice and design standards. The proposed capital expenditure is therefore such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice.

- To achieve the **lowest sustainable cost of delivering pipeline services** – The sustainable delivery of services includes reducing risks to ALARP while maintaining reliability of supply. We have also spread the works over a reasonable timeframe that balances risk reduction with deliverability and the impact on customers' bills.

1.6.3.0.2 NGR 79(2)

The proposed capex is justifiable under NGR 79(2)(c)(i) and (ii), as it is necessary to maintain the safety and integrity of services. Retaining end of life meter sets for large I&C customers is an unacceptable safety risk for customers and our staff, and may lead to network integrity issues, disruption to customer supply and potential uncontrolled release of gas.

Consistent with the Asset Management Strategy, and as outlined in this business case, current industry practice, to ensure suitable meter sets are provided for all large I&C customers will allow us to provide a level of service consistent with industry and design standards, consistent with customer expectations.

1.6.3.0.3 NGR 74

The forecast costs are based on the latest market rate testing and project options consider the asset management requirements as per the Asset Management Strategy. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.

Appendix A Comparison of risk assessments

Untreated risk	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Moderate (non-ALARP)
Consequence	Significant	Minimal	Minor	Minimal	Minor	Minor	Minimal	
Risk Level	Moderate	Negligible	Low	Negligible	Low	Low	Negligible	

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Moderate (non-ALARP)
Consequence	Significant	Minimal	Minor	Minimal	Minor	Minor	Minimal	
Risk Level	Moderate	Negligible	Low	Negligible	Low	Low	Negligible	

Option 2	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Remote	Remote	Remote	Remote	Remote	Remote	Remote	Low
Consequence	Significant	Minimal	Minor	Minimal	Minor	Minor	Minimal	
Risk Level	Low	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	

Option 3	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Rare	Rare	Rare	Rare	Rare	Rare	Rare	Negligible
Consequence	Significant	Minimal	Minor	Minimal	Minor	Minor	Minimal	
Risk Level	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	

SA242 – Network adaptation project

1.1 Project approvals

Table 0.1: SA242 Network adaptation project – Project approvals

Prepared by	Simar Thind Engineer – Low Carbon Future
Reviewed by	Michele Tanti – Senior Asset Management Engineer
Approved by	Troy Praag – Head of Network Strategy and Planning

1.2 Project overview

Table 0.2: SA242 Network adaptation project – Project overview

Description of the problem / opportunity	AGN is commencing adaptation of the gas distribution network to support the transition to a lower-emissions future by enabling the distribution of renewable gases, such as biomethane and up to 20% hydrogen blends. The energy transition is happening across Australia and the world. Gas and electricity are vital to people's energy needs and will remain so for decades to come. Many industries cannot electrify easily (e.g. heavy industry, chemical, food processing) and residential customers still value and rely on a gas supply to their home appliances. Just as the electricity energy sector is decarbonising electrons by shifting electricity generation towards renewables, the gas sector must also seek to decarbonise gas molecules by shifting to renewables such as biomethane and hydrogen blends. A network capable of transporting renewable gas would be a major milestone in South Australia's energy transition. The established distribution pipeline network is an extensive, high value and versatile asset, supplying gas to more than 480,000 homes and businesses, many of which continue to value gas as their preferred energy source. As AGN moves towards its vision of net zero by 2050 or sooner, the existing gas network will continue to support consumers by delivering renewable energy solutions without changing how they use gas in their homes and businesses. We recognise that the shift to renewable gas will take time, and while the pathway to a decarbonised pipeline network is still evolving, AGN's plan is for a phased and focused program of targeted investment – estimated at up to $6.3 million capex and opex over the next five years – to adapt parts of our network where we know renewable gas is likely to be introduced within the next decade. The proposed investment is to: • Replace pipeline components in parts of the network where hydrogen/hydrogen blend injections are planned, with components that are compatible with these new renewable gases • Undertake hardness testing and develop welding procedures for safe working • Research impacts of hydrogen in our network along with any mitigation measures required This work will set an important precedent for decarbonisation of gas molecules, allowing the sector to understand the pathway to net zero and how the distribution pipeline network can support the energy transition. This conservative investment will also allow AGN to identify the most efficient and prudent program for network adaptation, to ensure it remains open and accessible to renewable gas suppliers. Ultimately, this approach will benefit all network users by preserving access to our network and supporting consumer choice in how they meet their energy needs.
Untreated risk	As per risk matrix = High
Options considered	• **Option 1** – Phased adaptation of the network at strategic locations over 10 years ($6.3 million) • **Option 2** – Complete adaptation of the network over 5 years ($10.3 million)

- **Option 3** – No proactive network adaptation ($247k)

Proposed solution

Option 1 is the proposed solution. Although Option 2 allows hydrogen injection at any location in the network, we have taken a pragmatic view and not included hydrogen blends at locations with less certainty. If opportunities arise for hydrogen blends to occur in other areas of the network than currently foreseen, we will make a case-by-case assessment.

Option 3 is not tenable from a risk perspective as there may be reactive failure of key pressure control assets as well as significant reputational risks if we are not ready in a timely manner. Option 1 is phased over 5 years and will set the network up for the short term, allowing us to apply lessons learned and project optimisations for the remainder of the program in the next AA regulatory period.

Estimated cost

The forecast direct cost (excluding overhead) during the next AA period (July 2026 to June 2031) is $6.3 million.

$'000 Jan 2025	26/27	27/28	28/29	29/30	30/31	Total
Capex	1,030	1,330	1,240	1,240	1,250	6,090
Opex	138	82	27	-	-	247
Total	1,168	1,412	1,267	1,240	1,250	6,337

Basis of costs

All costs in this business case are expressed in real unescalated dollars at January 2025 unless otherwise stated.

Treated risk

As per risk matrix = Low

Alignment to our vision

The preferred option aligns with the *Customer Focussed* aspect of our vision as adapting the gas network for hydrogen blends means customers who rely on and value our network can continue to be served by it but consume lower carbon gas. Cost efficiency is achieved through phased infrastructure upgrades, leveraging existing assets where possible. We are also aligned with *Operational Excellence* as the proposed investment helps ensure hydrogen blends are introduced in a way that supports network integrity and reliability, by avoiding areas where they may pose risks to infrastructure.

Most significantly, the investment is aligned with our objective of enabling *Sustainable Communities*. Adapting our network to be able to distribute greener gas molecules will make an important contribution to AGN achieving its net zero targets, and will give customers the opportunity to reduce their carbon emissions through alternative means.

Consistency with the National Gas Rules (NGR)

NGR 79(1) – The proposed solution is consistent with good industry practice, several practicable options have been considered, and market rates have been tested to achieve the lowest sustainable cost of providing this service.

NGR 79(2) – The proposed capex is justifiable under NGR 79(2)(c)(i)(ii) and (v), as it is necessary to maintain and improve the safety of services and contributes to emissions targets.

NGR 74 – The forecast costs are based on the latest estimates, costs and operational experience. The estimate has therefore been arrived at on a reasonable basis and represents the best estimate possible in the circumstances.

Stakeholder engagement

We are committed to operating our networks in a manner that is consistent with the long-term interests of our customers. To facilitate this, we conduct regular stakeholder engagement to understand and respond to the priorities of our customers and stakeholders. Feedback from stakeholders is built into our asset management considerations and is an important input when developing and reviewing our expenditure programs.

Our customers have told us their top three priorities are price/affordability, reliability of supply, and maintaining public safety. They also told us they value decarbonisation and it was important to them, and they expect us to pursue greener options where prudent and affordable to do so.

The proposed investments aligns with customers' needs as the proposed network adaptation means pipeline assets will remain safe when hydrogen blends enter the system. It also reflects a prudent and conservative level of expenditure that will

	ultimately allow all consumers to remain connected to the distribution network while using cleaner, greener gas. The decarbonisation of the energy sector, along with stakeholders interest in renewable gas, remains the focus of ongoing discussion and research. For example, South Australia's Hydrogen Action Plan sets a blueprint for how the SA Government supports the growth of the emerging renewable gas sector, with it's primary objective to "Scale-up renewable hydrogen production for export and domestic consumption". Furthermore, in recent South Australian customer engagement workshops, key findings were: • Clean energy and reducing carbon emissions is an imperative for the majority of customers. • 87% of customers view climate change and reducing carbon emissions as important or very important. • 89% of customers support AGN's proposed approach to preparing our networks for renewable gas. Based on this feedback, it is clear our gas distribution networks will have an important role to play in South Australia's energy transition, and that customers still value gas services. We will therefore continue to pursue prudent and efficient ways to optimise our network for renewable gas, while aiming to minimise any impact on customers' bills.
Other relevant documents	• Asset Management Strategy – AGN South Australia Networks – 420-PL-AM-0010 • Australian Hydrogen Council - 10% Hydrogen Distribution Networks South Australia Feasibility Study • AGIG Network Adaptation Strategy - Renewable Gas

1.3 Background

South Australia is in the midst of an ongoing energy transition. Consumers are seeking greener forms of power, and there is a multi-sector push towards decarbonised energy.

The energy transition applies to both electricity and gas. While electrification of homes and businesses is a major focus of the transition, gas remains a vital part of Australia's energy mix as fuel source for generation, industrial processing, and space/water heating. Many businesses, such as minerals production, food processing, heavy manufacturing, and chemicals processing cannot electrify easily, and will continue to rely on gas over the coming decades. Similarly, many residential customers continue to value a gas connection and may choose not to fully electrify.

Given a broad cross section of consumers will continue to use gas, an important part of the energy transition is to decarbonise gas molecules. Just as there is a focus on replacing fossil-fuel generated electricity with renewable electrons produced via wind and solar, there is an opportunity to shift towards production of renewable gas molecules in the form of biomethane, hydrogen and hydrogen blends. When these projects have reached sufficient scale and are ready to supply renewable gas to consumers, it is vital the gas pipeline network is ready to transport it.

1.3.1 Renewable gas projects

Governments and private sector businesses (including AGN) are pursuing renewable gas. Several projects and hydrogen studies are currently underway across the country, with the aim of introducing renewable gases and/or hydrogen blends into the established pipeline networks, such as Western Sydney Hydrogen Hub, ATCO Hydrogen Community Blending, Malabar Biomethane Injection Plant, Hydrogen Park South Australia (HyP SA), Hydrogen Park Gladstone (HyP Gladstone) and Hydrogen Park Murray Valley (HyP MV).

In May 2023 the Australian Hydrogen Council published a report titled *10% Hydrogen Distribution Networks South Australia Feasibility Study - Assessing the feasibility of delivering 10% renewable hydrogen in South Australia's gas distribution networks*[26]. The report shows it is technically and economically feasible to use existing gas infrastructure for scaled hydrogen distribution and outlined the most credible locations for hydrogen injections to the AGN's gas distribution system (see Figure 0.1).

Figure 0.1: Credible locations for hydrogen injection to the distribution system, Australian Hydrogen Council report.

Since the report was published, location 19 on the above map – the Hydrogen Park Adelaide (HyP Adelaide) project has progressed significantly. HyP Adelaide is centered at SA Water's Bolivar wastewater treatment plant in northern Adelaide. It aims to establish a 60-megawatt alkaline electrolysis facility that will produce up to 16.7 tonnes of renewable hydrogen per day.

The primary goal of HyP Adelaide is to help decarbonise the region's gas supply by blending up to 20% hydrogen by volume into Adelaide's existing gas distribution network. This blend will serve over 450,000 customers. The project plans to supply hydrogen directly to the nearby Bolivar Power Station, where it will be blended into the gas supply at up to 25% by volume.

HyP Adelaide will produce 16.7 tonnes of hydrogen per day, or 6,096 tonnes of hydrogen over the year when fully operational. This equates to approximately 40,000 tonnes of CO_2 emissions avoided.

Beyond residential and power generation uses, HyP Adelaide will also support industrial decarbonisation through the sale of renewable gas certificates and direct hydrogen supply.

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[26] AHC - 10% Hydrogen Distribution Networks South Australia Feasibility Study - Australian Renewable Energy Agency (ARENA)

The project includes a 7 km pipeline to transport hydrogen to the Gepps Cross city gate and features on-site hydrogen storage to ensure flexible network injection.

The project is expected to commence commercial operations in the second half of 2028.

1.3.2 Network adaptation to accommodate renewable gas

AGN forecasts investing approximately $10 million over 10 years to adapt the distribution pipeline network so that it is ready for the introduction of renewable gas and hydrogen blends of up to 20%.

We recognise that the shift to renewable gas will take time, with the progress of the hydrogen sector slowing down over the past 12 months. However, renewable gas remains a viable option and projects like HyP Adelaide will continue to mature, in line with our plan for a phased program of targeted investment – estimated at up to $6.3 million capex and opex over the next five years – to adapt parts of our network where we know renewable gas is likely to be introduced within the next decade.

The proposed investment over the next five years is to:

- Replace pipeline components in parts of the network where hydrogen/hydrogen blend injections are planned, with components that are compatible with these new renewable gases.
- Undertake hardness testing and develop welding procedures for safe working.
- Research any further impacts of hydrogen in our network along with any mitigation measures required.

Most importantly, we are aligning our adaptation plans with the pace of change and will continue to do so throughout the upcoming AA regulatory period. Our aim is to stay just ahead of the renewable gas program, only installing hydrogen-compatible components when and where they are needed, starting with the HyP Adelaide network area. As more renewable gas projects develop, we will work with proponents to identify the timing and location of renewable gas injection and adapt our network assets to suit.

The capital and operating expenditure program has been developed in accordance with the AGIG Network Adaptation Strategy - Renewable Gas AGIG-SP-0001, with the objective of adapting the AGN gas distribution network to transport renewable gas in a manner that is:

- A realistically phased level of investment, consistent with achieving the lowest sustainable cost of transitioning to renewable gases and foreseeable blends of gases.
- Reflective of the locations that renewable gas will enter the network in the next ten years.
- Maintains the safety risk at an acceptable level.
- Aligned with the network vision of facilitating 20% renewable gas by 2030, and to facilitate the transport of fully decarbonised, or net zero, gas energy solutions by no later than 2050, with year 2040 identified as a stretch target.

Note: renewable gas component replacements being conducted as part of ongoing asset replacement strategies such as the mains or regulator replacement programs are not included in this Network Adaptation Plan. This plan relates to proactive replacement of components outside of scheduled end-of-life replacement/upgrade.

We consider this relatively conservative investment program will set an important precedent for ongoing decarbonisation of gas molecules. It will allow industry, governments and potential renewable gas proponents to understand the pathway to net zero and how renewable gas the distribution pipeline network can underpin the energy transition. This investment will allow AGN to identify the most efficient and prudent program for network adaptation, to ensure the network is not a barrier to entry for renewable gas suppliers. Ultimately, all network users will benefit, as it means consumers will continue to benefit from a network connection and have choice in their energy supply.

1.4 Risk assessment

Risk management is a constant cycle of identification, analysis, treatment, monitoring, reporting and then back to identification (as illustrated in Figure 0.10). When considering risk and determining the appropriate mitigation activities, we seek to balance the risk outcome with our delivery capabilities and cost implications. Consistent with stakeholder expectations, safety and reliability of supply are our highest priorities.

Our risk assessment approach focuses on understanding the potential severity of failure events associated with each asset and the likelihood that the event will occur. Based on these two key inputs, the risk assessment and derived risk rating then guides the actions required to reduce or manage the risk to an acceptable level.

Figure 0.2: Risk management principles

Our risk management framework is based on:

- AS/NZS ISO 31000 Risk Management – Principles and Guidelines
- AS 2885 Pipelines-Gas and Liquid Petroleum
- AS/NZS 4645 Gas Distribution Network Management

The Gas Act 1997 and Gas Regulations 2012, through their incorporation of AS/NZS 4645 and the Work Health and Safety Act 2012, place a regulatory obligation and requirement on AGN to reduce risks rated high or extreme to low or negligible as soon as possible (immediately if extreme). If it is not possible to reduce the risk to low or negligible, then we must reduce the risk to as low as reasonably practicable (ALARP).

When assessing risk for the purpose of investment decisions, rather than analysing all conceivable risks associated with an asset, we look at a credible, primary risk event to test the level of investment required. Where that credible risk event results in a risk event rated moderate or higher, we will consider investment to reduce the risk.

Seven consequence categories are considered for each type of risk:

- **Health & safety** – injuries or illness of a temporary or permanent nature, or death, to employees and contractors or members of the public
- **Environment** (including heritage) **–** impact on the surroundings in which the asset operates, including natural, built and Aboriginal cultural heritage, soil, water, vegetation, fauna, air and their interrelationships
- **Operational capability –** disruption in the daily operations and/or the provision of services/supply, impacting customers
- **People –** impact on engagement, capability or size of our workforce

- **Compliance –** the impact from non-compliance with operating licences, legal, regulatory, contractual obligations, debt financing covenants or reporting / disclosure requirements
- **Reputation & customer –** impact on stakeholders' opinion of AGN, including personnel, customers, investors, security holders, regulators and the community
- **Financial –** financial impact on AGN, measured on a cumulative basis

Note that risk is not the sole determinant of what investment is required in our network. Many other factors such as growth, cost, efficiency, sustainability and the future of the network are also considered when we develop engineering solutions. The risk management framework provides a valuable tool to manage our assets, and prioritise our works program, however, it is not designed to provide a binary (yes/no) trigger for investment.

The risk being considered is that hydrogen producers are ready to inject into the network, but the network isn't ready. This would lead to several adverse consequences.

If hydrogen is injected into the network without the appropriate adaptation, there is a major risk that incompatible elastomers and/or metal at a high-pressure regulating site could fail. This would lead to loss of supply to >10,000 customers as well as major compliance risks if AGN is found to have breached its Safety Case, which requires all risks to be managed to a reasonable level (as low as reasonably practicable or ALARP). Hydrogen in an incompatible network may also lead to a significant safety incident if the network failure causes property damage or serious harm.

Even if hydrogen is not injected in the network due to readiness constraints, it presents a significant reputational and customer-confidence risk. Without network adaptation, customers remain reliant on non-renewable gas, undermining national decarbonisation targets and delaying South Australia's progress towards net zero. Furthermore, if proponents are waiting to supply renewable gas but we are unable to connect them due to readiness constraints, it will severely undermine public and investor confidence in our business, leading to sustained customer dissatisfaction and negative media coverage. We are already seeing this lack of stakeholder confidence in the electricity sector, with renewable energy proponents unable to secure an electricity network connection and becoming increasingly frustrated with the poor connection process.[27]

A reactive approach to network adaptation would also lead to a significant financial risk. Delaying investment and adaptations until hydrogen blends are imminent would significantly increase project costs, due to compressed timeframes and limited availability of internal and external resources.

The overall untreated risk is summarised in the following table.

Table 0.3: Risk rating - untreated risk

Untreated	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Significant	Minimal	Major	Minor	Major	Major	Significant	
Risk Level	Moderate	Negligible	High	Low	High	High	Moderate	

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[27] For example: https://reneweconomy.com.au/grid-problems-now-the-biggest-turnoff-for-renewable-energy-investment-in-australia-73144/ and https://mccullough.com.au/2024/05/07/challenges-impacting-the-delivery-of-renewable-energy-projects/

1.5 Options considered

The following options have been identified:

- **Option 1** – Phased adaptation of the network at strategic locations over 10 years

  Upgrade components in strategic locations of the AGN SA network ready for a renewable gas with up to 20% hydrogen blend by 2031, and continue ongoing research into the safe transition of increasing renewable gas volumes ($6.3 million).

- **Option 2** – Complete adaptation of the network over 5 years.

  Upgrade all components across the AGN SA network ready for up to a 20% hydrogen blend by 2031, and continue ongoing research into the safe transition of increasing renewable gas volumes ($10.3 million).

- **Option 3** – No proactive network adaptation

  Inject hydrogen into the network without network adaptation investment. Continue ongoing research into the safe transition to renewable gas ($246.7k).

A summary of the scope of each option is provided in the following table.

Table 0.4: Options Analysis - scope summary

Program	Option 1	Option 2	Option 3
Hazardous Area Equipment	No Hazardous area equipment upgrades needed in this current AA period.		
Replace incompatible parts	66 of 129 identified incompatible parts	129 of 129 identified incompatible parts	N/A
Weld procedures	28 of 41 identified Steel Pipelines	41 of 41 identified Steel Pipelines	N/A
Weld hardness testing	28 of 41 identified Steel Pipelines	41 of 41 Steel Pipelines identified	N/A
Further assessment or investigation	Program Included	Program Included	N/A
Transmission pipeline (TP) compatibility assessment	Program included in all options		
Hazardous areas extents	Program included in all options		
Document updates	Program included in all options		
Further assessment or investigation required	Risk assessments for components including nickel alloys, untested aluminium alloys or elastomers included.	Full program included as per Options 1 & 3, + PRS Amendments	Risk assessments for components including nickel alloys, untested aluminium alloys or elastomers included.
Capex (‘000)	6,090	9,544	N/A
Opex (‘000)	247	766	247
Totex (‘000)	**6,337**	**10,310**	**247**

Under all three options we will continue to investigate the costs, benefits and technical implications of transitioning to renewable gas up to and including 100% hydrogen.

1.5.1 Option 1 - Phased adaptation of the network at strategic locations over 10 years

Under Option 1, we will take the strategic approach of focusing on those parts of the network most likely to have renewable gas hydrogen blends first. Option 1 therefore represents a more conservative work program than Option 2, with a lower number of assets assessed and replaced.

1.5.1.0 Advantages and disadvantages

A ten-year plan to adapt the gas network with a start at locations that are more certain to receive hydrogen blends over the next five years offers strategic advantages. It allows for targeted investment, reducing upfront costs and aligning upgrades with actual hydrogen deployment. This approach supports workforce planning, allows low carbon gas to be distributed in a timely manner and also enables learning from early-stage implementations to inform future phases.

The program demonstrates a clear commitment to decarbonisation, whilst maintaining public safety, and predominantly uses existing infrastructure to deliver a cost-effective solution. However, this longer timeline still carries some risk as delaying full network readiness could respectively limit hydrogen's scalability and therefore progress toward net zero (in the short to mid-term).

There's also potential for regional inequity, where some communities benefit from lower carbon gases earlier than others. There is an increased risk of regulatory changes over a longer period of time that may adversely affect the project, potentially increasing long-term costs.

1.5.1.1 Cost assessment

Table 0.5 provides a breakdown of forecast Capex for Option 1.

Table 0.5: Forecast Capex - Option 1 $'000 January 2025

Title	2026/27	2027/28	2028/29	2029/30	2030/31	Total
Hazardous area equipment	-	-	-	-	-	-
Replace incompatible parts	330	330	-	-	-	660
Weld procedures & weld hardness testing	700	850	1240	1240	1250	5,280
Pipeline repair equipment	-	150	-	-	-	150
Total	**1,030**	**1,330**	**1,240**	**1,240**	**1,250**	**6,090**

Table 0.6 provides a breakdown of forecast opex for Option 1.

Table 0.6: Forecast Opex - Option 1 $'000 January 2025

Title	2026/27	2027/28	2028/29	2029/30	2030/31	Total
TP compatibility assessment	32	-	-	-	-	32
Hazardous areas extents	52	52	-	-	-	104

Document updates	30	30	27	-	-	87
Further assessment or investigation required	24	-	-	-	-	24
Total	**138**	**82**	**27**	**-**	**-**	**247**

1.5.1.2 Risk assessment

Under Option 1, the sections of the network that will receive renewable gas first will be made compatible, therefore the likelihood of the identified loss of supply and compliance risk-events (e.g. Safety Case breach) occurring reduces to rare. This results in an overall risk assessment of low.

Table 0.7: Risk assessment – Option 1

Option 1	Health & Safety	Environment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Rare	Rare	Rare	Rare	Rare	Rare	Rare	Low
Consequence	Significant	Minimal	Major	Minor	Major	Significant	Major	
Risk Level	Negligible	Negligible	Low	Negligible	Low	Negligible	Low	

1.5.1.3 Alignment with vision objectives

Table 0.8 shows how Option 1 aligns with our vision objectives.

Table 0.8: Alignment with vision – Option 2

Vision objective	**Alignment**
Customer Focussed - Public Safety	Y
Customer Focussed – Customer Experience	-
Customer Focussed – Cost Efficient	Y
A Leading Employer – Health and Safety	-
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	-
Operational Excellence – Benchmark Performance	-
Operational Excellence – Reliability	Y
Sustainable Communities – Enabling Net Zero	Y
Sustainable Communities – Environmentally Focussed	Y
Sustainable Communities – Socially Responsible	Y

Option 1 aligns with the *Customer Focussed* aspect of our vision as adapting the gas network for hydrogen blends means customers who rely on and value our network can continue to be served by it but consume lower carbon gas. Cost efficiency is achieved through phased infrastructure upgrades, leveraging existing assets where possible.

Option 1 also aligns with *Operational Excellence* as the proposed investment mitigates the risk of hydrogen blends being in areas of the network where they damage supply infrastructure and affect reliability.

Option 1 is aligned with our objective of enabling *Sustainable Communities*. Adapting our network to be able to distribute greener gas molecules will make an important contribution to AGN achieving its net zero targets and will give customers choice to meet their energy needs.

1.5.2 Option 2 – Complete adaptation of the network over 5 years

Under Option 2, we will identify all components that require proactive replacement to be compatible with renewable gas that includes 20% hydrogen blends, and aim to replace them all during the next 5 year period (2026 to 2031). This includes replacing incompatible parts (certain metallic valves and regulators) and testing weld hardness and procedures.

This would be an exhaustive program, designed to get the entire network ready for renewable gas with hydrogen[28] blends. This will enable renewable gas to be introduced anywhere in the distribution system. Option 2 would also include opex to continue assessing hazardous area extents, updating key documentation to reflect renewable gas asset management, and assessing hydrogen compatibility with transmission pressure pipelines.

The program of works is forecast to be completed before the phased introduction of a renewable gas with 20% hydrogen blend. To best position the project for deliverability success we propose the program output steadily increases over the period.

1.5.2.0 Advantages and disadvantages

Adapting the entire gas network for hydrogen within five years offers the advantage of future-proofing infrastructure ahead of demand. It ensures uniform readiness, simplifies long-term planning. Full network completion ensures the gas network does not become a short term constraint in the pathway for suppliers and customers to distribute and access lower carbon emission gas. A faster adaptation also enables the workforce to accelerate skills development.

However, this approach has higher upfront capital costs and may result in underutilised assets for several years, as hydrogen rollout lags behind infrastructure readiness. There's also an inefficiency risk by investing in areas that may not receive hydrogen as initially planned.

Accelerating implementation may also put additional pressure on both internal and external resources, which may result in less robust planning or higher contracting costs.

While a five-year plan ensures preparedness and demonstrates strong climate leadership, it requires careful risk management and carries a risk of overinvestment that may not align with hydrogen supply timelines.

1.5.2.1 Cost assessment

Table 0.9 provides a breakdown of forecast capex for Option 2.

Table 0.9: Forecast Capex - Option 2 $'000 January 2025

Title	2026/27	2027/28	2028/29	2029/30	2030/31	Total
Hazardous area equipment	-	-	-	-	-	0

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[28] Excluding assets scheduled for replacement as part of ongoing end-of-life replacement programs.

Title	2026/27	2027/28	2028/29	2029/30	2030/31	Total
Replace incompatible parts	350	450	162	161	561.2	1684.2
Weld procedures & weld hardness testing	1,260	1,410	1,890	1,890	1,260	7710
Pipeline repair equipment	-	150	-	-	-	150
Total	**1,610**	**2,010**	**2,052**	**2,051**	**1,821**	**9,544**

Table 0.10 provides a breakdown of forecast opex for Option 2

Table 0.10: Forecast Opex - Option 2 $'000 January 2025

Title	2026/27	2027/28	2028/29	2029/30	2030/31	Total
TP compatibility assessment	31.7	-	-	-	-	31.7
Hazardous areas extents	52	52	-	-	-	104
Document updates	30	30	27	-	-	87
Further assessment or investigation required	136	136	136	136	-	544
Total	**2,450**	**218**	**163**	**136**	**-**	**767**

1.5.2.2 Risk assessment

Under Option 2, all sections of the network will be made compatible, therefore the likelihood of the identified loss of supply and compliance risk-events (e.g. Safety Case breach) occurring reduces to rare. This results in an overall risk assessment of low.

Table 0.11: Risk assessment – Option 2

Option 2	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Rare	Rare	Rare	Rare	Rare	Rare	Rare	Low
Consequence	Significant	Minimal	Major	Minor	Major	Significant	Major	
Risk Level	Negligible	Negligible	Low	Negligible	Low	Negligible	Low	

1.5.2.3 Alignment with vision objectives

Table 0.12 shows how Option 2 aligns with our vision objectives.

Table 0.12: Alignment with vision – Option 2

Vision objective	Alignment
Customer Focussed - Public Safety	Y
Customer Focussed – Customer Experience	-
Customer Focussed – Cost Efficient	N
A Leading Employer – Health and Safety	-
A Leading Employer – Employee Experience	-

Vision objective	**Alignment**
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	-
Operational Excellence – Benchmark Performance	-
Operational Excellence – Reliability	Y
Sustainable Communities – Enabling Net Zero	Y
Sustainable Communities – Environmentally Focussed	Y
Sustainable Communities – Socially Responsible	Y

All measures are the same as Option 1 for *Operational Excellence* and *Sustainable Communities*. However, Option 2 may be less cost efficient than Option 1, therefore could be less *Customer Focussed*.

Although Option 2 would see an uplift in public safety as the entire network would be ready for hydrogen, the incremental cost of upgrading the network in areas that are less certain to have hydrogen blends is not seen as prudent investment at this time.

1.5.3 Option 3 – No proactive network adaptation

Under Option 3 there would be no proactive network adaptation. We would then be in a position where we either choose to introduce hydrogen blends without having replaced potentially incompatible parts, or we deny renewable gas proponents access to our network until the adaptation has been done.

1.5.3.0 Advantages and disadvantages

Not adapting the gas network for hydrogen blends may offer short-term capital cost savings and operational simplicity, but it poses significant long-term disadvantages.

In theory, the majority of AGN's gas network and associated assets are capable of distributing hydrogen blends of up to 20%, with only a relatively small number of elastomers and metals that are susceptible to failure. It is therefore reasonable to consider the possibility of introducing such blends without proactive replacement, instead, waiting for assets to reach end of life before replacing them with compatible components. As and when network risks emerge, they would be managed reactively.

However, the potential consequences of a network failure, particularly at a high pressure regulating site, are severe. Loss of supply to >10,000 customers, and safety incidents are feasible events if elastomers and metals fail suddenly. The likelihood of these assets failing increases significantly if hydrogen blends are introduced into the network without proper precautions.

The lack of practical experience and application of hydrogen blending in an ageing gas distribution network means there are many unknowns surrounding the chemical and technical impact of hydrogen on our existing assets. Once hydrogen impacts on one type of asset and results in operational failures, it is likely that further failures will occur on all similar assets in a short period of time. This may result in significantly escalating reactive responses to incidents and loss of supply events.

Given these risks, if we were to pursue Option 3, we would likely not allow hydrogen to be introduced into our network until the necessary adaptation has been done. This brings forth a different set of major risks, relating to reputational damage and financial impact.

Public perception and investment confidence may decline due to perceived inaction, with AGN being seen as a barrier to decarbonization. Customers who cannot electrify would continue to rely on non-renewable gas, inhibiting the South Australian governments transition to net zero. Furthermore, by delaying network adaptation, work will be undertaken over a compressed timeframe, delivery costs would likely be more expensive due to labour scarcity and a cost premium to expedite procurement of materials.

1.5.3.1 Cost assessment

There are no upfront capital costs associated with this option. The network could be injected with hydrogen up to a 20% blend, without any proactive asset replacement being conducted.

Work to research the safe transition to renewable gas would continue, resulting in opex costs of around $0.25 million.

We highlight that in the event of asset failure, the cost of emergency works and call outs would be high, with reactive works typically costing 3-5 times more than proactive works. There would also be significant financial penalties associated with loss of supply incidents and regulatory non-compliances.

1.5.3.2 Risk assessment

Under Option 3, while we would likely mitigate the risk of operational failure by disallowing hydrogen injection until the network is ready, it would give rise to a moderate compliance and financial risks, as well as a high reputational risk. While the overall risk position would be an improvement on the untreated risk (i.e. doing nothing and allowing hydrogen into our network), Option 3 would not reflect the action of a prudent asset manager and would not reduce the risk to ALARP.

Table 0.13: Risk assessment – Option 3

Option 3	Health & Safety	Environment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Rare	Rare	Rare	Rare	Unlikely	Unlikely	Unlikely	High
Consequence	Significant	Minimal	Major	Minor	Significant	Major	Significant	
Risk Level	Negligible	Negligible	Low	Negligible	Moderate	High	Moderate	

1.5.3.3 Alignment with vision objectives

Table 0.14 shows how Option 3 aligns with our vision objectives.

Table 0.14: Alignment with vision – Option 3

Vision objective	Alignment
Customer Focussed - Public Safety	Y
Customer Focussed – Customer Experience	N
Customer Focussed – Cost Efficient	N
A Leading Employer – Health and Safety	-
A Leading Employer – Employee Experience	-
A Leading Employer – Skills Development	-
Operational Excellence – Profitable Growth	-
Operational Excellence – Benchmark Performance	-

Operational Excellence – Reliability	Y
Sustainable Communities – Enabling Net Zero	N
Sustainable Communities – Environmentally Focussed	N
Sustainable Communities – Socially Responsible	N

Failing to adapt the gas network for hydrogen compromises long-term affordability. While we could mitigate the safety and operational risk by postponing hydrogen injection, reactive adaptation is unlikely to be a cost-efficient solution as it could also result in prolonged delays for renewable gas proponents seeking connection (injection points), compromising customer outcomes.

Option 3 also fails to achieve any of our Sustainable Communities objectives. Not transitioning to hydrogen hinders progress toward net zero goals. The gas network would become a barrier rather than a bridge to sustainability and public confidence in the network's ability to meet future needs would deteriorate.

1.6 Summary of options assessment

Table 0.157 presents a summary of how each option compares in terms of the estimated cost, the residual risk rating, and alignment with our vision objectives.

Table 0.15: Comparison of options

Option	Estimated cost ($ million)	Treated residual risk rating	Alignment with vision objectives
Option 1	6.3	Low	Aligns with customer focused, a leading employer, operational excellence and sustainable communities.
Option 2	10.3	Low	Aligns with a leading employer, operational excellence and sustainable communities. Does not align with customer focused.
Option 3	0.25	High	Does not align

1.6.1 Recommended option

Option 1 is the recommended option. This solution involves the adaptation of strategically targeted areas of the network, whilst simultaneously undertaking necessary works for future renewable gas blending.

1.7 National Gas Law

Under the NGL, AGN is required to ensure its approach to managing the integrity of mains and services is efficient. The NGL also requires that AGN provides services in a safe and effective manner. The National Gas Objective (NGO) under the NGL provides:

The National Gas Objective as stated in the National Gas Law (NGL) is:

"to promote efficient investment in, and efficient operation and use of, covered gas services for the long term interests of consumers of covered gas with respect to:

> *a. price, quality, safety, reliability and security of supply of covered gas; and*
>
> *b. the achievement of targets set by a participating jurisdiction—*
>
> > *i. for reducing Australia's greenhouse gas emissions; or*
> >
> > *ii. that are likely to contribute to reducing Australia's greenhouse gas emissions."*

The focus of the NGO is on the long-term interests of consumers with respect to price, quality, safety, reliability, security of supply and the achievement of South Australia's decarbonisation targets. This renewable gas adaptation plan supports achievement of this outcome by ensuring the system can mitigate safety and supply risks effectively as it identifies, assesses, prioritises and mitigates these risks in the most efficient way.

Section 28 of the NGL outlines the role of the AER in ensuring proposals and outcomes of gas distribution businesses will or are likely to contribute to the achievement of the NGO. The AER must take into account the revenue and pricing principles under section 28(2) of the NGL when exercising a discretion in approving or making those parts of an access arrangement relating to a reference tariff.

This provides the ability for a gas distribution business to recover the cost of efficient and effective risk management practices so as to not put at risk the implementation of effective risk management practices.

In the context of this Plan, the most relevant revenue and pricing principle is section 24(2) of the NGL, which provides:

"A service provider should be provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs in—

> *(a) providing reference services; and*
>
> *(b) complying with a regulatory obligation or requirement or making a regulatory payment."*

Section 6 of the NGL also includes a "pipeline safety duty", which is defined in section 2 of the NGL as:

> *"pipeline safety duty means a duty or requirement under an Act of a participating jurisdiction, or any instrument made or issued under or for the purposes of that Act, relating to—*
>
> *(a) the safe haulage of natural gas in that jurisdiction; or*
>
> *(b) the safe operation of a pipeline in that jurisdiction;"*

As outlined, there are several pipeline safety duties arising from the Gas Act 1997 and the Work Health and Safety Act 2012 requiring us to implement risk mitigation activities such as mains replacement.

1.8 National Gas Rules

The NGR impose requirements on a gas distribution business to ensure its asset management strategies and plans are prudent and efficient. In order to recover the efficient cost of providing services, the NGR provides for the AER to assess whether the expenditure required complies with the capital and operating expenditure criteria. Those criteria require capital expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services (NGR 79(a)).

In addition, capital expenditure must also be justified under NGR 79(2) as follows:

> *(a) the overall economic value of the expenditure is positive; or*
>
> *(b) the present value of the expected incremental revenue to be generated as a result of the expenditure exceeds the present value of the capital expenditure; or*
>
> *(c) the capital expenditure is necessary:*
>
> *(i) to maintain and improve the safety of services; or*
>
> *(ii) to maintain the integrity of services; or*
>
> *(iii) to comply with a regulatory obligation or requirement; or*
>
> *(iv) to maintain the service provider's capacity to meet levels of demand for services existing at the time the capital expenditure is incurred (as distinct from projected demand that is dependent on an expansion of pipeline capacity); or*
>
> *(v) to contribute to meeting emissions reduction targets through the supply of services; or*
>
> *(d) the capital expenditure is an aggregate amount divisible into 2 parts, one referable to incremental services and the other referable to a purpose referred to in paragraph (c), and the former is justifiable under paragraph (b) and the latter under paragraph (c)."*

AGN's approach to managing integrity with the introduction of renewable gas and hydgrogen blends includes an assessment of options available to manage risk and test that the most efficient option is chosen and delivered at least cost. The framework of ISO 31000 is used to guide this process.

1.8.1 Consistency with the National Gas Rules

In developing these forecasts, we have had regard to Rule 79, Rule 74 and Rule 91 of the NGR. With regard to all projects, and as a prudent asset manager, we give careful consideration to whether capex is conforming from a number of perspectives before committing to capital investment.

1.8.1.0 NGR 79(1)

The proposed solution is prudent, efficient, consistent with accepted good industry practice and will achieve the lowest sustainable cost of delivering pipeline services:

- **Prudent** – The expenditure is necessary in order to ensure that the ongoing integrity of the network is maintained with the introduction of hydrogen and to reduce the risk of major gas escapes that could impact public safety and reliability of supply.

  Adapting our network in a way that mitigates foreseeable risks is consistent with our Safety Case and accepted industry practice. Hydrogen transportation is not new and the steps we are taking are known to address the risk associated with hydrogen in pipes. Several practicable options have been considered to address the risk. The proposed expenditure is therefore consistent with that which would be incurred by a prudent service provider.
- **Efficient** – The forecast expenditure is based on rates applied in similar projects and a detailed scope of work verified by an experienced third-party engineering consultant. Undertaking this project with a staged approach, focusing those parts of the network

that will receive hydrogen first (rather than embarking on network-wide asset replacement), will help us inform the scope and cost of the forward works program as blends of hydrogen increase over time, while lessening revenue impact on customers in the next period.

- **Consistent with accepted and good industry practice** – We are constantly reviewing the network risks in line with the Safety Case and are taking steps to mitigate likely issues that will result from the introduction of hydrogen. Renewable gas and associated technologies are being pursued by stakeholders, and are part of the decarbonisation agenda being developed by the Australian Commonwealth and State Governments. It is therefore good practice to ensure our network is ready to support this.
- **To achieve the lowest sustainable cost of delivering pipeline services** – The proposed expenditure is necessary to facilitate the early stages of hydrogen introduction into the network. Failure to do so would result in additional expenditure being incurred to reactively augment the network over a short, unmanageable timeframe.

  The project is therefore consistent with the objective of achieving the lowest sustainable cost of delivering services. The project will also enable us to inform and manage the future requirements of increasing hydrogen blends more efficiently. Fully understanding the effect of hydrogen blends on our assets, and taking a proactive approach, will allow us to operate the assets for as long as is safe and practicable, achieving the lowest sustainable cost of providing pipeline services.

NGR 79(2)

The proposed capex is justifiable under NGR 79(2)(c)(i) and (ii) as it is necessary to maintain the safety and integrity of services. Introduction of hydrogen into the distribution system without upgrading incompatible parts will likely resulting in asset failure, with the potential for significant safety and/or supply events.

The proposed capex is also justifiable under NGR 79(2)(c)(v). By investing in network adaptation in a targeted and timely manner to facilitate the distribution and use of renewable gas in the network, we are contributing to meeting emissions reduction targets through the supply of services.

NGR 74

The forecast costs have been arrived at on a reasonable basis by following realistic assumptions of costs, informed by independent engineering advice and experience in other jurisdictions. Rates are comparable with the market and the scope of the project is limited to only what is critical for the next access arrangement period, with a view to informing more accurate forecasts in future periods. We therefore consider the costs estimates represent the best forecast possible in the circumstances.

NGR 91

The proposed operating expenditure is required to undertake the necessary renewable gas research and studies to ensure the transition to renewable gas can occur in a safe and affordable manner. These are consistent with costs that would be incurred by a prudent service provider acting efficiently to achieve the lowest sustainable cost of service.

Appendix A Program breakdown

This section provides a breakdown of our proactive, staggered approach to network adaptation, which we believe is the most efficient transition path to renewable gas transportation.

1.8.1.0.1.A.1Hazardous area equipment

Compared to natural gas, renewable gas will likely include hydrogen blends, and over a certain concentration of hydrogen by volume we require a larger minimum hazardous area size in open spaces.

However, over the next five years we do not foresee a full conversion to, for example, hydrogen being completed. Therefore, a more conservative target of conversion to 20% hydrogen mixtures has been undertaken. For hazardous area equipment no work currently needs to be done for these levels of concentration. *'AGN technote - Group designation for Hazardous area electrical equipment in Hydrogen blends'* provides further detail into the reasons behind this.

Renewable gases with a hydrogen content greater than 20% will require a change to the equipment group, due to the reduced ignition energy compared to natural gas. This solution involves replacing Cat. IIA & IIB rated equipment with Cat. IIC, hydrogen ready equipment.

1.8.1.0.1.A.2Replace incompatible parts

Renewable gas that contains hydrogen can cause embrittlement of some metals at higher pressures, leading to a reduction in tolerance to crack-like defects and an acceleration of fatigue failure. We have identified that components with parts made from copper alloys, most aluminium alloys, and stable austenitic stainless steels are suitable for 10%, 20% and 100% service. Other metals with poor performance such as cast irons, high strength carbon steels (e.g. chrome-moly), martensitic stainless steels and nickel alloys also may not be compatible with renewable gases that contain hydrogen.

Working with the manufacturers to eliminate as many components as possible, AGN has identified that there are only 129 incompatible parts within its network that require remediation to allow for the safe introduction of a hydrogen blend, detailed in the table below.

Under the preferred option, we will replace 66 incompatible parts over the next 5 years.

Table 0.1: Identified hydrogen incompatible parts

Make/Model	Total Units	Units to replace 2025-2030
Axial flow valve	27	0
Mooney flow grid regulators	102	66
Total	**129**	**66**

1.8.1.0.1.A.3Weld procedures and weld hardness testing

A compatibility review found that most of AGIG's pipelines (>1,050kPa) with design factors below .04 and Network steel piping (<1,050kPa) can safely be used to transport renewable gas with hydrogen blends, as well as pure hydrogen. However, existing weld procedures will not be appropriate and must re-qualified.

We must develop weld procedures for 29 out of the 41 steel pipelines identified in Table 1-5 below, to ensure the safe operation of our steel pipelines. We must also undertake hardness testing for a random sample of welds in each pipeline, to show compliance with the hardness limits of ASME B31.12.

The weld hardness testing project is balanced across the next ten years. The project is delivered relatively evenly across the period to allow resources to be optimised with a steady workflow.

Table 0.2: Steel pipelines requiring new weld procedures and weld hardness testing

Pipeline/Section Name	License Number	2025-2030	2030-2035
M5 Prospect to Brompton	5	☑	-
M6 Churchill Road	6	☑	-
M7 Churchill Road to Dry Creek	7	☑	-
M12 Waterloo Cnr to Yatala Vale	12	☑	-
M21 Grid System to Lonsdale	21	-	☑
M22 Le Fevre Peninsula	22	☑	-
M36 Seacombe Gardens to Flagstaff Hill	36	☑	-
M37 Plympton to Edwardstown	37	☑	-
M38 GMH Elizabeth	38	☑	-
M42 Brompton to Port Stanvac	42	☑	-
M53 Lonsdale to Noarlunga	53	-	☑
M55 Elizabeth	55	☑	-
M60 Richmond to STA	60	-	☑
M63 Port Pirie	63	-	☑
M68 Nuriootpa	68	-	☑
M71 Birkenhead	71	☑	-
M76 Flagstaff Hill - Blacks Road	76	-	☑
M79 Glanville to Port Adelaide	79	☑	-
M80 Port Adelaide to Dry Creek	80	☑	-
M82 Elizabeth to Smithfield Plains, Coventry Road	82	☑	-
M83 Port Adelaide to Queenstown	83	☑	-
M84 Para Hills to Ingle Farm	84	-	☑
M90 Hendon to South Brighton	90	☑	-

Pipeline/Section Name	License Number	2025-2030	2030-2035
M94 Dry Creek to Ingle Farm	94	☑	-
M101 Eatern Ring Main	101	☑	-
M114 Southern Loop	114	☑	-
M117 Brompton to ACI	117	-	☑
M120 Graves Street, Newton	120	☑	-
M124 Cormack Road to Cooper's Brewery	124	-	☑
M126 Seagas Interconnection	126	☑	-
M131 Port Noarlunga to Noarlunga Downs	131	☑	-
M143 Greenhill Road	143	☑	-
M148 West Terrace	148	☑	-
M149 Seacombe Gardens	149	☑	-
M150 Tanunda	150	-	☑
M169 Seaford	169	☑	-
Berri Township	Berri	-	☑
Murray Bridge Township	MB	-	☑
Snuggery	Snuggery	-	☑
M172 Park Terrace	172	☑	-
M183 Hindmarsh	183	☑	-
M184 Murray Bridge Township #2	184	-	☑

1.8.1.0.1.A.4Pipeline repair equipment

Further work is required to assess compatibility of transmission pipeline repairs undertaken with Plidco & Smith Clamps and the purchase of compatible equipment. This project will be delivered during the first year of the FY2026-31 AA period, as the information will assist in developing future asset management plans in relation to upgrades and/or replacement.

1.8.1.0.1.A.5Transmission pressure pipeline compatibility assessment

Most of the AGN SA transmission pressure pipelines have already been assessed for renewable gas and blends of hydrogen compatibility as part of the Australia Hydrogen Centre (AHC technical assessment). One pipeline in SA was excluded from the scope due it's complexity, however it still requires suitable assessment prior to the introduction of renewable gas with hydrogen blends. The pipeline is identified in the table below.

Table 0.3: Transmission pressure pipelines requiring hydrogen compatibility assessments

Pipeline name / section name	Pipeline License	Identified for AA period

SPL 11 Riverland Pipeline	11	0

This project will be delivered in the first year of the next AA period, as the information will assist in developing forward looking upgrades or replacement asset management plans.

1.8.1.0.1.A.6Hazardous areas extents

We must conduct a technical review of 260 Pressure Reduction Sites (PRS). This work will require a qualified engineer to review each PRS site and provide recommendations to the business to safeguard assets and ensure compliance by upgrade or relocation in future. This activity is forecast to start in 2026-27 as the information will assist in developing forward looking asset management plans.

We have deemed this the most prudent approach rather than forecast an allowance for the relocation or upgrade works to commence immediately following the technical review. However, if during the next five years there are immediate safety concerns regarding hazardous areas and the volumetric increases in renewable gas within the network we will reallocate resources accordingly.

1.8.1.0.1.A.7Document updates

We must ensure documentation complies with the introduction and operation of a renewable gas that includes hydrogen blends. For AGN SA, the following types of documentation have been identified:

Pipeline associated documentation, for example procedure 9066, pipeline defect assessment;

An updated SMS for each affected pipeline;

- Updated procedures - AGN LMP for 100% H2 in alignment with the HyP Adelaide hydrogen pipeline
- Updates to the Geospatial Information System to indicate renewable gas with blended hydrogen areas

The project shall be completed to allow safe operations from 2028 onwards, when hydrogen will be actively used within the AGN network.

1.8.1.0.1.A.8Further assessment or investigation required

Further assessments are required to ensure the safe and progressive introduction and operation of a renewable gas hydrogen blend into our networks. For example, we need to perform risk assessments on possible loss of isolation for all components containing nickel alloys, any untested aluminium alloy or elastomers. This activity is phased to align with the 'replace incompatible parts' project to optimise the available workforce. The project is to be delivered in 2026-27 to allow time to develop asset management strategies in line with volumetric increase of renewable gas in the network.

Appendix B Comparison of risk assessments

Untreated	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Significant	Minimal	Major	Minor	Major	Major	Significant	
Risk Level	Moderate	Negligible	High	Low	High	High	Moderate	

Option 1	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Rare	Rare	Rare	Rare	Rare	Rare	Rare	Low
Consequence	Significant	Minor	Major	Significant	Major	Significant	Major	
Risk Level	Negligible	Negligible	Low	Negligible	Low	Negligible	Low	

Option 2	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Rare	Rare	Rare	Rare	Rare	Rare	Rare	Low
Consequence	Significant	Minor	Major	Significant	Major	Significant	Major	
Risk Level	Negligible	Negligible	Low	Negligible	Low	Negligible	Low	

Option 3	Health & Safety	Environ-ment	Operations	People	Compliance	Rep & Customer	Finance	Risk
Likelihood	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	High
Consequence	Significant	Minor	Major	Significant	Major	Significant	Major	
Risk Level	Moderate	Low	High	Moderate	High	High	High	

Appendix C Capex estimates

Below is a breakdown of some of the key capex components

Table 0.1: Cost breakdown for replacement of incompatible parts

Make/Model	Volume AGN SA	Estimated replacement cost each	Estimated Labour cost each	Total – initial	Total AGN SA - Final
Axial flow Valve	27	$15,000	$9,600	$664,200	$0
Bray S31 valves	N/A	-	-	-	-
Brook B600E valves	N/A	-	-	-	-
Keystone AR2 butterfly valves	N/A	-	-	-	-
Crosby 951 relief valve/regulator	N/A	-	-	-	-
Mooney Flowgrid regulators	102	$5,200	$4,800	$1,020,000	$660,000
Pietro Fiorentini Reval 182, Reflux 819	N/A	-	-	-	- -
Fisher 951 partial relief valve	N/A	-	-	-	-
Keystone F2 Butterfly Valve	N/A	-	-	-	-
John FIG 600 Flanged Gate Valve	N/A	-	-	-	-
Swagelok SS-8GUF8	N/A	-	-	-	-
Total					**$660,000**

Table 0.2: Cost breakdown for weld procedures

Cost per weld	# weld procedures required	Forecast Total cost
$30,000	5	$150,000

Table 0.3: Weld procedure costs per pipeline

Pipeline number	Pipeline/Section Name	Number of weld procedures required	Cost – initial	Cost - final round
M5	Prospect to Brompton	3	$90,000	$90,000
M6	Churchill Road	3	$90,000	$90,000
M7	Churchill Road to Dry Creek	3	$90,000	$90,000
M12	Waterloo Cnr to Yatala Vale	3	$90,000	$90,000
M21	Grid System to Lonsdale	3	$90,000	-
M22	Le Fevre Peninsula	3	$90,000	$90,000
M36	Seacombe Gardens to Flagstaff Hill	3	$90,000	$90,000
M37	Plympton to Edwardstown	3	$90,000	$90,000
M38	GMH Elizabeth	3	$90,000	$90,000
M42	Brompton to Port Stanvac	3	$90,000	$90,000

M53	Lonsdale to Noarlunga	3	$90,000	-
M55	Elizabeth	3	$90,000	$90,000
M60	Richmond to STA	3	$90,000	-
M63	Port Pirie	3	$90,000	-
M68	Nuriootpa	3	$90,000	-
M71	Birkenhead	3	$90,000	$90,000
M76	Flagstaff Hill - Blacks Road	3	$90,000	-
M79	Glanville to Port Adelaide	3	$90,000	$90,000
M80	Port Adelaide to Dry Creek	3	$90,000	$90,000
M82	Elizabeth to Smithfield Plains, Coventry Road	3	$90,000	$90,000
M83	Port Adelaide to Queenstown	3	$90,000	$90,000
M90	Hendon to South Brighton	3	$90,000	$90,000
M94	Dry Creek to Ingle Farm	3	$90,000	$90,000
M101	Eatern Ring Main	3	$90,000	$90,000
M114	Southern Loop	3	$90,000	$90,000
M117	Brompton to ACI	3	$90,000	-
M120	Graves Street, Newton	3	$90,000	$90,000
M124	Cormack Road to Cooper's Brewery	3	$90,000	-
M126	Seagas Interconnection	3	$90,000	$90,000
M131	Port Noarlunga to Noarlunga Downs	3	$90,000	$90,000
M143	Greenhill Road	3	$90,000	$90,000
M148	West Terrace	3	$90,000	$90,000
M149	Seacombe Gardens	3	$90,000	$90,000
M150	Tanunda	3	$90,000	-
M169	Seaford	3	$90,000	$90,000
Berri	Berri Township	3	$90,000	-
MB	Murray Bridge Township	3	$90,000	-
Snuggery	Snuggery Pipeline	3	$90,000	-
M172	Park Terrace	3	$90,000	$90,000
M183	Hindmarsh	3	$90,000	$90,000
M184	Murray Bridge Township #2	3	$90,000	-
		Total	$3,780,000	**$2,610,000**

Table 0.4: Cost for pipeline repair equipment

TP temp repair- Plidco and smithclamp	Number required	Forecast Total
$10,000	15	**$150,000**

Table 0.5: Cost breakdown for weld hardness testing

Cost per weld inspection (assume similar to coating repair)

$30,000

Pipeline number	Pipeline/Section Name	Licence Number	Pipeline	Length	Number of	Cost	Year 1	Year 2	Year 3	Year 4	Year 5	Cost 3rd	
M5	Prospect to Brompton	M5	SA		3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000	$90,000	Y
M6	Churchill Road	M6	SA		3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000	$90,000	Y
M7	Churchill Road to Dry Creek	M7	SA		3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000	$90,000	Y
M12	Waterloo Cnr to Yatala Vale	M12	SA		3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000	$90,000	Y
M21	Grid System to Lonsdale	M21	SA		3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000		
M22	Le Fevre Peninsula	M22	SA		3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000	$90,000	Y
M36	Seacombe Gardens to Flagstaff Hill	M36	SA		3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000	$90,000	Y
M37	Plympton to Edwardstown	M37	SA		3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000	$90,000	Y
M38	GMH Elizabeth	M38	SA		3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000	$90,000	Y
M42	Brompton to Port Stanvac	M42	SA		3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000	$90,000	Y
M53	Lonsdale to Noarlunga	M53	SA		3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000		
M55	Elizabeth	M55	SA		3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000	$90,000	Y
M60	Richmond to STA	M60	SA		3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000		

M63	Port Pirie	M63	SA	3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000		
M68	Nuriootpa	M68	SA	3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000		
M71	Birkenhead	M71	SA	3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000	$90,000	Y
M76	Flagstaff Hill - Blacks Road	M76	SA	3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000		
M79	Glanville to Port Adelaide	M79	SA	3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000	$90,000	Y
M80	Port Adelaide to Dry Creek	M80	SA	3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000	$90,000	Y
M82	Elizabeth to Smithfield Plains, Coventry Road	M82	SA	3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000	$90,000	Y
M83	Port Adelaide to Queenstown	M83	SA	3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000	$90,000	Y
M84	Para Hills to Ingle Farm	M84	SA	3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000		
M90	Hendon to South Brighton	M90	SA	3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000	$90,000	Y
M94	Dry Creek to Ingle Farm	M94	SA	3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000	$90,000	Y
M101	Eatern Ring Main	M101	SA	3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000	$90,000	Y
M114	Southern Loop	M114	SA	3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000	$90,000	Y
M117	Brompton to ACI	M117	SA	3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000		
M120	Graves Street, Newton	M120	SA	3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000	$90,000	Y
M124	Cormack Road to Cooper's Brewery	M124	SA	3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000		

M126	Seagas Interconnection	M126	SA	3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000	$90,000	Y
M131	Port Noarlunga to Noarlunga Downs	M131	SA	3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000	$90,000	Y
M143	Greenhill Road	M143	SA	3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000	$90,000	Y
M148	West Terrace	M148	SA	3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000	$90,000	Y
M149	Seacombe Gardens	M149	SA	3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000	$90,000	Y
M150	Tanunda	M150	SA	3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000		
M169	Seaford	M169	SA	3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000	$90,000	Y
Berri	Berri Township	Berri	SA	3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000		
MB	Murray Bridge Township	MB	SA	3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000		
Snuggery		Snuggery	SA	3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000		
M172	Park Terrace	M172	SA	3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000	$90,000	Y
M183	Hindmarsh	M183	SA	3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000	$90,000	Y
M184	Murray Bridge Township #2	M184	SA	3	$90,000	$18,000	$18,000	$18,000	$18,000	$18,000		
				Totals	**$3,780,000**	**$756,000**	**$756,000**	**$756,000**	**$756,000**	**$756,000**	**$2,520,000**	
	Total										**$2,520,000**	

Appendix D Opex estimates

Below is a breakdown of some of the key opex components

Table 0.1: Cost breakdown for TP compatibility assessment

Network	Pipeline License	Pipeline Name	Forecast cost
AGN SA	SPL11	Riverland Pipeline	**$31,709**

*TP Compatibility Assessment - pipelines excluded from GPA - 210620-REP-001 - Piping Compatibility

Table 0.2: Cost Breakdown for hazardous area extents

Hazardous area extents review - PRS	Cost per hour - engineer	Number hours to review	Forecast cost
260	$200	15	**$150,000**

Table 0.3: Cost breakdown for assessments and investigations

Scope	Indicative cost	Total
Perform risk assessments on possible loss of isolation for all components containing nickel alloys, any untested aluminium alloy or selastomers that are listed as "C: Confirm" in the Material Compatibility table (Table 3)	15 people by 8 hours for workshop @ $200ph	**$24,000**

Table 0.4: Cost breakdown for document updates

Scope	Indicative cost	Cost
Update pipeline documentation e.g. Procedure 9066, pipeline defect assessment	Workshop - 10 people by 8 hours for workshop @ $200ph	$16,000
SMS for all pipelines	Workshop - 30 people by 8 hours for workshop @ $200ph	$48,000
Update procedures - AGN LMP for 100% H2 - to cover new HyP MV Hydrogen Pipeline	Workshop - 10 people by 4 hours for workshop @ $200ph	$8,000
GIS - indicate blended H2 areas	Time allocation of hydraulic engineers	$15,000
Total		**$87,000**