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RBP Access Arrangement Business Cases

Roma to Brisbane Gas Pipeline Access Arrangement 2028–32

29 June 2026

Pipeline Integrity Business Case

Roma to Brisbane Gas Pipeline Access Arrangement 2028–32

18 June 2026

Contents

Overview

Number/ identifier	A-1_Pipeline Integrity
Description of Issue/ Project	The RBP includes over 800km of buried pipelines, in sizes between DN200 and DN400, the oldest of which was constructed in 1968-1969 and has been in service ever since. All buried pipelines are subject to coating deterioration and corrosion from the soil environment and require integrity management to comply with standards and legislation. The RBP has particular characteristics such as is over-the-ditch tape coating system and its age that mean it requires significantly greater effort and expense in corrosion and integrity management than most other pipelines in Australia. If insufficiently managed the corrosion and integrity issues could lead to pipeline failures affecting both public safety (given the pipeline traverses many populated areas) and security of supply to customers. The successful solution will ensure an effective pipeline integrity management system is continued and that the risk of pipeline failure is managed to an acceptable level considering health and safety and security of supply.
Options considered	The following options have been considered: 1. Option 1: Do Nothing (Carry out only basic pipeline integrity activity; allow pipelines to deteriorate) **2. Option 2: Carry out pipeline integrity management activities** 3. Option 3: Replace pipelines
Proposed Solution	The scope of Option 2: Carry out pipeline integrity management activities comprises a number of different aspects: • Inline Inspection (ILI) • Excavation, integrity works and new coating upgrades and repair • Cathodic Protection Replacement and Upgrades • Other associated equipment upgrades to support the above activities
Estimated Cost	$39.3 million
Relevant standards	• AS 2885.3 Pipelines: Gas and Liquid Petroleum Operations and Maintenance. • AS 2832.1 Metal Pipeline Protection • AS 4853 2012 Electrical Hazards on Metallic Pipelines • RBP Pipeline Licence
Stakeholder Engagement	• Scope discussed during RBP Access Arrangement Stakeholder Meetings #3 (25/11/2025); #4 (10/02/2026); and #5 (31/03/2026)
Consistency with National Gas Rules (NGR)	The pipeline integrity management work complies with the capital expenditure criteria in Section 79 of the NGR because it: • is necessary to maintain and improve the safety and integrity of services (79(2)(c)(i) and (ii)); and • 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 (79(1)(a)).

1. Program details

1.1. Background

The RBP system includes over 800 km of buried pipelines, in sizes between DN200 and DN400, the oldest of which was constructed in 1968-69 and has been in service ever since. The pipelines transport natural gas between Wallumbilla, near Roma, and the Brisbane metropolitan region in south-east Queensland. The RBP is the sole supply route for natural gas to homes and businesses in south-east Queensland, including Dalby, Oakey, Toowoomba, Ipswich, greater Brisbane, the Gold Coast and far northern New South Wales.

All buried pipelines constructed of steel pipe are subject to coating deterioration and corrosion from the soil environment and require integrity management to comply with standards and legislation. Part of this integrity management is protection from corrosion that is applied to the pipeline. Primarily this protection comes in two ways. The first is a coating protection that is applied to the pipeline at the time of construction. The second is cathodic protection (CP) which uses current and an anode to protect the pipeline. As pipelines age the level of effort required to maintain their integrity increases.

The to the technologies available at the time of construction for the original RBP has particular characteristics, such as its over-the-ditch-applied polyethylene tape coating system (on the original DN250, DN300 and DN200 pipelines). Along with the age of the original pipelines means it requires significantly greater effort and expense in corrosion and integrity management than most other pipelines in Australia. This includes risks associated with deterioration of the tape coating, corrosion of the pipe wall and other mechanisms such as stress corrosion cracking.

1.2. DN250 and DN300 and DN200 Pipelines (1969 Vintage)

Globally in the pipeline industry there is an accepted differentiation between 'modern' and 'vintage' pipelines. The 'vintage' category generally includes pipelines constructed prior to the mid-1970s, which have relatively low toughness steel, over-the-ditch-applied coatings and a lower level of inspection and quality assurance compared to modern pipelines. The original 1960s RBP segments are clearly considered 'vintage' pipelines.

If insufficiently managed the corrosion and integrity issues could lead to pipeline failures affecting both

- public safety, given significant portions of the RBP are located within residential areas in Brisbane and surrounding areas, and
- security of supply to customers.

There have been significant improvements in pipeline coating technology such that modern pipe coatings such as fusion-bonded epoxy can be expected to last 50-60 years or longer, compared to less than 30-40 years seen on some sections of the RBP with the original over-the-ditch polyethylene tape coating system. One aspect of this is the thorough abrasive blast cleaning of the steel surface prior to coating, which was not done in the 1960s construction.

No design life for the pipeline was specified at original construction in 1968-69. In 2008-2009 a design life review was conducted (at 40 years age) which concluded that the pipeline could continue to operate subject to appropriate integrity management. A number of specific actions were recommended in the design life review including an increased focus on coating refurbishment. In 2015 a Remaining Life Review (as per AS 2885.3-2012) was conducted for the Metro section and in 2016 for the DN250 section. Since this time a major repair and CP program has been undertaken where it has been evident that pipeline coating integrity continues to decline and the expenditure required to maintain safe operation continues to increase.

1.3. DN400 Pipeline System

The RBP DN400 first looping stages were constructed in 1988 and are approaching 30 years in service. This pipeline has a different risk profile from the DN250 and its factory extruded HDPE coating ("yellowjacket") has generally performed well. However, In APA's experience, pipelines from the 1980s such as the RBP DN400 also have some of the characteristics of 'vintage' pipelines. In recent years evidence of longitudinal splitting of heat shrink sleeves has been observed which have led to corrosion of the pipeline.

Design lives for the DN400 looping stages are likely to have been nominated as between 40 and 60 years in accordance with normal industry practice, at the time of design and construction of each looping stage. The next Remaining Life Review on the DN400 system will be completed in 2032 (10 years from its MOP Upgrade) in accordance with AS 2885.3-2012, or earlier if required based on ILI and engineering assessment.

1.4. Main Integrity Issues

The main integrity issues faced by the RBP include the following:

- Deterioration and disbondment of the external coatings leading to high load on CP system and external corrosion where the CP system cannot sustain complete protection of the pipe wall
- Shielding of CP by disbonded coating leading to inadequate protection of pipe wall in shielded areas, including the entire DN250 pipeline and field joints with heat shrink sleeves and tape wrap coating on the DN400
- Deterioration of dents and gouges by a combination of the above factors with increased risk of fatigue cracking or stress corrosion cracking (SCC)
- 1960s Electric Resistance Welded pipes seams (DN250 Brassall to Bellbird Park) with occasional lack of fusion or other defects in the seam welds, which although passed a hydrotest at commissioning, are at risk of growth through SCC or fatigue
- Bending strain on pipeline caused by ground movement or external loads leading to excessive longitudinal stresses, coating degradation and potential circumferential SCC

1.5. Assessment of options

A number of methods have been considered with regard to maintaining pipeline integrity for the RBP Asset. These include:

- Inline Inspection (ILI)
- Excavation, integrity works and new coating upgrades and repairs
- Cathodic Protection Replacement and Upgrades
- Other associated equipment upgrades to support the above activities

1.5.1. Inherent Risk assessment

The inherent business case risk is shown below, as well as the residual risk rating of the preferred options. The risk assessment is based on APA's Enterprise Risk Matrix – Projects.

For a worst-case scenario, we need to consider the potential ramifications of a failure of Pipeline Integrity if these activities are not undertaken.

With a pipeline partially unprotected from corrosion, it could be assumed that corrosion occurs at a coating defect and the pipe wall thins to the extent where it fails by leak or rupture. A linear length could rupture where there is severe damage to the coating, such as a mechanical gouge removing the coating, or a large crack developing due to degradation of the polyethylene coating or seasonal ground movement.

A rupture is dramatic, causing severe asset damage and the potential for fatalities if people are present. Depending on the location, the pipeline might be out of service for days, weeks or even months, and recommencement may be subject to successful hydro-testing or only offered at a lower operating pressure.

Table 2-1: Inherent risk rating of the Pipeline Integrity business case

Risk Area	Option 1		Option 2:	
	Likelihood / Impact	Inherent risk rating	Likelihood / Impact	Risk rating
Health & Safety	Remote / Catastrophic	High	Rare / Catastrophic	Moderate
Environment	Remote / Significant	Low	Rare / Significant	Negligible
Operational	Remote / Significant	Low	Rare / Significant	Negligible
People	Remote / Significant	Low	Rare / Significant	Negligible
Compliance	Remote / Significant	Low	Rare / Significant	Negligible
Reputation & Customer	Remote / Major	Moderate	Rare / Major	Low
Financial	Remote / Significant	Low	Rare / Significant	Negligible
Untreated risk		**High**		**Moderate**

The risk assessment indicates that there is the potential for High risk, resulting from the failure to maintain effective Integrity of the pipeline. The impact is largely based upon the outcomes from failing to maintain a safe pipeline system and the associated disruption to normal business.

The preferred options presented in sections 3 to 6 lower the inherent risk from High to a Moderate residual risk.

Financial assessment

A consideration of the pros and cons of the expected financial outlays for all options is shown below. Net Present Value calculations have not been undertaken as a realistic expenditure profile is unable to be ascertained for option 1. Given end-of-life replacement and rectification costs are inevitable, this business case demonstrates that the proposed expenditure is efficient and appropriate to manage the associated risks.

Table 2-2: Financial assessment of the Integrity business case for ILI, CP & associated integrity activities.

	Commentary
Option 1: Do Nothing (Carry out only basic pipeline integrity activity; allow pipelines to deteriorate)	• No proactive management of the CP for the pipeline will lead to pipeline corrosion. • Corrosion will reduce the capacity of the pipeline through gas leakage, potentially causing damage to the environment and people, as well as a loss of revenue. • To repair extensive levels of corrosion entails digging and replacing entire sections of pipeline. This is more expensive than maintaining on-going CP of the pipeline and will also require lengthy interruptions to gas supply. • Interruptions to customer supply and gas leakage reduces income as will any pipeline failure that leads to a fatality or injury, due to litigation costs and payments for damages.

	• Regulatory and licence breaches would lead to fines and potentially a loss of the pipeline licence. • These outcomes would severely impact share price and the longevity of the business. • Avoided capex cost in the earlier years will be more than offset by the potential financial and reputational cost of regulatory fines, penalties arising from reputational damage, legal action and the loss of the RBP operating licence. • If a scheduled ILI cannot be completed to meet the date specified in the PIMP, one of the options available to the operator is to set a restricted operating pressure.
Option 2: Carry out pipeline integrity management activities	• Conduct ILI and associated dig & repair in accordance with AS 2885 Pipeline Integrity Management, ensuring defects are identified, validated, and remediated before they threaten pipeline integrity. • Cathodic protection system replacements are identified from detailed CP survey data and field assessments. • Replacements and upgrades will improve the standardisation of field equipment, reduce obsolescence risk and the financial costs of carrying multiple spare parts. • Steady replacement rate over the coming years gives predictability in expenditure. • Strengthening leak detection capabilities, including enhanced methane survey activities and other monitoring technologies, to enable more accurate and quantified leak detectionor emissions and support rapid response before safety or environmental impacts occur. • Other associated equipment upgrades to support the above activities
Option 3: Replace Pipelines	• Cost prohibitive, not prudent

Based on the risk and financial assessments above, RBP's preferred option to appropriately balance costs and risks is Option 2 across all components of the CP business case.

1.6. Consistency with the National Gas Rules and other regulations

The RBP is a major national pipeline, and good practice requires it to be appropriately equipped to eliminate the risk of corrosion events. Licence conditions and Australian Standards require management to actively manage corrosion.

The planned capital expenditure on the RBP is designed to meet the capital expenditure objectives set out in in section 79(2)(c)(ii) of the National Gas Rules (NGR) as the work is necessary to maintain the integrity of service.

Consistent with Rule 79 of the National Gas Rules, APA considers that the capital expenditure is:

Prudent – The expenditure is necessary in order to maintain and improve the safety of services and maintain the integrity of services to customers and is of a nature that a prudent service provider would incur. The program aligns with Australian Standard (AS) 2832.1 Cathodic Protection of Metals: Pipes and Cables, AS 2885.3 Pipelines: Gas and Liquid Petroleum Operations and Maintenance; and AS3000: Electrical Installations;

Efficient – The works will be subject to APA's procurement policy. The field work will be carried out by the external contractors that has been used to date, who has demonstrated specific expertise in completing the installation of the facilities in a safe and cost-effective manner. The expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur; and

Consistent with accepted and good industry practice – Addressing the risks associated with the cathodic protection system failure and replacing assets that have reached the end of their useful life is accepted as good industry practice. In addition, the reduction of risk to as low as reasonably practicable while balancing cost is consistent with Australian Standard AS2885.Proposed costs for FY28-FY32

The total forecast capital expenditure for the Roma to Brisbane Pipeline (RBP) Integrity Program over the FY28–FY32 access arrangement period is **$39.3 million (Real $2026-27)**. This forecast represents the aggregated cost of the individual integrity activities described in Sections 3 to 8, including In Line Inspection, Validation Digs, Safety Critical Digs, Cathodic Protection, Pigging Enablement Upgrades, and Enhanced Methane Survey initiatives. The expenditure has been developed on a **prudent, efficient, and evidence based basis**, drawing on historical delivery volumes, asset condition data, and current market tested contractor rates under APA's national vendor arrangements. The timing and scale of the forecast reflect the requirements of the Pipeline Integrity Management Plan (PIMP), AS 2885.3, and licence obligations, ensuring that investment is targeted to known and foreseeable integrity risks. The proposed expenditure avoids inefficient deferral or reactive intervention and represents the **lowest sustainable cost** of maintaining the safety, reliability, and integrity of services, consistent with the capital expenditure criteria in **NGR Rule 79**.

Table 2-3: Total cost for Integrity business case ($000's Real 2026-27)

Category	FY28	FY29	FY30	FY31	FY32	Category Total
ILI	2,103	1,271	93	1,658	877	6,002
Validation dig	2,768	1,964	3,013	1,978	525	10,249
CP	2,653	2,657	2,666	2,676	2,683	13,335
Safety Digs	721	2,686	1,246	2,182	729	7,564
ILI upgrade	-	2,114	-	-	-	2,114
FY Total	8,244	10,693	7,017	8,495	4,815	39,265

2. In Line Inspection (ILI)

2.1. Project objective and scope

As with all significant hydrocarbon transmission pipelines, the RBP requires regular inspections. In-line inspection (ILI) using intelligent pigs is one of the most important and conclusive activities in the spectrum of pipeline integrity management processes, as it allows pipeline deterioration and damage to be identified and rectified prior to failure.

ILI results are used to reassess dig numbers taking corrosion growth rates and adverse tool tolerance into account, as required by Australian Standard AS 2885.3-2012. Corrosion growth modelling based on data from previous ILI and validation excavations has indicated the appropriate re-inspection interval for metal loss as per the table below.

APA's experience is that reinspection generally results in a decrease in the number of features requiring repair, as actual corrosion growth rates can be established for features rather than assuming a uniform and conservative growth rate.

The required ILI technologies are as follows:

- High-resolution magnetic flux leakage (MFL) inspection – detects corrosion, gouges, grooves, mill defects, girth weld anomalies and other metal loss features. This is the standard ILI for which the corrosion growth modelling determines reinspection intervals.
- Geometry or calliper inspection – detects dents, ovality (out of roundness) and similar – can indicate 3rd party mechanical damage, rock dents from flooding or landslides, or dents remaining in the pipeline since construction. This is generally done in conjunction with the MFL inspection. It is noted by APA that dents are high risk of cracking or gouging and are the most likely defects to lead to pipeline failure. The ILI detection of dents has been a key part of the RBP integrity program and has enabled APA to find and repair dents with gouges, corrosion and cracking that would have had significant consequences if left to fail.
- Inertial Mapping (IMU) – Maps the geographical position of the pipeline centreline and records any movement or change in shape since previous inspection. IMU pigging enables curvature and strain analysis which is a key factor in mitigation of circumferential stress corrosion cracking. This is also done in conjunction with the MFL inspection as required.
- Electro-Magnetic Acoustic Transducer (EMAT) inspection –detects cracking and crack-like features. EMAT is used in the RBP to detect and manage stress corrosion cracking and longitudinal weld anomalies. This is a more specialised inspection technique with tighter operational requirements on pipeline velocity and may be scheduled separately or together with standard MFL ILI. EMAT is of particular importance to the original build pipeline segments as they are the most susceptible to stress corrosion cracking.

The table below illustrates the ILIs completed in the current access arrangement period and planned for the remaining years of the current period and next access arrangement period.

Table 3-1: ILI Next due dates

Pipeline Name	Section Name	MFL Due	EMAT Due
RBP Lytton Ltl	SEA MLV - Lytton Station	2027-07	
RBP DN300 Metro	S1/A Bellbird Park - Mount Gravatt	2028-10	2026-12
Peat Ltl	S1 Scotia-Woodroyd	2029-07	
Peat Ltl	S2 Woodroyd - Arubial	2029-07	
RBP DN400	S6/F Oakey - Gatton (OAK-GAT)	2030-02	
RBP DN400	S7/G Gatton-Swanbank	2030-02	
RBP400 Metro	Loop1: Preston Rd - Paringa Rd	2030-05	

2.2. Background

APA has a national policy and schedule for ILI. The policy sets out the frequency and schedule for ILI across the company's pipelines. This policy sets the standard duration between ILI at 10 Years, unless an engineering assessment determines otherwise. Further, the RBP is designated in the Queensland Petroleum and Gas (Production and Safety) Act 2004 as a 'Strategic Pipeline'. Under this legislation, all sections of pipeline under the RBP licence (#2) are required to be inspected by ILI within the first 7 years of operation, and at least once within every 10-year period after that. However, for the RBP, due to its age and complexity of integrity threats, many sections require more frequent inspections.

2.3. Assessment of options

The options considered for the access arrangement period are:

— Option 1: Do nothing

— Option 2: Mandatory In Line inspection as per integrity management plan & AS2885

2.3.1. Risk assessment

Failing to conduct mandatory In Line Inspections can result in corrosion and cracking remaining undetected and contribute to a loss of containment.

Table 3–2: Risk assessment – ILI Inspections

Risk Area	Option 1		Option 2:	
	Likelihood / Impact	Inherent risk rating	Likelihood / Impact	Risk rating
Health & Safety	Remote / Catastrophic	High	Rare / Catastrophic	Moderate
Environment	Remote / Significant	Low	Rare / Significant	Negligible
Operational	Remote / Significant	Low	Rare / Significant	Negligible

People	Remote / Significant	Low	Rare / Significant	Negligible
Compliance	Remote / Significant	Low	Rare / Significant	Negligible
Reputation & Customer	Remote / Major	Moderate	Rare / Major	Low
Financial	Remote / Significant	Low	Rare / Significant	Negligible
Untreated risk		**High**		**Moderate**

Option 1

The 'Do Nothing' option carries a high risk that the condition of the pipeline will be unknown. This will result in any defects or anomalies remaining unidentified and subsequently not being treated.

Although this option defers any capital expenditure, it increases the risk of corrosion and the expenditure to rectify corrosion (once it occurs) will cost significantly more than conducting In line inspections (option 2) to ensure pipeline integrity.

If a scheduled ILI cannot be completed within the timeframe specified in the Pipeline Integrity Management Plan (PIMP), the operator may be required to apply a Restricted Operating Pressure (ROP) in accordance with AS 2885.3. Under this framework, the initial ROP is set to the P98 value of one year of pressure history (with at least 730 data points). From the second year onward, the ROP decreases annually by 2% where the design factor (DF) is less than or equal to 0.33, or by a percentage equal to 6 × DF where the DF exceeds 0.33.

Option 1 is not technically acceptable, nor aligned with the requirements of the RBP Pipeline Licence. It is not prudent nor consistent with good practice.

Option 2

Using ILI to maintain the integrity of pipelines is accepted good industry practice and achieves the lowest sustainable cost of providing services relative to other techniques. ILI is a proven technology used worldwide for monitoring pipeline integrity.

ILI is an essential part of the RBP's Pipeline Integrity Management Plan (PIMP) and is in turn necessary to maintain the safety and integrity of services by reducing the risk of a catastrophic failure. The program is necessary to maintain and improve the safety of services and maintain the integrity of services to RBP customers and is of a nature that a prudent service provider would incur.

ILI is also necessary to comply with regulatory obligations (regulatory requirement) and to maintain capacity to meet current levels of demand (by avoiding a requirement to de-rate the pipeline or the weeks/months it would take to restore service following a catastrophic failure).

APA tenders the provision of ILI services on a competitive basis. The works will be subject to APA procurement policies. The works will be carried out by external contractors who demonstrate specific expertise in completing the installation of the facilities in a safe and cost-effective manner. The expenditure can therefore be considered complaint with the expenditure that a prudent service provider acting efficiently would incur.

ILI is the most cost-effective solution and has been approved by the regulators for many other pipeline assets.

Financial assessment

Table 3–2: Financial assessment – Conduct In Line Inspections ($ Real 30 June 2026)

	Description
Option 1: Do Nothing	• Interruptions to customer supply and gas leakage reduces income as will any pipeline failure that leads to a fatality or injury, due to litigation costs and payments for damages. • Regulatory and licence breaches would lead to fines and potentially a loss of the pipeline licence. • These outcomes would severely impact share price and the longevity of the business. • Avoided capex cost in the earlier years will be more than offset by the potential financial and reputational cost of regulatory fines, penalties arising from reputational damage, legal action and the loss of the RBP operating licence. • If a scheduled ILI cannot be completed to meet the date specified in the PIMP, one of the options available to the operator is to set a restricted operating pressure.
Option 2: Conduct In Line Inspections	• Conduct ILI and associated dig & repair in accordance with AS 2885 Pipeline Integrity Management, ensuring defects are identified, validated, and remediated before they threaten pipeline integrity.

APA's preferred option that it believes appropriately balances costs and risks is to conduct ILI on the RBP asset.

2.4. Proposed costs for FY28-FY32

The annual expenditure profile reflects the planned inspection schedule across RBP pipeline segments and accommodates the varying scope and inspection technologies required for each segment.

The proposed costs are summarised in **Table 3–3**, which sets out the estimated annual expenditure by pipeline section and inspection campaign.

Overall, the forecast represents an efficient and proportionate investment to maintain pipeline integrity, comply with regulatory obligations, and support the ongoing safe and reliable operation of the RBP, consistent with the capital expenditure criteria in **NGR Rule 79**.

Table 3–3: Estimated annual cost ILI Program sites ($000's Real 2026-27)

Description	FY28	FY29	FY30	FY31	FY32	Total
DN200 Lytton Lateral - ILI - MFL	577	-	-	-	-	577
DN250 Peat Lateral - ILI	-	693	-	-	-	693
DN300 Metro - ILI - MFL + EMAT	-	-	93	1,658	877	2,629
DN400 - MFL Campaign (3 sections) FY28-30	1,153	578	-	-	-	1,731
DN400 - MFL Campaign (5 sections) FY26-28	373	-	-	-	-	373
FY Total	2,103	1,271	93	1,658	877	6,002

3. Validation Digs

3.1. Project objective and scope

To ensure that any features exceeding acceptance criteria are correctly remediated, and to verify the accuracy of the ILI tool results, validation digs are required following the completion of an ILI and review of the results.

Anomaly assessment and defect repair is a mandatory requirement of AS 2885.3. This requires APA to maintain the RBP's safety and integrity and ability to withstand the internal pressure and other loads.

Following the completion of an Inline Inspection, excavations are routinely undertaken to validate the data obtained from the ILI. These excavations verify the anomaly sizing accuracy and probability of the detection/identification if anomalies are within the statistical specifications of the ILI tool used. For older pipelines, it is common that the number of validation excavations required is less than the total number of anomalies identified by the ILI that require further investigation. These additional excavations are referred to as repair excavations and form the integrity upgrade programme.

For corrosion features, repair requirements have been developed and prioritised based on anomaly assessment of the ILI data using ASME B31G, Modified B31G, and Effective Area calculation methodologies.

A typical integrity upgrade excavation includes:

- Excavating and exposing the pipeline at the location of the anomaly
- Removing the pipeline coating from the pipeline exterior surface
- Inspection and assessment of the anomaly and determination of a repair process
- Repair of the anomaly and refurbishment of the pipeline coating
- Reinstatement of the earth fill around the pipeline and soil surface

3.2. Background

Validation digs are a critical component of the RBP's integrity management program, undertaken to confirm the accuracy and reliability of data obtained from In-Line Inspection (ILI) tools. Following each ILI, physical excavations are required to expose the pipeline, allowing engineers to directly inspect identified anomalies and verify that defect sizing and detection fall within the statistical performance specifications of the inspection technology used.

This process is essential for ensuring compliance with AS 2885.3, which mandates the assessment and remediation of features that could threaten pipeline integrity. Over time, particularly on older pipeline sections, validation digs have proven vital for accurately characterising corrosion, dents, cracking, and other forms of degradation that cannot be fully validated through remote inspection alone.

In addition to confirming ILI performance, validation digs support informed decision-making by improving the accuracy of corrosion growth models, strengthening confidence in reinspection intervals, and ensuring that required repairs are completed to maintain the safety and reliability of the RBP.

3.3. Assessment of options

The options considered for the access arrangement period are:

- Option 1: Do nothing (leave features unmitigated)
- Option 2: Perform Validation Digs Following ILI

3.3.1. Risk assessment

Failing to undertake validation digs after an ILI can result in anomalies being inaccurately sized or incorrectly characterised, leaving potential defects such as corrosion, cracking, dents, or gouges unverified.

Table 4–1: Risk assessment – conduct validation digs

Risk Area	Option 1		Option 2:	
	Likelihood / Impact	Inherent risk rating	Likelihood / Impact	Risk rating
Health & Safety	Remote / Catastrophic	High	Rare / Major	Low
Environment	Remote / Significant	Low	Rare / Significant	Negligible
Operational	Remote / Major	Moderate	Rare / Major	Low
People	Remote / Significant	Low	Rare / Significant	Negligible
Compliance	Remote / Minor	Low	Rare / Significant	Negligible
Reputation & Customer	Remote / Major	Moderate	Rare / Major	Low
Financial	Remote / Significant	Low	Rare / Significant	Negligible
Untreated risk		**High**		**Low**

3.3.2. Option 1

Under this option, no validation digs would be conducted following each In-Line Inspection (ILI). This would significantly increase the risk that detected anomalies are inaccurately sized or incorrectly characterised. Without physical verification, critical defects such as corrosion, cracking, dents, and gouges may remain unvalidated, potentially allowing threats to pipeline integrity to go unaddressed.

This approach is not compliant with AS 2885.3, which requires operators to confirm and remediate features that could compromise pipeline safety. As a result, Option 1 presents a high safety and compliance risk and is not considered prudent nor aligned with good industry practice.

3.3.3. Option 2

This option involves undertaking validation digs after each ILI to verify tool performance, confirm anomaly sizing, and ensure repairs are carried out where required. Validation digs support compliance with AS 2885.3 and provide essential calibration data to improve the accuracy of corrosion growth modelling and future reinspection intervals.

This option reduces uncertainty, increases confidence in the ILI results, and ensures that any features posing potential safety or operational risks are appropriately assessed and remediated. Although it requires ongoing investment, Option 2 represents prudent asset management, reduces lifecycle risk, and supports the safe and reliable operation of the RBP pipeline.

Financial assessment

Table 4–2: Financial assessment – Validation Digs

	Commentary
Option 1: Do Nothing (Carry out only basic pipeline integrity activity; allow pipelines to deteriorate)	• Interruptions to customer supply and gas leakage reduces income as will any pipeline failure that leads to a fatality or injury, due to litigation costs and payments for damages. • Regulatory and licence breaches would lead to fines and potentially a loss of the pipeline licence. • These outcomes would severely impact share price and the longevity of the business. • Avoided capex cost in the earlier years will be more than offset by the potential financial and reputational cost of regulatory fines, penalties arising from reputational damage, legal action and the loss of the RBP operating licence.
Option 2: Carry out pipeline Validation Digs	• Conduct ILI and associated dig & repair in accordance with AS 2885 Pipeline Integrity Management, ensuring defects are identified, validated, and remediated before they threaten pipeline integrity. • Excavation, integrity works and new coating upgrades and repair

The preferred option that appropriately balances costs and risks is to conduct Validation Digs

3.4. Proposed costs for FY28-FY32

The total forecast capital expenditure for Validation Digs over FY28–FY32 is aligned with the planned ILI inspection program. This reflects the expected number, complexity, and location of excavations required to validate inspection results across the RBP. The expenditure profile varies year-to-year in line with inspection campaigns and avoids inefficient front-loading or duplication of works.

The proposed costs are summarised in **Table 4–3**, which sets out the estimated annual expenditure by pipeline segment and inspection campaign. The forecast represents a **reasonable, cost-reflective, and efficient investment** to maintain asset integrity, comply with regulatory obligations, and support the continued safe and reliable operation of the RBP, consistent with the capital expenditure criteria in **NGR Rule 79**.

Table 4-1: Estimated annual Validation Digs ($000's Real 2026-27)

Description	FY28	FY29	FY30	FY31	FY32	Total
DN250 Peat Lateral - Validation Dig ILI	-	-	1,043	-	-	**1,043**
DN300 Metro - Validation dig ILI	1,845	-	-	-	-	**1,845**
DN400 - Validation Dig ILI (3 sections)	-	982	985	989	262	**3,219**
DN400 - Validation Dig ILI (5 sections)	-	982	985	989	262	**3,219**

DN200 Lytton Lateral - Validation Dig ILI	923	-	-	-	-	923
FY Total	2,768	1,964	3,013	1,978	525	10,249

4. Safety Critical Digs

4.1. Project objective and scope

The Safety Critical Digs program addresses defects that present an immediate threat to the safety and integrity of the RBP. These excavations are undertaken when anomalies identified through ILI, CP assessments, or field observations exceed the acceptance limits defined in AS 2885.3 and therefore cannot be deferred.

4.2. Background

The DN250 pipeline—constructed in 1968–69 with over-the-ditch-applied polyethylene tape coating—is classified as a "vintage" asset and requires a significantly higher level of integrity management due to advanced coating deterioration and elevated corrosion risk. Disbondment of the original tape coating results in isolated shielding of cathodic protection, enabling external corrosion to progress unchecked across substantial lengths of the DN250 asset.

Sections A–F of the DN250 pipeline are currently suspended with suspension taking place between June 2019 and April 2025 inline with the current Access Arrangement business case. As these sections are currently suspended, safety dig-ups and further direct assessments are largely deferred unless that section is returned from suspension. Each suspended section is maintained a very low but positive pressure to prevent oxygen ingress and internal corrosion. These pressures are monitored by telemetry. Should a loss of pressure be detected integrity management actions are still required.

4.3. Assessment of options

The options considered for the access arrangement period are:

— Option 1: Do nothing

— Option 2: Undertake Safety Critical Digs

4.3.1. Risk assessment

Table 5–1: Risk assessment – Safety Critical Digs

Risk Area	Option 1		Option 2:	
	Likelihood / Impact	Inherent risk rating	Likelihood / Impact	Risk rating
Health & Safety	Remote / Catastrophic	High	Rare / Major	Low
Environment	Remote / Significant	Low	Rare / Significant	Negligible
Operational	Remote / Major	Moderate	Rare / Major	Low
People	Remote / Significant	Low	Rare / Significant	Negligible
Compliance	Remote / Minor	Low	Rare / Significant	Negligible
Reputation & Customer	Remote / Major	Moderate	Rare / Major	Low
Financial	Remote / Significant	Low	Rare / Significant	Negligible
Untreated risk		**High**		**Low**

Option 1

Under this option, no Safety Critical Digs would be undertaken, and defects identified through ILI, CP assessments, or field observations would remain unaddressed. For the DN250 pipeline—particularly the remaining in-service Brassall to Bellbird Park segment, this would leave known corrosion, coating disbondment, and potential ERW seam weld defects unmanaged. The risk of loss of containment would remain high, and the approach would be non-compliant with AS 2885.3, which requires immediate remediation of anomalies exceeding acceptance criteria. This option is therefore not technically acceptable nor prudent.

Option 2

Undertaking Safety Critical Digs ensures that any defects identified through ILI, CP assessments or field observations that exceed AS 2885.3 acceptance criteria are immediately excavated and remediated. This is critical for the DN250 pipeline, particularly the remaining in-service Brassall to Bellbird Park segment, which continues to exhibit corrosion-driven degradation, coating disbondment, and potential ERW seam-weld abnormalities. Completing Safety Critical Digs maintains compliance with AS 2885.3, reduces the likelihood of loss-of-containment events, and represents prudent and accepted good industry practice for managing high-risk legacy pipeline assets.

Financial assessment

Table 5–2: Financial assessment – Safety Critical Digs ($ Real 30 June 2026)

	Commentary
Option 1: Do Nothing (Carry out only basic pipeline integrity activity; allow pipelines to deteriorate)	• Interruptions to customer supply and gas leakage reduces income (RBP revenue per day) • litigation costs and payments for damages as will any pipeline failure that leads to a fatality or injury • Regulatory and licence breaches would lead to fines and potentially a loss of the pipeline licence. (max possible fine for safety breach under HSE and Qld Resource legislation) • These outcomes would severely impact share price and the longevity of the business.
Option 2: Carry out pipeline Safety Critical Digs	• Conduct ILI and associated dig & repair in accordance with AS 2885 Pipeline Integrity Management, ensuring defects are identified, validated, and remediated before they threaten pipeline integrity. • Excavation, integrity works and new coating upgrades and repair

The preferred option that appropriately balances costs and risks is Option 2, Carry out Safety Critical Digs.

4.4. Proposed cost for FY28-FY32

The forecast expenditure reflects the expected volume of non-deferrable excavations required to remediate defects that exceed acceptance criteria under **AS 2885.3** and therefore present an immediate risk to pipeline safety or integrity. Safety Critical Digs are inherently driven by inspection outcomes and field observations and cannot be precisely forecast in advance. The estimate has therefore been developed using a structured and evidence-based approach that integrates both historical performance and forward-looking inspection activity.

Historical delivery on the RBP indicates an average of approximately eight safety critical digs per annum, based on observed defect rates and past repair volumes. While this provides a relevant baseline, reliance on historical averages alone is not considered sufficiently robust for forecasting purposes, as it does not reflect the timing and scope of planned inspection activities or changes in asset condition.

To address this, APA has applied an internal estimation methodology that links forecast dig volumes to the planned pigging and In-Line Inspection (ILI) program over the Access Arrangement period. This approach recognises that safety critical defects are predominantly identified through inspection and are therefore correlated with ILI campaign timing, rather than occurring uniformly year-on-year.

Under this approach:

- Forecast dig volumes are aligned to known ILI activities, reflecting when defect identification is most likely to occur
- Estimates consider relevant asset characteristics, including pipeline age, condition, and historical defect behaviour
- Allowances are made for time-critical defects and inspection variability, consistent with integrity management requirements under AS 2885.3
- The resulting profile reflects a non-linear distribution of works, rather than a simple steady-state annual assumption

Application of this methodology results in a forecast that is more targeted and responsive to the underlying risk drivers than a simple extrapolation of historical averages. In particular, it avoids systematic over-estimation in years without significant inspection activity, while still maintaining sufficient provision for emergent defects.

The estimate also differentiates between complex and non-complex dig-ups, recognising that cost is materially influenced by location and access constraints (e.g. urban areas, road and rail crossings). The proportion of complex digs has been developed based on the spatial characteristics of the RBP and recent delivery experience.

The resulting expenditure profile and expected mix of dig types are summarised in Tables 5-3 and 5-4.

Table 5–3: Estimated yearly cost of Safety Critical Digs ($'000s Real 2026-27)

Description	FY28	FY29	FY30	FY31	FY32	Total
Safety Critical Digs (Complex)	461	1387	464	1396	467	4,174
Safety Critical Digs (Non-complex)	259	1300	782	785	262	3,390
FY Total	721	2,686	1,246	2,182	729	7,564

Table 5–4: Estimated yearly breakdown of complex & non-complex digs

Description	FY28	FY29	FY30	FY31	FY32	Total
Safety Critical Digs (Complex)	1	3	1	3	1	9
Safety Critical Digs (Non-complex)	1	5	3	3	1	13
FY Total	2	8	4	6	2	22

5. Cathodic Protection

5.1. Project objective and scope

Cathodic protection (CP) is a critical integrity control for the Roma to Brisbane Pipeline (RBP), providing protection against external corrosion for all buried steel pipeline assets. The proposed CP capital program for the FY28–FY32 access arrangement period is required to maintain compliance with applicable Australian Standards, pipeline licence conditions, and APA's Pipeline Integrity Management Plan (PIMP).

The scope of the proposed program includes:

— replacement of depleted anode beds;

— replacement of ageing transformer–rectifier (TR) units that have reached end of service life;

— installation of new CP systems where surveys identify inadequate protection coverage, particularly on DN300 sections; and

— ongoing management of AC interference and CP performance monitoring.

Although segments of the DN250 pipeline are suspended or progressively being retired from service, these sections remain electrically bonded to the broader CP system and therefore require continued protection to prevent further corrosion until full decommissioning is completed.

The proposed expenditure is targeted, risk-based, and limited to the works necessary to maintain effective corrosion protection across the RBP.

5.2. Background

Cathodic protection (CP) is a mandatory integrity control for buried steel pipelines and is required under AS 2832.1, AS 2885.3, and the RBP pipeline licence. Although large sections of the DN250 pipeline are no longer operating, the asset has not been decommissioned and remains physically in the ground, electrically bonded, and registered. As such, APA is required to continue demonstrating that corrosion risks are being effectively managed.

At the current time, sections of the DN250 remain partially in use, while other sections are in a suspended state. Where suspension has occurred, operating pressure has already been reduced, materially lowering rupture risk. As customers are progressively removed and pressure is further reduced, corrosion risk and the required level of CP intervention also decline. This creates opportunities over time to optimise CP delivery, including:

- applying alternative CP performance criteria appropriate for suspended pipelines (e.g. polarisation-based criteria);
- reducing CP current outputs; and
- rationalising the number of CP installations and test points.

These optimisation opportunities are already being progressed. The Wallumbilla-to-Brassall section has accepted revised criteria, and a formal study is underway on the Brassall-to-Kogan section to further reduce CP requirements and cost. In addition, as anode beds progressively deplete, the need for replacement is assessed on a case-by-case basis with the objective of minimising capital expenditure while maintaining compliance.

Complete removal of CP on the DN250 is not viable. Doing so would result in uncontrolled corrosion of a large legacy asset, increase safety and environmental risk, compromise compliance, and potentially impact adjacent assets, including third-party pipelines electrically coupled to the RBP CP system. Ongoing CP is also required to maintain CP registration and support leak survey obligations until full decommissioning is achieved.

The forecast CP expenditure reflects uncertainty during this transition period and represents APA's best estimate of the lowest sustainable cost required to maintain the integrity of the DN250 while it remains suspended rather than decommissioned. While alternative criteria and optimisation measures are expected to reduce costs over time, maintaining CP on the DN250 remains the lowest-cost and lowest-risk option when compared to cessation of CP, premature decommissioning, or reactive integrity intervention.

5.3. Assessment of options

The options considered for the access arrangement period are:

— Option 1: Do nothing

— Option 2: Repair and upgrade existing CP systems (preferred option)

— Option 3: Full replacement of CP systems

5.3.1. Risk assessment

Table 6–1: Risk assessment – CP

Risk Area	Option 1		Option 2:	
	Likelihood / Impact	Inherent risk rating	Likelihood / Impact	Risk rating
Health & Safety	Remote / Minor	Negligible	Rare / Minor	Negligible
Environment	Unlikely / Minor	Low	Remote / Minor	Negligible
Operational	n/a		n/a	
People	n/a		n/a	
Compliance	Unlikely / Major	High	Remote / Significant	Low
Reputation & Customer	Unlikely / Significant	Moderate	Remote / Significant	Low
Financial	Unlikely / Minor	Low	Remote / Minor	Negligible
Untreated risk		**High**		**Low**

5.3.2. Financial assessment

Table 6–2: Financial assessment – CP ($ Real 30 June 2026)

	Commentary
Option 1: Do Nothing	• Defers near-term CP capital expenditure. • Does not address ageing and end-of-life CP assets. • Increased risk of non-compliance with AS 2832.1. • Higher likelihood of corrosion escalation, unplanned repairs, and integrity incidents. • Short-term savings likely outweighed by higher long-term remediation and compliance costs.
Option 2: Repair and upgrade	• Targeted replacement of depleted anodes and ageing TR units. • Installation of new CP systems where protection is inadequate.

existing CP systems (preferred option)	• Maintains compliance with AS 2832.1 and AS 2885.3. • Reduces corrosion risk and avoids costly reactive interventions. • Represents prudent, efficient and risk-based expenditure consistent with NGR requirements.

Option 1

This option would retain existing CP assets without renewal or upgrade. While basic monitoring could continue, this option would not address depleted anode beds, failing TR units, or known CP deficiencies. Over time, corrosion risk would increase and compliance with AS 2832.1 would not be assured. This option is not prudent and does not meet legislative, licence, or safety obligations.

Option 2

This option involves targeted replacement of end-of-life CP assets, installation of new CP systems where surveys demonstrate inadequate protection, and continued CP monitoring and optimisation. Works are prioritised based on risk, asset condition, and exposure, and are limited to what is required to maintain effective corrosion protection.

Option 3

Wholesale replacement of all CP assets would exceed what is required to achieve compliance and safety outcomes and would not represent efficient expenditure. This option was not progressed further.

5.4. Proposed cost for FY28-FY32

Total forecast cathodic protection expenditure for the FY28–FY32 access arrangement period is **$11.5 million (real 30 June 2026)**. This includes:

- ongoing CP program works on DN400 and DN300 pipelines; and
- continued CP management and interference mitigation associated with DN250 assets until full decommissioning is completed.

The expenditure profile reflects steady, predictable investment aligned with asset needs and avoids cost volatility associated with reactive or failure-driven interventions.

Table 6–3: Annual estimated cost of CP Program ($'000s Real 2026-27)

Description	FY28	FY29	FY30	FY31	FY32	Total
CP Program	1,730	1,733	1,738	1,746	1,750	8,697
CP Interference (DN250) and Registration	923	924	927	931	933	4,638
FY Total	2,653	2,657	2,666	2,676	2,683	13,335

6. Pigging Enablement Upgrades

6.1. Project objective and scope

Pigging enablement upgrades are required to ensure the Roma to Brisbane Pipeline (RBP) retains the capability to undertake in-line inspection (ILI) and other pigging activities necessary to manage pipeline integrity in accordance with the Pipeline Integrity Management Plan (PIMP) and AS 2885.3.

Historically, pigging of the DN300 pipeline was undertaken from Bellbird Park using facilities associated with the DN250 pipeline. With the planned suspension of the remaining sections of the DN250, pigging capability must be established at Ellengrove to ensure the DN300 can continue to be pigged safely and in accordance with integrity requirements.

The scope of works for the FY28–FY32 access arrangement period includes targeted upgrades at specific RBP locations where existing facilities do not support safe or reliable pigging operations. The key elements of the program are:

- installation of pig launching and receiving facilities on the DN300 pipeline at Ellengrove to enable routine pigging and ILI; and
- safety-driven replacement of age degraded equipment at the DN300 pig receiver located at the South-East Area (SEA) compound to address known operational and safety deficiencies.

These upgrades are limited to locations where pigging capability is currently constrained and are necessary to maintain the ongoing integrity of the pipeline system.

6.2. Background

In-line inspection is a critical integrity tool for detecting corrosion, cracking, dents and other defects that cannot be reliably identified through external inspection alone. Without pigging capability, APA would be unable to:

- perform mandatory ILI on affected pipeline sections;
- maintain confidence in pipeline condition between inspection cycles; or
- comply with integrity management requirements under AS 2885.3 and the RBP pipeline licence.

At Ellengrove, the DN300 pipeline currently lacks pigging capability. If no enablement works are undertaken at this location, future inspections of this pipeline section would not be practicable, increasing integrity risk and restricting APA’s ability to proactively manage degradation.

At the SEA compound, the existing pig receiver is suffering for age related degradation of it’s critical safety isolation valves, nor does the design accommodate current standards for isolation capability and liquids handling. Operational workarounds are currently required, exposing personnel, the public and the environment to avoidable safety and environmental risks. Design changes are most efficiently applied at the point where the existing equipment is at end of life and needing replacement.

Given the age of the DN300 asset and its role within the RBP system, maintaining pigging capability is necessary to support continued safe and reliable operation.

6.3. Assessment of options

The options considered for the access arrangement period are:

- Option 1: Do Nothing
- Option 2: Implement the Pigging enablement upgrades (preferred)

6.3.1. Risk assessment

The primary risk addressed by the Pigging Enablement Upgrades is the inability to reliably inspect and monitor the condition of affected sections of the DN300 pipeline using in-line inspection (ILI). Without pigging capability, integrity threats such as internal corrosion, cracking, metal loss or deformation may remain undetected between inspection cycles, increasing the likelihood of loss-of-containment events.

While the planned suspension of the DN250 pipeline necessitates this upgrade, the need has been managed to date as the next DN300 pigging run is not scheduled until 2030, allowing the change to be accommodated within the current program.

The absence of pigging capability also limits APA's ability to comply with the inspection requirements set out in the Pipeline Integrity Management Plan (PIMP), AS 2885.3, and the RBP pipeline licence. In such circumstances, APA may be required to rely on conservative operational controls, including cascading pressure restrictions due to the DN300 route through densely housed suburbs.

At the SEA compound, deficiencies in the existing pig receiver configuration introduce avoidable safety and environmental risks during pigging operations, including inadequate isolation capability and uncontrolled release of gas or liquids. Continued reliance on procedural workarounds elevates personnel safety risk and is not consistent with accepted good industry practice.

Implementation of the Pigging Enablement Upgrades materially reduces these risks by restoring full pigging capability, enabling mandatory ILI, and eliminating identified safety hazards at existing facilities. With the upgrades in place, residual risk is assessed as low and consistent with prudent and accepted industry practice for gas transmission pipeline operations.

The program is non-recurring in nature and avoids future escalation in integrity management costs.

Table 5–1: Risk assessment – Pigging enablement upgrades

Risk Area	Option 1		Option 2:	
	Likelihood / Impact	Inherent risk rating	Likelihood / Impact	Risk rating
Health & Safety	Remote / Catastrophic	High	Rare / Catastrophic	Moderate
Environment	Remote / Significant	Low	Rare / Significant	Negligible
Operational	Remote / Significant	Low	Rare / Significant	Negligible
People	Remote / Significant	Low	Rare / Significant	Negligible
Compliance	Remote / Significant	Low	Rare / Significant	Negligible
Reputation & Customer	Remote / Major	Moderate	Rare / Major	Low
Financial	Remote / Significant	Low	Rare / Significant	Negligible
Untreated risk		**High**		**Moderate**

6.3.2. Financial assessment

Table 7–2: Financial assessment – Pigging enablement upgrades ($ Real 30 June 2026)

	Commentary
Option 1: Do Nothing	• Avoids near-term capital expenditure on pigging infrastructure. • Inability to undertake mandatory pigging and in-line inspection on affected DN300 sections. • Increased likelihood of undetected integrity defects leading to higher future remediation costs. • Potential for pipeline pressure restrictions or operational limitations to manage integrity risk. • Higher long-term costs driven by reactive repairs, safety incidents, or premature asset replacement.
Option 2: Implement the Pigging enablement project (preferred)	• Enables mandatory pigging and ILI in accordance with the PIMP and AS 2885.3. • Reduces lifecycle costs by supporting early detection and remediation of integrity threats. • Eliminates reliance on operational workarounds that increase safety and environmental risk. • Avoids inefficient costs associated with pipeline de-rating, service interruptions, or emergency repairs. • Represents prudent, efficient and safety-driven expenditure consistent with NGR requirements.

Option 1

Under this option, no pigging enablement or safety upgrades would be undertaken. Pigging and ILI would remain unavailable on affected sections of the DN300 pipeline, and existing operational risks at the SEA compound would persist. This option would materially increase integrity, safety and compliance risk and is not consistent with good industry practice.

Option 2

This option involves installing the minimum infrastructure required to enable pigging and addressing identified safety deficiencies at existing facilities. The scope is targeted and proportionate, addressing only those locations where pigging capability or safety outcomes cannot be achieved through operational controls alone.

Option 2 ensures APA can continue to meet integrity obligations, manage risk proactively, and safely operate pigging facilities.

6.4. Proposed cost for FY28-FY32

This expenditure relates primarily to safety and capability upgrades at identified DN300 facilities and is consistent with recent project delivery costs for comparable works.

The program is non-recurring in nature and avoids future escalation in integrity management costs.

Table 7–3: Annual estimated cost of ILI Upgrades ($'000s Real 2026-27)

Description	FY28	FY29	FY30	FY31	FY32	Total
DN300 Pig Receiver Safety Upgrades (SEA Compound)	-	2,114	-	-	-	**2,114**

7. Enhanced Methane Survey

7.1. Project objective and scope

The objective of the Enhanced Methane Survey program is to strengthen leak detection capability **across the Roma to Brisbane Pipeline (RBP)** by supplementing established integrity management activities with **direct, high-sensitivity methane measurement technologies**.

While the RBP integrity framework is primarily designed to identify and manage structural threats through in-line inspection (ILI), cathodic protection (CP) monitoring, and targeted excavations, methane surveys provide an additional and complementary control by focusing on **direct detection of loss-of-containment events**. This enhances APA's ability to identify, locate, and respond to methane emissions across the pipeline system before they escalate into safety, environmental, or service impacts.

The scope of the program includes:

— deployment of advanced methane detection technologies (including ground-based and, where appropriate, mobile or aerial surveys);

— collection of georeferenced and time-stamped methane measurement data across defined sections of the RBP;

— classification and prioritisation of detected emissions in accordance with established leak management protocols; and

— integration of survey outcomes into the Pipeline Integrity Management Plan (PIMP) to inform investigation, repair, and longer-term integrity planning.

The program is applied on a **risk-informed and targeted basis across the RBP**, rather than as a continuous or blanket monitoring regime, ensuring that the proposed expenditure remains proportionate and efficient.

7.2. Background

APA manages the RBP using a mature integrity management framework aligned with AS 2885 and licence requirements. This framework incorporates a range of preventative and monitoring controls, including:

— periodic in-line inspection using multiple technologies;

— cathodic protection systems supported by routine surveys;

— validation and safety-critical excavations; and

— routine patrols and operational surveillance.

These controls are effective in identifying structural defects and corrosion-related threats; however, they do not always provide early visibility of **small, emergent methane leaks**, particularly those arising between inspection cycles or associated with fittings, joints, or ageing infrastructure components.

In response to this gap, APA has developed and implemented enhanced methane measurement programs across other major transmission assets within its portfolio. These programs have demonstrated that:

— direct methane measurement provides a more accurate and asset-specific understanding of emissions than emissions-factor-based estimation methods;

— modern methane detection technologies are capable of identifying low-rate emissions with high confidence and precise location data; and

— targeted surveys can be efficiently integrated into existing asset management and integrity processes without duplication or unnecessary cost.

The proposed enhanced methane survey for the RBP applies these learnings in a **measured and proportionate manner**, supporting continuous improvement in integrity assurance, environmental performance, and transparency.

7.3. Assessment of options

The options considered for the access arrangement period are:

— Option 1: Do Nothing

— Option 2: Implement Enhanced Methane Survey (Preferred)

7.3.1. Risk assessment

The primary risk addressed by the Enhanced Methane Survey relates to the potential for methane leaks to remain undetected between scheduled integrity inspections or routine patrols. While the RBP benefits from a mature integrity management framework, existing controls are predominantly focused on identifying structural defects rather than directly detecting small or emerging loss-of-containment events. Undetected methane emissions present safety, environmental, compliance, and reputational risks, particularly given the length, age profile, and geographic reach of the RBP. Introducing enhanced methane detection provides an additional, independent control that materially reduces the likelihood and duration of undetected emissions, improves the timeliness of intervention, and lowers the residual risk across the pipeline system to an acceptable and manageable level. The residual risk with the enhanced survey in place is assessed as low and consistent with prudent and accepted good industry practice for major gas transmission assets.

Table 8–1: Risk assessment – Enhanced Methane Survey

Risk Area	Potential Impact	Option 1	Option 2	
		Inherent risk rating	Likelihood / Impact	Risk rating
Health & Safety	Fatality or injury	Moderate	Rare / Significant	Negligible
Environment	n/a	n/a	n/a	n/a
Operational	Disruption 1-3 months	Low	Rare / Minor	Negligible
Compliance	Regulatory breach	Moderate	Rare / Minor	Negligible
Reputation & Customers	Adverse media, negative feedback	Moderate	Rare / Significant	Negligible
Financial	Repair costs	Moderate	Rare / Significant	Negligible
Untreated risk		**Moderate**		**Negligible**

7.3.2. Financial assessment

Table 8–2: Financial assessment – Enhanced Methane Survey ($ Real 30 June 2026)

	Commentary
Option 1: Do Nothing	• Avoids short-term expenditure on enhanced methane detection. • Relies on patrols, CP data, and indirect indicators with limited leak-detection sensitivity. • Increased risk of undetected low-rate emissions persisting over time. • Potential for higher downstream repair costs due to delayed detection. • Greater exposure to environmental, regulatory and reputational risk.

Option 2: Implement Enhanced Methane Survey (Preferred)	• Enables early detection and precise location of methane emissions. • Reduces lifecycle costs by preventing escalation of minor leaks. • Improves efficiency by targeting investigation and repair activities. • Complements existing integrity programs without duplication. • Represents prudent, risk-based and industry-accepted expenditure.

Option 1

Under this option, methane leak identification would continue to rely on existing integrity controls, periodic patrols, and indirect indicators such as CP performance and operational data. While these measures provide baseline assurance, they have limited sensitivity for detecting small or developing methane leaks across a complex, geographically extensive pipeline system.

This option increases the likelihood that minor emissions remain undetected for extended periods, potentially leading to higher cumulative emissions, delayed intervention, and heightened regulatory or reputational risk.

Option 2

This option introduces targeted enhanced methane surveys across the RBP to strengthen leak detection capability and improve the timeliness and accuracy of emissions identification.

Consistent with demonstrated outcomes from APA's broader methane measurement programs, this approach:

— materially improves sensitivity compared to conventional patrol-based detection;

— enables accurate localisation and prioritisation of emission sources using GPS-referenced data;

— supports efficient deployment of investigation and repair resources; and

— integrates seamlessly with existing integrity and maintenance workflows.

Importantly, the enhanced methane survey is not intended to replace established integrity activities, but to complement them, addressing residual risks that are not fully mitigated through existing controls. Application of the technology is informed by asset risk profile and operational context, ensuring the program remains efficient and proportionate.

Option 2 delivers improved safety, environmental, compliance, and reputational outcomes relative to Option 1 and represents accepted good industry practice for modern transmission pipeline operations.

7.4. Proposed cost for FY28-FY32

The proposed expenditure reflects the efficient cost of undertaking a targeted enhanced methane survey across the RBP during the Access Arrangement period. Cost estimates are based on current market pricing and informed by APA's recent experience implementing similar programs on other major transmission assets.

The scope has been deliberately designed to:

— avoid duplication with existing integrity activities;

— focus surveys where they provide incremental value; and

— limit the frequency of campaigns to those necessary to achieve assurance objectives.

APA expects that continued technological development and increased industry adoption of methane detection technologies will place downward pressure on unit costs over time. The survey will take place in FY27 and then again during the Access Arrangement period.

The proposed expenditure is consistent with the National Gas Rules as it:

- is necessary to maintain and improve the safety and integrity of pipeline services;
- supports proactive identification and management of loss-of-containment risks across the RBP;
- aligns with demonstrated industry practice and APA's experience on comparable sized assets (SWQP (Qld), MSP (NSW)); and
- represents prudent and efficient expenditure that a service provider acting efficiently and responsibly would incur.

Table 8–3: Annual estimated cost of Enhanced Methane Survey ($'000s Real 30 June 2026)

Description	FY28	FY29	FY30	FY31	FY32	Total
Enhanced Methane Survey	-	-	2,897	-	-	2,897

DN250 – Supply Security Project Business Case

Roma to Brisbane Gas Pipeline
Access Arrangement 2028–32

29 May 2026

Contents

1. Overview

Number/ identifier	A-2_DN250
Description of Issue/ Project	The DN250 section of the RBP between Brassall and Ellengrove is nearing end-of-life and exhibiting increasing integrity degradation, with remaining defects located in complex, high-cost dig environments. Continuing to operate the DN250 would require extensive and escalating integrity works that are neither prudent nor efficient. Transitioning customers to the DN400 and suspending the DN250 provides a lower-cost, lower-risk long-term solution, avoiding substantial future dig expenditure and ensuring safe, reliable supply. The preferred option aligns with NGR 79 and represents the lowest sustainable cost for maintaining service integrity
Options considered	The following options have been considered: DN250: 4. Option 1: Continue the pipeline dig program on the DN250 **5. Option 2: Continue suspension of DN250 Pipeline and decommissioning of surface assets no longer required.** **6.** Option 3 - Finalise stage 2a and defer further works 7. Option 4 – replace the DN250 pipeline AC Mitigation: 1. Option 1 – Do Nothing: Leaves AC voltage levels uncontrolled. Not prudent. **2. Option 2 – Targeted AC Mitigation (Preferred): Risk-based mitigation at locations with elevated AC interference.** 3. Option 3 – Maximum Mitigation: Full-corridor mitigation; effective but significantly higher cost with limited incremental benefit.
Proposed Solution	Following completion of Phase 2a, Phase 3 of the Supply Security Project will continue towards suspension of the DN250 Pipeline and decommissioning of surface assets no longer required.
Estimated Cost	$16.4 million
Relevant standards	• AS 2885.3 Pipelines: Gas and Liquid Petroleum Operations and Maintenance. • RBP Pipeline Licence
Stakeholder Engagement	• Scope discussed during RBP Access Arrangement Stakeholder Meetings #3 (25/11/2025); #4 (10/02/2026); and #5 (31/03/2026)
Consistency with National Gas Rules (NGR)	As it reduces the ongoing capital cost and improves the safety and reliability of the RBP the pipeline integrity management work complies with the capital expenditure criteria in Section 79 of the NGR because it: • is necessary to maintain and improve the safety and integrity of services (79(2)(c)(i) and (ii)); and

	• 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 (79(1)(a)).

2. Program details

2.1. Background

The Roma to Brisbane Pipeline (RBP) comprises parallel DN250 and DN400 gas transmission pipelines sharing a common easement from Wallumbilla to metropolitan Brisbane. The DN250 is nearing end-of-life and exhibiting progressive integrity degradation, with remaining defects increasingly located in complex, high-cost dig environments such as beneath the Ipswich Motorway and within flood-prone areas. Continuing to operate the DN250 would require extensive and escalating integrity works that are neither prudent nor efficient.

APA has been implementing a staged program across multiple access arrangement periods to transition customers from the DN250 to the more robust DN400 pipeline and suspend the DN250 in sections where it is no longer required. Completed phases have suspended the DN250 between Wallumbilla and Brassall, with Phase 2a currently addressing the remaining sections between Brassall and Bellbird Park. Once transitioned, customers are reliably supplied from the DN400 via upgraded pressure regulation, heating and backup power systems.

2.2. Summary of options considered

This business case addresses two related components of the DN250 program: the DN250 Supply Security Project (Section 3) and AC Mitigation (Section 4). The following options were assessed for each component.

DN250 Suspension (Section 3)

1. **Option 1 – Do Nothing:** Continue operating the DN250 and maintain integrity through ongoing dig programs. Not prudent due to the scale and cost of 139 planned digs in constrained locations.
2. **Option 2 – Transition customers to the DN400, suspend the DN250 and decommission redundant surface assets (Preferred):** Maintains reliable supply while avoiding substantial future integrity expenditure. Estimated cost $12.889 million.
3. **Option 3 – Finalise Phase 2a and defer further works:** Defers rather than avoids expenditure and is not consistent with prudent asset management.
4. **Option 4 – Replace the DN250 pipeline:** Indicative cost of approximately $300 million for 396.8 km of new pipeline, duplicating capacity already provided by the DN400. Not prudent or efficient.

AC Mitigation (Section 4)

1. **Option 1 – Do Nothing:** Leaves AC voltage levels uncontrolled. Not prudent.
2. **Option 2 – Targeted AC Mitigation (Preferred):** Risk-based mitigation at locations with elevated AC interference. Estimated cost $1.250 million.
3. **Option 3 – Maximum Mitigation:** Full-corridor mitigation; effective but significantly higher cost with limited incremental benefit.

Detailed options assessment, risk analysis and financial evaluation for each component are presented in Sections 3 and 4 respectively.

2.3. Consistency with the National Gas Rules and other regulations

The proposed program satisfies the capital expenditure criteria under Rule 79 of the NGR, as it is necessary to maintain the integrity and safety of pipeline services and reflects expenditure that a prudent service provider acting efficiently would incur. The works align with the requirements of AS 2885.3 (Operations and Maintenance) and applicable pipeline licence obligations. Suspending the DN250 avoids significant future integrity costs while ensuring customer supply is delivered through the more robust DN400 asset, achieving the lowest sustainable cost of service provision

2.4. Proposed costs for FY28-FY32

The expenditure has been developed on a prudent, efficient, and evidence-based basis, drawing on asset condition data, detailed scope development, historical delivery experience, and current market-tested contractor rates under APA's national vendor arrangements. The proposed program represents the **lowest sustainable cost** approach to maintaining safety, reliability, and continuity of service, consistent with the capital expenditure criteria in **NGR Rule 79**.

Table 2–3 Total cost for DN250 Supply Security business case ($'000s Real 2026-27)

Description	FY28	FY29	FY30	FY31	FY32	Total
RBP - DN250 Suspension	4,795	5,525	1,171	1,155	2,274	**14,920**
RBP - DN250 AC Mitigation (Oakey to Bellbird Park)	288	289	290	291	292	**1,449**
FY Total	**5,084**	**5,814**	**1,460**	**1,446**	**2,565**	**16,369**

3. DN250 Suspension

3.1. Project objective and scope

Phase 2a of the DN250 Supply Security Program addresses the remaining operational sections of the DN250 pipeline between Riverview and Bellbird Park. The objective of this phase is to ensure continuity of safe and reliable gas supply to existing DN250 customers while enabling the progressive suspension of the DN250 asset as its mechanical integrity continues to deteriorate. The project will transition customer supply to the DN400 pipeline, supported by the installation of dual heating, pressure regulation and backup power systems where required, allowing integrity works to proceed without customer impact. Phase 2a forms a critical enabling step for Phase 3, which will complete the suspension and decommissioning of remaining DN250 infrastructure.

Phase 3 of the DN250 Supply Security Program completes the transition away from the ageing DN250 pipeline by fully suspending the remaining sections and decommissioning above-ground facilities across six legacy compressor stations (Yuleba, Condamine, Kogan, Dalby, Oakey and Gatton). These facilities are no longer required once gas transmission is fully redirected to the DN400. Decommissioning includes the removal of DN250-related equipment, demolition of obsolete buildings and structures, and rationalisation of site layouts. DN250 pipework will remain in situ, but all redundant equipment will be removed to reduce long-term maintenance obligations and safety risk. This phase ensures supply reliability by relying exclusively on the DN400 pipeline, supported by upgraded pressure regulation, heating and backup power systems implemented under earlier phases.

3.2. Background

The DN250 pipeline is experiencing age-related integrity degradation, and its remaining defects are increasingly located in challenging areas—such as beneath transport corridors or within flood-prone land—making excavation complex, costly and high-risk. While large portions of the DN250 have already been suspended (Kogan to Brassall), the Brassall to Bellbird Park segment must remain temporarily operational due to land-access constraints at Riverview and flooding issues at Redbank. Phase 2a therefore focuses on establishing alternative supply paths and preparing the network for the safe suspension of the remaining DN250 sections by redirecting flows through the DN400. This approach ensures that customer supply is maintained while avoiding future costly and impractical dig programs on the DN250.

3.3. Assessment of options

- Option 1 – Do Nothing
- Option 2 – Transition Supply to DN400, suspend DN250 & Fully Decommission DN250 Surface Assets (Preferred Option)
- Option 3 – Finalise Stage 2a and defer further works
- Option 4 – replace the DN250 Pipeline

Option 1 – Do Nothing

Under this option, the DN250 would continue to operate without intervention. This would necessitate extensive integrity dig programs in inaccessible urban locations, including areas under and adjacent to the Ipswich Motorway, requiring multi-year planning and approvals and resulting in multi-million-dollar costs. Continued operation would also exacerbate corrosion risks, compromise compliance with AS 2885.3, and expose customers at Redbank and Riverview to increased supply-security risk. As such, Option 1 is not prudent, not financially viable, and inconsistent with good industry practice.

Option 2 – Transition Supply to DN400 and Suspend DN250 (Preferred Option)

Option 2 replaces the DN250 supply path with the DN400 pipeline, enabling safe suspension of the DN250 from Riverview to Bellbird Park. This option maintains supply security for existing customers, mitigates emerging integrity risks, and avoids the substantial future expenditure associated with the DN250 dig program. Option 2 is the only credible and practicable solution, delivering a more reliable supply path and ensuring compliance with relevant standards while avoiding disproportionate future costs.

Option 3 - Finalise stage 2a and defer further works.

Under this option, APA would complete the approved Stage 2a customer transitions to the DN400 pipeline but would not proceed with broader suspension or decommissioning of the DN250. The DN250 and associated facilities would remain in situ, subject to reactive management of integrity and safety risks.

While this option reduces near-term capital expenditure, it does not minimise costs over the life of the asset. Retention of the DN250 would result in ongoing operating expenditure associated with integrity monitoring, cathodic protection, AC interference management and periodic remediation, despite the pipeline no longer providing material transmission services.

In addition, ageing surface facilities would continue to present safety, compliance and maintenance risks, with these risks expected to increase over time as the asset further deteriorates. Deferring suspension works would therefore expose consumers to higher expected future costs without delivering corresponding service benefits.

This option would defer, rather than avoid, expenditure and is not consistent with prudent asset management or the least-cost provision of pipeline services. Accordingly, Option 3 is not considered prudent or efficient under the National Gas Rules.

Option 4 – replace the DN250 pipeline

Under this option, APA would replace the existing DN250 pipeline with a new pipeline constructed broadly along the same alignment. This would involve significant capital expenditure associated with construction, land access, approvals and commissioning.

Replacement would address integrity risks; however, it would duplicate capacity that is already efficiently provided by the DN400 pipeline. The DN400 has sufficient capacity and capability to supply all affected customers and represents a lower-risk, lower-cost asset.

As customers would not receive incremental service or reliability benefits beyond those achievable through transition to the DN400, replacement of the DN250 would not represent the least-cost means of meeting current or forecast demand. In addition, construction would introduce avoidable execution, safety and delivery risks, particularly in constrained corridors.

Given the materially higher capital costs and lack of commensurate benefit, this option does not align with the AER's prudency and efficiency tests. Option 4 has therefore been discounted as economically inefficient and not consistent with good industry practice.

3.3.1. Risk assessment

The risk assessment demonstrates that retaining the DN250 in service (Option 1) results in a high inherent risk profile across safety, operational, financial and compliance categories. In contrast, Option 2 reduces these risks to negligible levels by eliminating reliance on an ageing and increasingly inaccessible asset. The primary customer impact risk—loss of supply to the Riverview and Redbank offtakes—is fully mitigated under Option 2 through alternative supply from the DN400. Overall, Option 2 delivers a substantial improvement in residual risk and represents the only option consistent with APA's safety and compliance obligations.

Table 3–1: Risk assessment – DN250 Supply Security

Risk Area	Potential Impact	Option 1: Do nothing		Option 2: Efficient proactive expenditure	
		Likelihood / Impact	Inherent risk rating	Likelihood / Impact	Residual risk rating
Health & Safety	Fatality or injury	Frequent / Minor	Moderate	Rare / Significant	Negligible
Environment	n/a	Unlikely / Minor	Low	n/a	Negligible
Operational	Disruption 1–3 months	Unlikely / Major	High	Remote / Significant	Low
People		Occasional / Major	Moderate	Rare / Significant	Negligible
Compliance	Regulatory breach	Occasional / Major	High	Rare / Significant	Negligible
Reputation & Customer	Adverse media, negative feedback	Unlikely / Major	High	Rare / Significant	Negligible
Financial	Force Majeure and repair costs	Frequent / Significant	High	Rare / Significant	Negligible
Untreated risk			**HIGH**		**LOW**

Option 1

The 'Do Nothing' option carries a high risk that Pipeline Dig Program will be required in inaccessible locations of the asset under and adjacent Ipswich Motorway. Dig up complexity would run in the millions of dollars and require months or years of planning and approvals to complete, if approved to proceed by DTMR.

Option 1 is not financially acceptable, and as such, it is not prudent nor consistent with good practice.

Option 2

Option 2 addresses the need to maintain supply security for customers that are currently supplied via the DN250 to enable safe suspension of that pipeline.

The existing RBP DN250 customers will be supplied from the RBP DN400 pipeline, with dual heating, pressure regulation and backup power supply facilities installed as required.

Option 2 also involves the full decommissioning of all DN250-related surface infrastructure across the remaining compressor station sites, while leaving the DN250 pipework safely in situ. This includes the removal of all DN250 equipment, with shelter structures assessed for potential reuse at other APA locations where practical. By eliminating obsolete equipment, Option 2 ensures the cathodic protection (CP) system can be upgraded to meet the requirements of AS 2832.1 and AS 2885.3, supporting ongoing compliance and reducing long-term corrosion risk. This proactive approach avoids the escalating servicing costs associated with ageing CP units, simplifies site configuration, reduces spares requirements and removes safety and operational risks linked to unused above-ground assets. Option 2 therefore represents the most efficient and prudent course of action, consistent with good industry practice and APA's long-term asset management strategy.

Option 2 is the only credible and practicable option.

3.3.2. Financial assessment

Financial analysis indicates that Option 1 ("Do Nothing") would ultimately cost more than the Phase 2a program due to the scale and complexity of the required dig program, which includes excavations in constrained, high-risk environments with uncertain timelines and significant approval dependencies. Conversely, Option 2 delivers a defined, manageable and efficient expenditure profile, enabling the suspension of the DN250 and avoiding major future integrity costs. Phase 2a is estimated at $7.5 million (Real, June 2026) and represents the most cost-effective means of managing end-of-life risks while maintaining customer supply. Option 2 therefore represents the prudent and economically preferred solution.

Table 3–2: Financial assessment – DN250 Supply Security project ($ Real 30 June 2026)

	Description
Option 1 – Do Nothing	• Requires a large and costly dig program, including 139 excavations in constrained and built-up areas, many under or adjacent to the Ipswich Motorway. • Involves multi-million-dollar works with long approval lead times and significant construction and safety risks. • Leaves the DN250 exposed to ongoing deterioration, including corrosion risks and insufficient CP in some areas. • Cannot support ILI due to the absence of a pig launcher at Ellengrove, limiting inspection capability. • Is not prudent or efficient, and inconsistent with good industry practice due to escalating costs and compliance risks.
Option 2 – Transition Supply to DN400, Suspend DN250 & Decommission Surface assets (Preferred Option)	• Redirects all remaining DN250 customers to the more reliable and higher-capacity DN400 pipeline, ensuring secure and uninterrupted supply. • Eliminates the need for future integrity digs on the DN250 by suspending the pipeline, avoiding substantial multi-million-dollar excavation costs and high-risk works. • Allows APA to decommission redundant DN250 surface assets, reducing long-term maintenance requirements and operational risks. • Addresses inspection constraints (e.g., no pig launcher at Ellengrove) by shifting supply to the DN400, which can be maintained more effectively. • Provides a defined, efficient expenditure profile for removing obsolete equipment and upgrading CP systems. • Avoids high future costs associated with corrosion, emergency repairs and compliance breaches. • Reduces ongoing O&M costs by rationalising six redundant DN250 sites. • Ensures long-term compliance with AS 2832.1 and AS 2885.3, lowering regulatory and safety risk. • Represents the lowest sustainable lifecycle cost, meeting prudency and efficiency requirements under NGR 79. • Represents the only viable and economically justified option, delivering the lowest sustainable cost and aligning with prudent, efficient expenditure under the NGR.

Option 3 - Finalise stage 2a and defer further works.	• Defers, rather than avoids, future expenditure, resulting in higher whole-of-life costs due to ongoing integrity and maintenance requirements. • Retains ageing infrastructure that continues to present increasing safety, compliance and reliability risks. • Requires continued expenditure on inspection, cathodic protection and reactive remediation, despite declining asset utility. • Not consistent with prudent and efficient investment, as it prolongs reliance on a deteriorating asset without delivering incremental service benefit.
Option 4 – replace the DN250 pipeline	• Involves substantial capital expenditure (~$300 million) to construct a replacement pipeline duplicating existing DN400 capacity. • Delivers limited incremental benefit to customers, as demand can already be met by the DN400. • Introduces significant construction, delivery and approval risks in constrained corridors. • Does not represent the least-cost option for meeting service requirements, and is therefore inconsistent with NGR prudency and efficiency criteria.

3.4. Proposed costs for FY28-FY32

The total forecast capital expenditure for **DN250 Supply Security Project** over the FY28–FY32 access arrangement period is **$12.889 million (Real $2026)**. This forecast represents the cost of the works required to transition remaining DN250 customers to the DN400 pipeline, decommissioning redundant DN250 surface facilities, and completing associated works required to support the safe suspension of the DN250 pipeline following customer transition to the DN400. The expenditure has been developed on a **prudent, efficient, and evidence-based basis**, drawing on detailed scope definition, site-specific design requirements, historical delivery experience for comparable works, and current market-tested contractor rates under APA's national vendor arrangements. The timing and scale of the forecast reflect the need to mitigate near-term integrity and supply-security risks associated with continued DN250 operation while avoiding the significantly higher costs and delivery risks of extensive integrity dig programs. The proposed expenditure enables completion of an essential enabling phase of the DN250 Supply Security Program and represents the **lowest sustainable cost** approach to maintaining safe, reliable supply, consistent with the capital expenditure criteria in **NGR Rule 79**.

Table 3–3: Estimated annual cost DN250 Supply Security Project ($'000s Real 2026-27)

Description	FY28	FY29	FY30	FY31	FY32	Total
DN250 Supply Security - Phase 2a	3,588	4,316	-	-	-	**7,904**
DN250 Suspension - Phase 3	1,207	1,210	1,171	1,155	2,274	**7,016**
FY Total	**4,795**	**5,525**	**1,171**	**1,155**	**2,274**	**14,920**

4. AC Mitigation

4.1. Project objective and scope

The objective of the AC Mitigation program is to assess and mitigate AC-induced corrosion risks along the DN250 pipeline between Oakey and Bellbird Park, where proximity to high-voltage transmission and distribution infrastructure has resulted in elevated steady-state induced voltages. These voltages pose a risk of AC corrosion, personnel safety hazards and potential interference with cathodic protection (CP) systems on nearby foreign structures. The program includes AC current-density testing, evaluation of CP performance, and implementation of targeted mitigation measures to ensure compliance with relevant standards and regulatory requirements.

4.2. Background

The DN250 pipeline corridor runs parallel to multiple high-voltage power lines, resulting in steady-state AC induction and elevated touch and step potentials in some locations. These conditions were confirmed through APA's 2023 AS 4853 Level 3 Electrical Hazard Assessment, which identified locations experiencing load-flow-induced (LFI) voltage and earth-potential-rise (EPR) impacts. As the DN250 is being progressively suspended from normal operation, changes to CP inspection frequency and criteria are also required. The AC Mitigation program will therefore validate AC corrosion susceptibility through current-density testing at high-voltage areas identified in CP surveys and will re-assess the applicability of the 100 mV depolarisation criterion for suspended assets.

4.3. Assessment of options

The options considered for the access arrangement period are:

- Option 1: Do nothing
- Option 2: Option 2 – Targeted AC Mitigation (Preferred Option)
- Option 3: Maximum Mitigation

4.3.1. Risk assessment

Risk assessment results indicate that AC-induced corrosion, safety hazards, and regulatory non-compliance remain at Extreme risk levels under Option 1. Both Options 2 and 3 reduce these risks to Low, though Option 2 does so more efficiently through targeted intervention. Option 2 therefore provides the optimal risk-benefit balance.

Table 5–1: Risk assessment – AC Mitigation

Risk Area	Potential Impact	Option 1 :		Option 2:	
		Likelihood / Impact	Inherent risk rating	Likelihood / Impact	Risk rating
Health & Safety	Fatality or injury	Unlikely / Major	High	Rare / Major	Low
Environment	n/a	n/a	n/a	n/a	n/a
Operational	Disruption 1-3 months	Unlikely / Major	High	Rare / Major	Low
People	n/a		n/a	n/a	n/a

Compliance	Regulatory breach	Frequent / Minor	Moderate	Remote / Minor	Negligible
Reputation & Customer	Adverse media, negative feedback	Unlikely / Minor	Low	Rare / Minimal	Negligible
Financial	n/a	n/a	n/a	n/a	n/a
Untreated risk			**HIGH**		**LOW**

Option 1 - Do Nothing

This option would leave AC voltage levels uncontrolled, significantly increasing the risk of AC-induced corrosion, CP interference, and electric-shock hazards for field personnel. It would also lead to non-compliance with AS 2832.1 and other regulatory requirements. Deferred expenditure under this option would be outweighed by the very high cost of future corrosion repairs and associated safety, environmental and operational impacts. Option 1 is therefore not prudent, nor acceptable under good industry practice.

Option 2 - Targeted AC Mitigation (Preferred Option)

Option 2 involves implementing mitigation measures only in locations where testing identifies AC voltages or current densities above recommended thresholds. This targeted approach ensures compliance with AS 2832.1, AS 2885.3 and AS 3000, while minimising CP interference and enabling registration of the CP system with the Electrical Safety Office (ESO). Current output will be reduced where appropriate once updated depolarisation criteria are approved. Option 2 delivers the lowest-cost effective mitigation strategy and balances risk, practicality, and efficiency.

Option 3 - Maximum Mitigation

Option 3 addresses the same risks as Option 2 but applies mitigation across the full length of the DN250 corridor. While this option is highly effective, it carries significantly higher upfront capital costs and presents greater execution complexity. It is therefore less efficient than Option 2.

4.3.2. Financial assessment

The financial assessment shows that maintaining the current state without mitigation would expose the pipeline to increasing corrosion risk, leading to potentially substantial future repair costs and regulatory non-compliance. Proactive mitigation represents a more cost-effective approach, as targeted investment in AC control measures reduces the likelihood of expensive corrective works and operational disruptions. While more comprehensive mitigation options are available, these carry higher upfront expenditure with limited incremental benefit. The preferred option therefore balances cost and risk by implementing mitigation only where testing confirms elevated AC interference, ensuring prudent and efficient use of capital consistent with the National Gas Rules.

Table 5–2: Financial assessment – AC Mitigation

	Description
Option 1 - Do Nothing	• Leaves the DN250 exposed to progressive corrosion due to ageing CP units and coating defects, increasing the likelihood of future failures. • Risks non-compliance with AS 2832.1 and the RBP pipeline licence as CP systems deteriorate and fail to provide adequate protection.

	• Avoids short-term expenditure but results in significantly higher long-term costs due to corrective corrosion repairs and potential asset failure. • Considered not technically acceptable, nor prudent or consistent with good industry practice.
Option 2 - Targeted AC Mitigation (Preferred Option)	• Implements AC mitigation only at locations where testing identifies elevated AC voltages or current densities, ensuring a risk-based and efficient approach. • Ensures compliance with AS 2832.1, AS 2885.3 and AS 3000, while reducing CP interference and supporting ESO registration of the CP system. • Allows for adjustment of CP output once revised depolarisation criteria are approved, improving system stability and minimising interference with neighbouring infrastructure. • Provides a cost-effective balance between risk reduction and capital investment, avoiding the higher expenditure required under maximum-mitigation scenarios. • Reduces safety, operational and financial risks to low levels, delivering the optimal risk-benefit outcome.
Option 3 - Maximum Mitigation	• Applies comprehensive AC mitigation across the full length of the DN250 corridor, not just high-risk locations. • Provides the highest level of AC-corrosion protection, but delivers only marginal added benefit compared with targeted mitigation. • Involves substantially higher upfront capital expenditure and greater execution complexity than Option 2. • Although technically effective, it is less efficient and does not represent the lowest-cost way to achieve compliance and risk reduction.

The preferred option that appropriately balances costs and risks is Option 2, mitigating AC current density at locations to be determined from AC assessment report and focusing on mitigation only at necessary section with very high AC Voltage level.

4.4. Proposed cost for FY28-FY32

The AC Mitigation program is planned to be delivered progressively across the access arrangement period, with works carried out by a combination of APA field personnel and specialist contractors as required. Consistent with the previous access arrangement cycle, funding is proposed to support mitigation at three identified sites along the DN250 corridor. Annual expenditure is evenly allocated across FY28–FY32 to provide a stable, efficient delivery profile and to align mitigation activity with field resource availability. The total forecast expenditure for the period is **$1.45 million**, with funds allocated each financial year for detailed design, installation of mitigation systems and post-installation verification activities.

Table 5–3: Estimated yearly cost AC Mitigation ($'000s Real 2026-27)

Description	FY28	FY29	FY30	FY31	FY32	Total
DN250 AC Mitigation (Oakey to Bellbird Park)	288	289	290	291	292	1,449

Environmental Projects Business Case

Roma to Brisbane Gas Pipeline Access Arrangement 2028–32

29 May 2026

Contents

1. Overview

Number/ identifier	A-3_Environment
Description of Issue/ Project	Flooding and ongoing creek bed erosion at the Gowrie Creek crossing have resulted in loss of pipeline cover and exposure of the RBP400 below the waterline. Hydraulic turbulence, exacerbated by an upstream weir structure, has created a credible risk of pipeline undermining, free-spanning and debris impact. Temporary flood protection measures are currently in place but are subject to regulatory expiry and do not provide a permanent, compliant solution. The project seeks to implement permanent remediation to stabilise the crossing and mitigate integrity and safety risks in accordance with AS 2885.
Options considered	**Option 1 — Do Nothing *(Not prudent or compliant)*** Only minimal integrity activity is performed while allowing environmental degradation to continue. This results in increasing likelihood of pipeline exposure, instability, and failure. The option is inconsistent with AS 2885, creates safety and environmental risks, and is not compliant with NGR 79. **Option 2 — Targeted Environmental Remediation (Preferred)** This option implements risk based environmental mitigation activities such as flood protection, erosion control, ground stabilisation, and cover restoration at identified high risk locations. It reduces risk to ALARP, maintains pipeline integrity, and represents prudent and efficient expenditure. **Option 3 — Replace Affected Pipeline Sections via HDD (Fall back Option)** Large-scale pipeline replacement using Horizontal Directional Drilling is technically feasible and removes exposure to future erosion but is significantly more expensive than targeted remediation. It is only required where external approvals prevent implementation of Option 2
Proposed Solution	The preferred solution comprises targeted environmental risk mitigation works, including flood protection, stabilisation activities, and associated geotechnical and civil works to maintain cover and support. This delivers a cost effective and efficient way to reduce environmental threats to ALARP and ensure the ongoing safety and integrity of the RBP.
Estimated Cost	**$10.4 million** (upper bound estimate based on HDD, noting actual expenditure will be lower if the preferred Option 2 solution is permitted)
Relevant standards	The proposed activities align with the following standards and obligations: • **AS 2885.3 – Pipelines: Gas and Liquid Petroleum – Operations and Maintenance** • **RBP Pipeline Licence** and associated safety and integrity obligations
Stakeholder Engagement	• Scope discussed during RBP Access Arrangement Stakeholder Meetings #3 (25/11/2025); #4 (10/02/2026); and #5 (31/03/2026)

Consistency with National Gas Rules (NGR)	The proposed expenditure satisfies NGR 79 because it: • is **necessary** to maintain and improve the safety and integrity of pipeline services (NGR 79(2)(c)(i)–(ii)); • is **prudent and efficient**, representing expenditure a reasonable service provider would incur acting in accordance with good industry practice to achieve the lowest sustainable cost (NGR 79(1)(a)); • addresses known and emerging environmental risks that could lead to failure if left untreated; • maintains compliance with AS 2885 and relevant legislation by ensuring risks are reduced to ALARP.

2. Program details

2.1. Background

The Roma to Brisbane Pipeline (RBP) requires ongoing stay in business capital expenditure to ensure it remains fit for purpose over its operating life. While the pipeline is typically buried, environmental factors — including flood behaviour, river morphology, geotechnical instability, erosion, and weather driven ground movement — can reduce pipeline cover or compromise its stability. These issues are identified through:

- routine patrols and inspections,
- performance monitoring,
- geotechnical and hydrological assessments, and
- observations following extreme weather events.

For the 2028–32 Access Arrangement period, one priority remediation project has been identified:

8. **Gowrie Creek Flood Protection** – addressing loss of cover and erosion caused by flood induced creek bed changes.

The Environmental Program therefore focuses on locations where changing natural conditions pose a direct integrity threat, ensuring the RBP continues to operate safely and reliably under evolving environmental conditions.

A recent flood event at the RBP400 Gowrie Creek crossing caused severe creek bed erosion. Turbulence generated by a manmade upstream weir accelerated scouring, resulting in the pipeline becoming exposed below the waterline.

A temporary sandbag protection system is currently in place to reduce risk of impact or strain. This temporary measure has been approved only on an interim basis by the Department of Agriculture and Fisheries, with conditions requiring annual re-approval and an expiry in December 2028.

Two long-term remediation options have been identified:

Concrete mattress or similar engineered creek bed stabilisation

- Armours the creek bed and dissipates hydraulic energy.
- Requires design approval from the Department of Agriculture and Fisheries.
- Technical details & constructability is still being confirmed.

Horizontal Directional Drilling (HDD)

- Realigns the pipeline at a deeper elevation beneath the creek.
- Technically mature but more expensive due to topography and proximity to the Warrego Highway.

Without long-term remediation, continued erosion is expected to progress to pipeline undermining and free spanning. In this condition, debris impact and Vortex Induced Vibration (VIV) can initiate fatigue cracking and eventual rupture — a failure mechanism previously observed on similar pipelines (e.g., Young–Lithgow pipeline at Bathurst in 2022).

2.2. Project objective and scope

The objective of this project is to protect the RBP400 pipeline at the Gowrie Creek crossing, where recent changes in creek morphology and local geology have resulted in significant scouring and loss of cover. Without intervention, continued degradation presents a credible risk of:

- pipeline undermining and free spanning,
- exposure below the waterline,

- mechanical damage from debris impact,
- strain and fatigue from vortex induced vibration (VIV), and
- potential loss of containment.

If untreated, the worst-case consequence is an estimated outage of at least 4 weeks, affecting all residential and industrial customers in Brisbane and surrounding regions with an interim solution to restore gas flow before a more permanent emergency solution is undertaken.

The scope includes delivering a long-term, permanent flood protection solution to maintain cover, stabilise the creek bed, and prevent exposure and mechanical damage.

The forecast cost reflects the upperbound HDD (Horizontal Directional Drilling) option based on tendered received in 202X, as this may be required if approval constraints from the Department of Main Roads (TMR), owner of the adjacent bridge asset, restrict the preferred lower cost solution. Should the preferred option be permitted, actual expenditure will be materially lower.

2.3. Assessment of options

Three high-level investment approaches have been considered for the environmental program.

Option 1 – Do Nothing (Accept Non-conformance)

Under this approach, APA would undertake only minimal integrity activity and allow environmental degradation such as erosion, loss of cover, and ground instability to continue unmitigated. This would lead to:

- increasing probability of pipeline exposure,
- undermining or free spanning of the pipeline,
- higher likelihood of fatigue, rupture, or mechanical damage,
- unplanned outages with significant safety, environmental, and supply impacts, and
- potential non-compliance with AS 2885 and pipeline licence obligations.

This option is not prudent, not compliant, and inconsistent with NGR 79, and is therefore rejected.

Option 2 – Planned Proactive Remediation (Preferred)

This approach involves timely intervention to maintain pipeline stability and cover, addressing environmental threats before they escalate. Activities may include:

- flood protection works,
- ground reinforcement and stabilisation,
- erosion control, and
- other targeted environmental remediation.

This option:

- reduces risks to ALARP in accordance with AS 2885,
- supports predictable and efficient expenditure,
- avoids high-cost emergency remediation,
- maintains compliance with regulatory and licence obligations, and
- prevents operational disruptions resulting from environmental failures.

Given the high cost of reactive works and the accelerating nature of environmental degradation, **Option 2 is the prudent, efficient, and preferred approach**

Option 3 – Replace affected pipeline sections

Pipeline replacement via Horizontal Directional Drilling (HDD) is technically mature and was selected as a preferred option during internal assessments in the current regulatory period. However tender responses raised constructability constraints were raised that required a much longer more complex drill than initially anticipated and a resulting price approximately 3 time higher than anticipated. This solution would resolve environmental risks by installing deeper infrastructure. However:

1. costs are significantly higher than targeted remediation,
2. the method requires complex in-service welding, live tie-ins, and stoppings,
3. the site presents interactions with public utilities and constrained land corridors, and
4. the option does not reflect prudent or efficient expenditure unless mandated by external approval requirements.

This option is considered only as a fallback solution where engineered environmental remediation (Option 2) is not permitted

2.3.1. Inherent Risk assessment

Loss of pipeline cover, exposure below the waterline and undermining give rise to recognised integrity threats under AS 2885. These conditions alter the pipeline's support environment and can directly lead to safety hazards if left unmitigated.

As erosion or scour removes surrounding soil, sections of pipe may become partially or fully unsupported. This introduces bending stresses that are not present in a continuously supported pipeline and can exceed allowable limits, particularly during high-flow or flood conditions. Where exposure persists, the risk of fatigue damage increases due to cyclic loading, hydrodynamic forces and vortex-induced vibration.

Exposure also increases vulnerability to external mechanical damage, including debris impact during flood events, and removes the restraining effects of soil that limit pipe movement under thermal and pressure-related loads. These factors can concentrate stress at span shoulders and transition points, increasing the likelihood of cracking or loss of containment over time.

Under Option 1 (do nothing), ongoing environmental degradation would therefore result in a progressively increasing probability of structural failure, with potentially severe consequences including gas release, ignition, fire and harm to the public or personnel. This risk profile is inconsistent with the obligation under AS 2885 to reduce risks to ALARP, and with the expectations of a prudent service provider under NGR 79, given that the hazards are foreseeable and mitigation options are available.

Conversely, the remediation works proposed under Option 2 address the root causes of these safety risks by maintaining pipeline support, restoring cover and protecting the asset from external loading and interference. This preserves the pipeline's original design assumptions, materially reduces the likelihood of failure, and explains the reduction from High inherent risk under Option 1 to Low or Negligible residual risk following mitigation.

Table 2–1: Inherent risk rating of the CP business case

Risk Area	Potential Impact	Option 1: Do nothing		Option 2: Efficient proactive expenditure	
		Likelihood / Impact	Inherent risk rating	Likelihood / Impact	Residual risk rating
Health & Safety	Fatality or injury	Remote / Major	Moderate	Rare / Minor	Negligible

Environment	Environmental Harm	Unlikely / Minor	Low	Remote / Significant	Low
Operational	Disruption 1–3 months	Unlikely / Major	High	Remote / Significant	Low
People	Impact capability of staff	Unlikely / Significant	Moderate	Remote / Minor	Negligible
Compliance	Regulatory breach	Unlikely / Significant	Moderate	Remote / Significant	Low
Reputation & Customer	Adverse media, negative feedback	Unlikely / Minor	Low	Remote / Minor	Negligible
Financial	Force Majeure and repair costs	Unlikely / Minor	Low	Remote / Minor	Negligible
Untreated risk			**HIGH**		**LOW**

Financial assessment

A qualitative financial assessment compared the lifecycle cost implications of Options 1 and 2:

Option 1 – Do Nothing (Accept Non-conformance)

- Results in unpredictable, reactive expenditure.
- Requires urgent mobilisation at premium rates.
- Leads to increasing scale and cost of remediation as degradation accelerates.
- Elevates probability of high-impact failures, outages, and regulatory non-compliance.
- Does not represent prudent or efficient expenditure.

Option 2 – Planned Proactive Remediation (Preferred)

- Enables predictable and stable expenditure across the 2028–32 period.
- Allows efficient bundling of works and optimal resource use.
- Avoids expensive emergency repairs and degradation-driven failures.
- Reduces the likelihood of operational disruption.
- Represents the lowest sustainable lifecycle cost.

The financial assessment supports Option 2 as the prudent and efficient investment option

Table 2–2: Financial assessment of the Environment business case

	Commentary
Option 1: Accept non-conformance with regulations and asset failure	• Risks complete loss of gas supply to all SEQ customers including essential services such as hospitals for extended period. • Expenditure becomes unpredictable and reactive, driven by failure events. • Emergency works are more expensive, with efficiency losses from urgent mobilisation. • As degradation progresses, scope and cost of rectification escalate. • Increased failures can exceed internal resource capacity, requiring contractors at premium rates. • Short-term avoided costs are more than offset by long-term repair costs, regulatory penalties, and reputational impacts. • Not aligned with efficient lifecycle management; results in higher total cost over time.

Option 2: Planned Proactive Remediation	• Enables bundling of works with other activities, improving resource and cost efficiency. • Supports a stable, predictable expenditure profile over the Access Arrangement period. • Avoids costly emergency repair campaigns by intervening before conditions worsen. • Prevents asset degradation reaching failure, reducing overall lifecycle expenditure. • Aligns with good industry practice, providing the lowest sustainable long-term cost.

The risk and financial assessments above support the preferred option (option 2) as appropriately balancing costs and risks.

2.4. Proposed costs for FY28-FY32

The preferred solution for managing the Gowrie Creek integrity threat is the Concrete Mattress or similar engineered protection system (Option 2), which provides a long-term, cost-effective remediation outcome at a materially lower cost than the Horizontal Directional Drill (HDD) alternative.

However, implementation of Option 2 is subject to external approvals and asset ownership constraints. The section of Gowrie Creek where the pipeline is at risk is spanned by a bridge owned by the Department of Main Roads (TMR). Preliminary engagement indicates that TMR's requirements for works within or adjacent to their bridge assets may limit or prevent construction of an in-situ creek bed stabilisation solution. In the event that TMR does not permit the installation of a concrete mattress or similar structure, APA may be required to pursue Option 3 – HDD replacement as the only feasible permanent mitigation measure.

Accordingly, while Option 2 remains the preferred and lowest cost option, APA must account for the possibility that Option 3 will be required to ensure compliance with AS 2885 and to reduce risks to ALARP should regulatory or ownership constraints restrict implementation of the lower cost solution.

Given this uncertainty, the Access Arrangement forecast reflects the upperbound cost associated with HDD installation to ensure that APA can deliver a compliant, permanent remediation outcome under either scenario. Should TMR approval enable Option 2 to proceed, APA will implement the lower cost solution and actual expenditure will be materially lower than the provision included in the forecast.

Table 3-3 below therefore presents the total estimated cost for delivery of the Gowrie Creek Flood Protection works in FY28 based on the HDD option, acknowledging that the final cost will be reduced if Option 2 is approved and implemented.

Regulatory Treatment and Prudency Considerations

The inclusion of the HDD cost in the capital forecast reflects a prudent and efficient approach under NGR 79. While Option 2 remains, APAs preferred and lowest cost solution, external ownership and approval constraints associated with the TMR bridge may necessitate the higher cost HDD option. As the service provider must ensure the pipeline remains compliant with AS 2885 and risks are reduced to ALARP, the Access Arrangement forecast must accommodate the foreseeable highest cost compliant option. This ensures APA can deliver a permanent, safety critical remediation even if Option 2 is not permitted. If TMR approval allows Option 2 to proceed, APA will adopt that solution and actual capital expenditure will be materially below the forecast allowance, consistent with efficient lifecycle cost management.

Table 3–3: Estimated annual cost Gowrie Creek Flood Protection ($'000s Real 30 June 2026)

Description	FY28	FY29	FY30	FY31	FY32	Total
Gowrie Creek flood protection	10,380	-	-	-	-	10,380

Note: *The cost shown reflects the HDD option (Option 3) to ensure adequate provision should TMR requirements prevent implementation of the lower cost concrete mattress solution (Option 2). APA will pursue Option 2 where permissible, and actual incurred costs will be lower if approval is granted.*

2.5. Consistency with the National Gas Rules and other regulations

The Environmental Program meets NGR 79 because the expenditure is necessary to avoid subsequent failure of the pipeline, it:

- is necessary to maintain and improve pipeline safety and integrity (NGR 79(2)(c)(i)–(ii)),
- aligns with AS 2885 requirements to manage environmental threats to ALARP,
- represents efficient and prudent expenditure to minimise lifecycle cost, and
- avoids higher future expenditure associated with reactive remediation or asset failure.

Overall, the program supports the ongoing safe, reliable, and secure operation of the RBP.

Instruments and Control Business Case

Roma to Brisbane Gas Pipeline Access Arrangement 2028–32

29 May 2026

Contents

3. Overview

Number/ identifier	A-4_Gas Instruments
Description of Issue/ Project	This business case covers the replacement and upgrade of metering and instrumentation assets across the Roma to Brisbane Pipeline (RBP) above-ground facilities. These assets provide essential measurement, gas quality analysis, and operational control functions required to ensure the safe, reliable and compliant operation of the pipeline. The program encompasses the renewal of Gas Chromatographs (GCs), Moisture Analysers, Turbine Meters, and Flow Computers, which have reached or are approaching obsolescence and increasing failure risk.
Options considered	**Option 1 – Do Nothing** Under this option, obsolete or failing instrumentation is left in service until end-of-life failure occurs. This approach increases the risk of inaccurate gas quality measurement, non-compliance with gas specification and energy measurement obligations, unplanned outages, higher maintenance costs, and increased operational inefficiencies. **Option 2 – Replace Obsolete Metering & Instrumentation Components (Preferred)** This option involves planned and proactive replacement of ageing and unsupported equipment. It ensures ongoing measurement accuracy, maintains compliance with regulatory and contractual requirements, and minimises the risk of operational disruption. **Note:** For the ControlWave Micro RTU & Flow Computers upgrade, a third option — Maintain Current Fleet with Stockpiled Spares — was also considered. This option provides only short-term risk mitigation, does not address cybersecurity and long-term support risks (post-2030), and was not preferred.
Proposed Solution	The preferred solution (Option 2) includes: • Replacement of Gas Chromatographs and Moisture Analysers at Scotia and Woodroyd sites • Replacement of Gas Chromatographs only at Ellengrove and Brightview • Replacement of Turbine Meters at Toowoomba and Redbank Plains, upgrading to Coriolis meters for improved reliability and diagnostic capability • Progressive upgrades of RTUs & Flow Computers across multiple sites as existing ControlWave MRTUs & Flow Computers as units approach obsolescence This program of coordinated replacements will reduce operational risk, improve reliability of metering systems, and maintain compliance with measurement and gas quality obligations.
Estimated Cost	$3.872 million

Relevant standards	• AS 2885.3 Pipelines: Gas and Liquid Petroleum Operations and Maintenance. • RBP Pipeline Licence
Stakeholder Engagement	• Scope discussed during RBP Access Arrangement Stakeholder Meetings #3 (25/11/2025); #4 (10/02/2026); and #5 (31/03/2026)
Consistency with National Gas Rules (NGR)	As it replaces obsolete equipment that can not guarantee security and risk malfunction the proposed expenditure meets the capital expenditure criteria in NGR 79, because it: • Is necessary to maintain the accuracy, safety and integrity of pipeline services (NGR 79(2)(c)(i)–(ii)) • Is prudent and efficient, avoiding the higher costs and operational impacts associated with reactive replacement of critical measurement equipment (NGR 79(1)(a)) • Reflects good industry practice, addressing foreseeable obsolescence and reliability risks before they cause service disruption • Ensures ongoing compliance with gas quality and energy measurement requirements under the RBP Pipeline Licence and associated regulations

4. Program details

4.1. Background

Accurate gas measurement is fundamental to the safe, reliable, and compliant operation of the Roma to Brisbane Pipeline (RBP). Metering and analytical instruments—including Gas Chromatographs (GCs), Moisture Analysers, turbine meters, and flow computers—provide the data required to determine gas composition, heating value, and energy quantities for custody transfer and billing purposes.

For customers connected to the RBP, these instruments directly underpin:

- the accurate calculation of energy delivered;
- billing and settlement under contractual arrangements; and
- confidence that gas quality specifications are being met at all times.

If critical measurement or analytical instruments fail or degrade beyond acceptable accuracy, APA's ability to determine gas energy content and moisture compliance is compromised. In such circumstances, energy quantities may need to be estimated or substituted, increasing the risk of billing inaccuracies, customer disputes, and loss of confidence in measurement outcomes.

Many of the instruments currently installed on the RBP are more than 20 years old, are obsolete and/or approaching end of manufacturer support. OEMs have withdrawn spare part supply, firmware updates, and technical support, increasing the likelihood of failure and extending restoration times when faults occur. Lead times for replacement equipment now commonly exceed 30–42 weeks, making reactive replacement impractical for assets that perform continuous billing-critical functions.

From a customer perspective, failure of these instruments can result in:

- delays or disputes in billing and settlement;
- increased reliance on estimated energy values;
- potential non-compliance with contractual measurement and gas quality requirements; and
- reduced transparency and confidence in pipeline operations.

These risks are particularly significant at custody-transfer and receipt/ delivery points, where measurement accuracy is essential to accurate, fair and equitable customer outcomes.

The Gas Instruments program addresses these risks by proactively replacing ageing and unsupported equipment before failure occurs. This ensures measurement integrity is maintained, customer billing remains accurate and transparent, and APA continues to meet its regulatory, contractual, and licence obligations. Proactive renewal of these assets supports both customer confidence and the lowest sustainable cost of service provision, by avoiding prolonged outages, emergency works, and inefficient reactive expenditure.

4.2. Assessment of options

Two high-level options were considered for the Gas Instruments program:

Option 1 – Do Nothing (Run to Failure)

Under this option, obsolete instruments would remain in service until they fail. This approach results in:

- Increasing risk of extended outages due to long equipment lead times (30–42 weeks typical for GCs and Moisture Analysers)
- Reduced accuracy of gas quality and energy measurement
- Higher operational costs from frequent troubleshooting, ad-hoc repairs, and sourcing obsolete spare parts from second hand suppliers and web markets such as Ebay.

- Increased likelihood of regulatory and contractual non-compliance
- Inefficient expenditure due to emergency mobilisation and unplanned corrective work

Option 1 exposes APA and customers to material operational, compliance, and financial risks and is not consistent with prudent asset management. Additionally, given the age profile of the equipment much of the equipment would likely be replaced at failure over the next one-two regulatory periods anyway in a reactive manor.

Option 2 – Planned and Proactive Replacement (Preferred)

Option 2 involves replacement of obsolete meters and analysers at planned intervals based on equipment criticality, asset condition, and operational performance.

This approach:

- Ensures continued compliance with energy measurement and gas specification requirements
- Reduces the likelihood of in-service failure and associated service disruptions
- Allows efficient planning, resource allocation, and coordination with other site works
- Enables standardisation of equipment fleets and more efficient spare-parts management
- Reduces lifecycle costs by avoiding high-cost reactive repairs

The option delivers predictable expenditure profiles and lowers overall system risk.

Inherent Risk assessment

If no action is taken under Option 1, the risk of measurement errors, specification non-compliance, extended outages, and operational disruption increases significantly as equipment ages. The inherent risk assessment undertaken across all gas instrument asset classes shows **High** untreated risk in safety, operational, compliance, reputation, and financial categories.

Under Option 2, risks are reduced to **Low or Negligible**, as proactive replacement removes obsolescence driven failure modes and ensures equipment remains accurate, reliable, and supported by manufacturers.

This demonstrates that Option 2 represents the prudent and efficient risk mitigating approach consistent with AS 2885 expectations and APA's Enterprise Risk Framework.

Table 2–1: Inherent risk rating of the Gas Instruments business case

Risk Area	Potential Impact	Option 1 :		Option 2:	
		Likelihood / Impact	Inherent risk rating	Likelihood / Impact	Risk rating
Health & Safety	n/a		n/a	n/a	n/a
Environment	n/a		n/a	n/a	n/a
Operational	Disruption 1-3 months	Frequent / Significant	High	Remote / Significant	Low
People	n/a		n/a	n/a	n/a
Compliance	Regulatory breach	Frequent / Minor	Moderate	Remote / Minor	Negligible
Reputation & Customer	n/a		n/a	n/a	n/a

Financial	Revenue <$1M	Impact	Frequent / Minimal	Low	Remote / Minimal	Negligible
Untreated risk				**HIGH**		**LOW**

Financial assessment

As the timing and extent of failures under a run-to-failure approach cannot be forecast with sufficient certainty, a meaningful Net Present Value comparison is not feasible for Option 1. However, the industry practiceclearly demonstrates that reactive failure driven replacement leads to materially higher lifecycle costs, increased volatility in expenditure, and heightened exposure to regulatory and commercial risks.

Conversely, the preferred option—planned and proactive replacement—provides a stable and efficient expenditure profile, reduces the need for costly emergency mobilisation, and avoids the premium pricing associated with procuring obsolete equipment and undertaking unplanned works. This option reflects prudent asset management and is consistent with good industry practice and the capital expenditure criteria in NGR 79.

Table 2-2 provides a summary of the financial implications of each option.

Table 2–2: Options assessment of the Gas Instruments business case for proposed replacement Gas Chromatographs, Moisture Analysers, Turbine Meters and Flow Control Computers.

	Commentary
Option 1: Do Nothing (Run to Failure)	• Unplanned, reactive replacements lead to inefficient costs, including higher labour, contractor standby, and mobilisation expenses. • Expenditure becomes increasingly lumpy and unpredictable as asset failures cluster with advancing age and obsolescence. • Increased risk of emergency works during periods of high operational demand, with limited ability to schedule efficient resource utilisation. • Premium pricing for obsolete assets and components, as OEM support diminishes and spare parts become scarce. • Heightened risk of regulatory or contractual non-compliance, potentially leading to material financial penalties and customer disputes. • Significant indirect financial impacts, including increased operational disruption, prolonged outages due to long supply lead times (30–42 weeks), and reputational damage arising from measurement inaccuracies. • Any short-term deferral of capital outlay is fully offset—and exceeded—by higher reactive repair costs and risk-related financial exposure.
Option 2: Planned and Proactive Replacement (Preferred)	• Coordinated replacement with other scheduled site works enables efficient bundling of labour, mobilisation, and commissioning activities. • Stable, predictable expenditure profile over the 2028–32 period, supporting prudent capital planning and smoothing the investment cycle. • Avoids the elevated costs of emergency mobilisation, overtime labour, and premium-priced legacy components. • Optimises lifecycle cost outcomes, reducing overall asset stewardship cost by replacing equipment before failure modes escalate. • Enables standardisation across metering and instrumentation assets, improving long-term maintainability and reducing inventory and training costs.

	• Supports compliance with measurement, gas quality and licence obligations, effectively avoiding the financial and non-financial risks inherent in the run-to-failure approach. • Ensures continuity of accurate billing and gas specification monitoring, reducing the likelihood of commercial disputes or customer impacts.

The risk and financial assessments above support the preferred option (option 2) as appropriately balancing costs and risks.

4.3. Consistency with the National Gas Rules and other regulations

The Gas Instruments program complies with the capital expenditure criteria in **NGR 79**, as the prevention of failure of the gas instruments:

- Is necessary to maintain the safety, integrity, and reliability of pipeline services;
- avoid foreseeable non-compliance with gas quality and measurement obligations;
- would be incurred by a prudent operator, given the equipment's age, obsolescence, and criticality;
- represent the lowest sustainable lifecycle cost, avoiding inefficient reactive expenditure;
- align with good industry practice, including proactive management of obsolescence and standardisation of metering systems;
- Support compliance with the RBP Pipeline Licence, relevant gas measurement requirements, and AS 2885.3.

4.4. Proposed costs for FY28-FY32

The total capital cost for the Gas Instruments program is **$3.87 million (Real $2026)** across FY28–FY32.

Costs include the planned replacement of:

- GCs & Moisture Analysers at Woodroyd and Scotia
- GCs at Ellengrove and Brightview
- Turbine Meters (upgraded to Coriolis meters) at Toowoomba & Redbank Plains
- Flow Computer upgrades across multiple sites
- Detailed annual expenditure by asset group is set out in Sections 3–6.

The proposed costs reflect efficient planning, bundling of works, and use of APA resources supported by specialist vendors where required.

Table 2–3 Total cost for Gas Instruments business cases ($'000s Real 30 June 2026)

Description	FY28	FY29	FY30	FY31	FY32	Total
Woodroyd - GC & Moisture Analyser	461	-	-	-	-	**461**
Scotia - GC & Moisture Analyser	-	462	-	-	-	**462**
Ellengrove GC Upgrade	-	-	290	-	-	**290**
Brightview GC Upgrade	-	-	-	233	-	**233**
Redbank - Turbine Meter Upgrade	-	-	-	-	163	**163**
Toowoomba - Turbine Meter Upgrade	-	-	-	-	233	**233**
Flow computers upgrade (each site where we have obsolete Flow Computers Controlwave Micro)	404	404	406	407	408	**2,029**
FY Total	**865**	**750**	**600**	**550**	**690**	**3,872**

5. GC & Moisture Analyser replacements

5.1. Project objective and scope

The objective of this project is to ensure the continued accurate measurement of gas composition and moisture content at critical Roma to Brisbane Pipeline (RBP) metering stations through the proactive replacement of obsolete Gas Chromatographs (GCs) and Moisture Analysers.

Gas Chromatographs provide the gas composition and heating value data used to calculate energy quantities for billing, custody transfer, and contractual settlement. Moisture Analysers confirm compliance with gas quality specifications and support the validity of GC calculations. Together, these instruments form the primary basis for determining the billable energy delivered to customers.

If the GC or associated analytical instruments fail, it is no longer possible to reliably determine gas composition or heating value. In such circumstances:

- energy quantities cannot be calculated with the required accuracy;
- customer billing would be based on estimates or substituted data; and
- APA would be exposed to increased risk of billing inaccuracies, commercial disputes, and non-compliance with measurement and licence obligations.

Given the critical role these instruments play in energy calculation and revenue settlement, their failure represents not only an operational risk, but a material commercial and regulatory risk to both APA and pipeline users.

The project scope includes the planned replacement of obsolete GCs and Moisture Analysers at identified sites, including procurement, installation, configuration, commissioning, and integration with existing metering, SCADA, and flow computer systems. Works will be delivered in a coordinated manner to minimise outage duration and ensure continuity of compliant gas measurement and billing capability.

5.2. Background

GCs and Moisture Analysers across the RBP were installed more than 20 years ago and have continued to operate with OEM support until recently. With advancements in technology, manufacturers have released new instrument models and progressively discontinued maintenance of older generations.

As a result:

- OEM support has ceased, including spare parts and firmware updates
- Operational spares are increasingly difficult to obtain and command premium prices
- Existing units are suffering measurement drift, increased faults, and higher maintenance demand
- Lead times for replacement analysers now extend to 30–42 weeks, making reactive replacement impractical

These factors increase the risk of:

- Failure to measure gas energy content accurately
- Non-compliance with gas quality and energy measurement requirements
- Commercial disputes arising from inaccurate billing
- Prolonged outages if a unit fails unexpectedly

Given the importance of accurate metering and the critical energy measurement function GCs provide, proactive replacement is required to maintain safe and reliable pipeline operation.

5.3. Assessment of options

The options considered for the access arrangement period are:

— Option 1: Do nothing

— Option 2: Replace obsolete GC & Moisture Analyser with new model

Risk assessment

The potential risks of both options are shown below.

Table 3–1: Risk assessment – GC & Moisture Analyser replacements

Risk Area	Potential Impact	Option 1 :		Option 2:	
		Likelihood / Impact	Inherent risk rating	Likelihood / Impact	Risk rating
Health & Safety	n/a		n/a	n/a	n/a
Environment	n/a		n/a	n/a	n/a
Operational	Disruption 1-3 months	Frequent / Significant	High	Remote / Significant	Low
People	n/a		n/a	n/a	n/a
Compliance	Regulatory breach	Frequent / Minor	Moderate	Remote / Minor	Negligible
Reputation & Customer	n/a		n/a	n/a	n/a
Financial	Revenue Impact <$1M	Frequent / Minimal	Low	Remote / Minimal	Negligible
Untreated risk			**HIGH**		**LOW**

Option 1 – Do Nothing (Reactive Replacement)

Under this option, obsolete analysers are operated until failure. This approach:

- Fails to meet AS 2885.3 requirements for managing foreseeable integrity risks
- Risks loss of energy measurement capability, impacting billing and contractual compliance
- Introduces significant risk of **extended outages** because of long equipment lead times
- Increases Opex due to frequent troubleshooting and procurement of high-cost legacy spares
- Creates unpredictable expenditure profiles and increases the likelihood of regulatory or customer concerns
- Is likely to still incur a significant percentage, or more, of the planned capital expenditure of option 2 as terminal failures force upgrades under premium rush pricing on as available equipment.

Option 1 is neither prudent nor technically acceptable.

Option 2 – Proactive Replacement of Obsolete GCs & Moisture Analysers (Preferred)

Option 2 involves replacing ageing GCs and Moisture Analysers before failure, based on criticality and asset condition.

Benefits include:

- Maintains accurate gas quality and energy-measurement capability
- Ensures compliance with contractual and regulatory requirements
- Reduces unplanned outages and associated customer impacts
- Provides a supply of spare parts for remaining legacy units
- Allows efficient resource allocation by aligning replacements with other site works
- Stabilises expenditure by avoiding costly reactive replacement
- Facilitates continued fleet wide vendor and model optimisation and standardisation

Given their criticality to metering accuracy and the known obsolescence issues, this option aligns with good industry practice and is strongly supported by APA's risk and performance data.

Financial assessment

In the near term, Option 1 appears to defer capital expenditure. However:

- Unplanned failures cost significantly more due to emergency mobilisation
- Outages may persist for months given long OEM lead times
- Customer and regulatory penalties far exceed planned replacement costs
- Predictability of expenditure is lost

Option 2:

- Enables coordinated work planning
- Allows efficient bundling of analyser replacements with other maintenance activities
- Delivers predictable, staged capital expenditure across the period
- Minimises lifecycle cost by avoiding emergency work and high-priced obsolete spares

Option 2 is therefore the prudent and efficient investment option.

Table 3–2: Financial assessment – Replace GCs & Moisture Analysers

	Commentary
Option 1: Replace GCs & Moisture Analysers when they fail	• Initial capital expenditure is lower than option 2 as expenditure is pushed out until failure occurs. However, replacements are more expensive given the efficiency losses (costs and staff/contractor resources) of unplanned works. • The expenditure is unpredictable and grows significantly once the level of failures exceeds the capacity of staff resources.
Option 2: Proactive replacement of GCs & Moisture Analysers	• Where possible, replacements take place with other works at the site, improving cost and resource efficiency. • Steady replacement rate over the coming years gives predictability in expenditure.

The preferred option that appropriately balances costs and risks is the Proactive replacement of GCs & Moisture Analysers

5.4. Proposed costs for FY28-FY32

The total capital expenditure for GC & Moisture Analyser replacements is:

- **$461k in FY28 for Woodroyd**
- **$462k in FY29 for Scotia**

Total: **$923k (Real $2026)**

These replacements will be delivered using APA resources supported by specialist vendors for configuration and commissioning. All procurement will be conducted in accordance with APA's Procurement Policy.

Table 3–3: Estimated annual cost GC & Moisture Analyser sites ($'000s Real 30 June 2026)

ALMPID	Description	FY28	FY29	FY30	FY31	FY32	Total
11592	Woodroyd - GC & Moisture Analyser	461					**461**
11591	Scotia - GC & Moisture Analyser		462				**462**
	FY Total	**461**	**462**	**0**	**0**	**0**	

6. GC only replacement

6.1. Project objective and scope

The objective of this project is to proactively replace obsolete **Gas Chromatographs (GCs)** at the **Brightview** and **Ellengrove** stations to ensure the continued accuracy of gas quality measurement and compliance with contractual and regulatory requirements.

The existing Emerson Model 500 GCs installed at these locations are now obsolete, with extremely limited OEM support and spare-parts availability. As GCs provide the heating value and compositional data used for energy billing, custody transfer, and compliance with gas specification limits, maintaining their reliability is essential.

Replacements will be planned and delivered based on station criticality, operational performance, and equipment condition, using APA resources supported by specialist vendors for configuration and commissioning.

6.2. Background

The Gas Chromatographs (GCs) installed at the Brightview and Ellengrove stations are more than 20 years old and are based on legacy platforms that are no longer supported by the original equipment manufacturer (OEM).

All GCs proposed for replacement under this business case are off support assets, with OEM support having ceased prior to preparation of this proposal. This includes:

- No manufacturer support or service agreements
- No firmware, software, or cybersecurity updates
- No OEM technical assistance
- No ongoing manufacture of critical spare parts

As a result, APA is reliant on diminishing stores of legacy components, third party repairs, or cannibalised parts from decommissioned units to maintain operability. This support arrangement is not sustainable and is inconsistent with prudent asset management practices.

The continued operation of unsupported GCs materially increases the likelihood of failure and the duration of outages, as many critical components have lead times of 30 to 42 weeks or are no longer available at all. The risk profile of these assets will continue to elevate? over time as remaining parts inventories reduce further.

Gas Chromatographs provide gas composition and heating value data used to determine billable energy quantities, support custody transfer, and demonstrate compliance with gas specification obligations. Failure or degraded performance of these instruments can result in:

- Inaccurate or estimated energy quantities
- Increased reliance on substituted data
- Commercial disputes with customers
- Potential non compliance with contractual, licence, and regulatory obligations

Given that OEM support has already ceased, future failures are foreseeable rather than unexpected. Continued operation of these assets would expose users to increasing operational and commercial risk and does not represent the prudent management of pipeline assets as required under the National Gas Rules.

Accordingly, proactive replacement of the Brightview and Ellengrove GCs is required to restore full vendor support, ensure reliable and auditable gas quality measurement, and minimise the risk of customer and regulatory impacts. The proposed replacements represent the lowest risk and most efficient means of maintaining measurement integrity across the Roma to Brisbane Pipeline.

6.3. Assessment of options

The options considered for the access arrangement period are:

- Option 1: Do nothing
- Option 2: Replace obsolete Gas Chromatograph with new model

Risk assessment

The potential risks of both options are shown below.

Table 4–1: Risk assessment – Gas Chromatograph replacements

Risk Area	Potential Impact	Option 1 :		Option 2:	
		Likelihood / Impact	Inherent risk rating	Likelihood / Impact	Risk rating
Health & Safety	n/a		n/a	n/a	n/a
Environment	n/a		n/a	n/a	n/a
Operational	Disruption 1-3 months	Frequent / Significant	High	Remote / Significant	Low
People	n/a		n/a	n/a	n/a
Compliance	Regulatory breach	Frequent / Minor	Moderate	Remote / Minor	Negligible
Reputation & Customer	n/a		n/a	n/a	n/a
Financial	Revenue Impact <$1M	Frequent / Minimal	Low	Remote / Minimal	Negligible
Untreated risk			**HIGH**		**LOW**

Option 1 – Do Nothing (Reactive Replacement)

Under this option, GCs would only be replaced upon failure. This creates a range of foreseeable risks:

- Inability to measure gas composition and heating value accurately
- Non-compliance with gas specification requirements
- Technical and commercial risks associated with inaccurate billing
- Inability to source spares due to discontinued OEM support
- Outages lasting several months because of long replacement lead times
- Increased maintenance effort and unplanned expenditure

The do-nothing approach is not technically or operationally acceptable and fails to meet AS 2885 requirements for managing foreseeable integrity risks.

Option 2 – Proactive GC Replacement (Preferred)

Option 2 involves replacing the obsolete GCs at Ellengrove and Brightview before failure occurs.

Benefits include:

- Maintains accurate gas quality and energy-measurement capability
- Ensures compliance with gas specification and contractual measurement requirements
- Avoids prolonged outages associated with long OEM lead times
- Provides salvageable parts that can support other remaining legacy GCs
- Enables efficient resource planning and alignment with other maintenance activities
- Significantly improves measurement reliability for customers and APA operations

This approach reflects good industry practice for managing critical measurement assets and is strongly supported by APA's asset condition and risk assessments.

Financial assessment

While Option 1 may appear to defer capital costs, it leads to significantly higher lifecycle expenditure due to:

- Inefficient, unplanned field mobilisation
- Emergency procurement of scarce legacy components
- Potential financial exposure from measurement inaccuracies
- Regulatory and customer consequences associated with gas-quality non-compliance

Option 2 provides predictable, efficient, and planned expenditure, reducing long-term costs and risk. Given the clear operational, commercial, and compliance benefits, **Option 2 is the prudent and efficient investment option**.

Table 4–2: Financial assessment – CP unit upgrades ($ Real 30 June 2026)

	Commentary
Option 1: Replace Gas Chromatographs when they fail	• Initial capital expenditure is lower than option 2 as expenditure is pushed out until failure occurs. However, replacements are more expensive given the efficiency losses (costs and staff/contractor resources) of unplanned works. • The expenditure is unpredictable and grows significantly once the level of failures exceeds the capacity of staff resources. • Avoided costs in the near-term are more than offset by regulatory fines and the financial costs and penalties arising from reputational damage and the potential loss of the AGP operating licence.
Option 2: Proactive replacement of Gas Chromatographs	• Where possible, replacements take place with other works at the site, improving cost and resource efficiency. • Steady replacement rate over the coming years gives predictability in expenditure.

The preferred option that appropriately balances costs and risks is the Proactive replacement of Gas Chromatographs

6.4. Proposed costs for FY28-FY32

Proposed expenditure for GC-only replacements:

- **FY30 – Ellengrove GC Replacement:** $290k
- **FY31 – Brightview GC Replacement:** $233k

Total: **$623k (Real $2026)**

These works will be delivered using APA resources, with specialist vendors engaged for configuration and commissioning in accordance with APA's Procurement Policy.

Table 4–3: Estimated annual cost of GC upgrades ($'000s Real 30 June 2026)

ALMPID	Description	FY28	FY29	FY30	FY31	FY32	Total
	Ellengrove GC Upgrade			290			**290**
	Brightview GC Upgrade				233		**233**
	FY Total	**0**	**0**	**290**	**233**	**0**	

7. Turbine Meter replacements

7.1. Project objective and scope

The objective of this project is to proactively replace ageing **Turbine Meters** at the **Redbank Plains** and **Toowoomba** metering stations to ensure continued accuracy, reliability, and compliance with gas measurement and contractual requirements.

The existing 4” Turbine Meters have limited diagnostic capability, are increasingly difficult to calibrate or support and will reach the end of their useful life (20 years) during the access arrangement period. Replacing these units with modern **Coriolis Meters** will significantly improve measurement accuracy, reduce operational risks, and provide enhanced diagnostics to support APA’s Accuracy Verification Testing (AVT) processes.

The project scope includes procurement, installation, commissioning and integration of Coriolis meters, including all necessary mechanical and electrical modifications, to ensure seamless replacement of existing equipment.

7.2. Background

The Turbine Meters at Redbank Plains and Toowoomba are reaching the end of their functional and supportable life. Current issues include:

- Outdated diagnostics that limit the ability to perform AVT
- Lack of availability of high-pressure gas calibration facilities in Australia
- Difficulty sourcing spare parts for ageing turbine meters
- Increasing maintenance and operational effort to maintain acceptable performance

By contrast, **Coriolis Meters** provide several advantages:

- No rotating components, significantly improving reliability
- Rich diagnostic capability supporting AVT and integrity programs
- Ability to be calibrated using water by Australian facilities, reducing cost and complexity
- Lower lifecycle costs and reduced measurement uncertainty

These improvements support APA’s long-term measurement integrity strategy and provide customers with more consistent and accurate metering outcomes.

7.3. Assessment of options

The options considered for the access arrangement period are:

- Option 1: Do nothing
- Option 2: Replace obsolete Turbine meters with industry standard Coriolis meter.

Risk assessment

The potential risks of both options are shown below.

Table 5–1: Risk assessment – Turbine Meter replacements

Risk Area	Potential Impact	Option 1 :		Option 2:	
		Likelihood / Impact	Inherent risk rating	Likelihood / Impact	Risk rating
Health & Safety	n/a		n/a	n/a	n/a
Environment	n/a		n/a	n/a	n/a
Operational	Disruption 1-3 months	Frequent / Significant	High	Remote / Significant	Low
People	n/a		n/a	n/a	n/a
Compliance	Regulatory breach	Frequent / Minor	Moderate	Rare / Minor	Negligible
Reputation & Customer	n/a		n/a	n/a	n/a
Financial	Revenue Impact <$1M	Frequent / Minimal	Low	Rare / Minimal	Negligible
Untreated risk			**HIGH**		**LOW**

Option 1 – Do Nothing (Reactive Replacement)

Under this option, existing Turbine Meters would remain in service until failure or unacceptable performance is observed. This approach:

- Increases the risk of measurement inaccuracies
- Elevates operational costs due to troubleshooting and spares procurement
- Creates potential non-compliance risks with contractual measurement requirements
- Keeps APA reliant on obsolete equipment with limited support
- May result in extended outages due to procurement lead times

Option 1 is not technically acceptable and is inconsistent with prudent operation under the RBP Pipeline Licence.

Option 2 – Proactive Turbine Meter Replacement (Preferred)

Option 2 involves replacing ageing Turbine Meters with modern Coriolis Meters before failure occurs.

Key benefits include:

- Improved measurement accuracy and reduced uncertainty
- Enhanced diagnostic capabilities for AVT
- No rotating parts, improving long-term reliability
- Compatibility with Australian calibration facilities

- Efficient resource planning by aligning replacement with other site works
- Reduced probability of unplanned outages and associated customer impacts

This approach is strongly aligned with good industry practice and meets the expectations of stakeholders regarding accuracy and reliability of metering equipment.

Financial assessment

While Option 1 may appear to delay expenditure, it results in higher total lifecycle costs, including:

- Emergency field mobilisation
- Premium pricing for obsolete spares
- Higher maintenance hours due to aging components
- Increased risk of inaccurate measurement and related commercial consequences

Option 2 provides predictable expenditure, facilitates efficient installation planning, and materially reduces whole-of-life cost.

Given the significant operational and compliance benefits, **Option 2 is the prudent and efficient investment choice**.

Table 5–2: Financial assessment – Replace Turbine Meters ($ Real 30 June 2026)

Description	
Option 1: Replace Turbine Meters when they fail	• Initial capital expenditure is lower than option 2 as expenditure is pushed out until failure occurs. However, replacements are more expensive given the efficiency losses (costs and staff/contractor resources) of unplanned works. • The expenditure is unpredictable and grows significantly once the level of failures exceeds the capacity of staff resources.
Option 2: Replace Turbine Meters proactively	• Where possible, replacements take place with other works at the site, improving cost and resource efficiency. • Steady replacement rate over the coming years gives predictability in expenditure.

The preferred option that appropriately balances costs and risks is Option 2, Proactive replacement of Turbine Meters.

7.4. Proposed cost for FY28-FY32

The estimated expenditure for Turbine Meter replacements is:

- **FY32 – Redbank Plains Turbine Meter replacement:** $160k
- **FY32 – Toowoomba Turbine Meter replacement:** $233k

Total: $393k (Real $2026)

The replacement program will use APA resources supported by specialist vendors for configuration and commissioning, under APA Procurement Policy requirements.

Table 5–3: Estimated yearly cost of Turbine meter replacements ($'000s Real 30 June 2026)

Description	FY28	FY29	FY30	FY31	FY32	Total
Redbank Plains - Turbine Meter Upgrade					160	**160**
Toowoomba - Turbine Meter Upgrade					233	**233**
FY Total	**0**	**0**	**0**	**0**	**393**	

8. Controlwave Micro RTU & Flow Computers upgrade

8.1. Project objective and scope

The objective of this project is to progressively upgrade the ControlWave Micro (CWu) flow computer and RTU platform installed across approximately 105 sites on the RBP. Emerson has announced that the CWu platform will become end-of-support in January 2030, after which firmware updates, spare parts, and technical assistance will no longer be available.

To ensure continued operational capability, cybersecurity resilience, and reliability of metering and control functions, APA proposes a multiyear replacement program.

Scope includes:

- Replacement of obsolete CWu flow computers at affected sites
- Selection and deployment of a modern, APA-endorsed RTU/flow computer platform
- Configuration, testing, commissioning, and integration of new units
- Alignment of replacements with other scheduled site works to maximise efficiency

This ensures sustained SCADA communication, reliable metering, and safe pipeline control operations.

8.2. Background

The ControlWave Micro platform is widely deployed across the RBP for flow computation, metering, and remote control functions. As the platform approaches end-of-support:

- Spare parts will become scarce or unavailable
- Firmware and security updates will cease
- Age-related hardware reliability issues will increase
- Cybersecurity vulnerabilities may emerge without vendor patching
- Outages may be prolonged if failures occur post-2030

Although current performance is acceptable, the withdrawal of vendor support presents a **foreseeable and material risk** to operational reliability if the units remain in service beyond 2030.

This transition period presents an opportunity for APA to migrate to a modern, standardised RTU/flow computer platform with:

- Improved long-term support
- Enhanced cybersecurity features
- Improved performance and diagnostics
- Better lifecycle integration with APA's current control systems

8.3. Assessment of options

Three options were considered for the Access Arrangement period..

— Option 1: Do Nothing / Reactive Replacement (Run to Failure)

— Option 2: Planned Replacement Program (Preferred)

— Option 3: Maintain the Current Fleet Using Stockpiled Spares (Short-Term Mitigation)

Risk assessment

If no action is taken prior to vendor support ending in 2030, the large installed base of CWu devices poses increasing risks:

- Higher likelihood of extended outages
- Maintenance difficulties due to unavailable spares
- Elevated cybersecurity exposure
- Impacts to operational efficiency, metering accuracy, and SCADA reliability

A staged replacement program (Option 1) reduces all major risks to **Low**, providing a stable and well-managed transition.

Table 5–1: Risk assessment – Controlwave Micro RTUs & Flow Computers replacement

Risk Area	Potential Impact	Option 1		Option 2	
		Likelihood / Impact	Inherent risk rating	Likelihood / Impact	Risk rating
Health & Safety	Fatality or injury	Occasional / Major	High	Rare / Major	Low
Environment	n/a	n/a	n/a	n/a	n/a
Operational	Disruption 1-3 months	n/a	n/a	n/a	n/a
Compliance	Regulatory breach	n/a	n/a	/a	n/a
Reputation & Customers	Adverse media, negative feedback	Occasional / Major	High	Rare / Major	Low
Financial	Repair costs	Occasional / Major	High	Rare / Major	Low
Untreated risk			**HIGH**		**LOW**

Option 1 – Do Nothing / Reactive Replacement (Run to Failure)

Under this approach, APA would continue operating the CWu fleet until individual devices fail and all spare parts for decommissioned units are consumed and then replace them reactively.

This option exposes APA to significant, foreseeable, and escalating risks:

Operational risks

- Failures become more likely as units age beyond 2030.
- Loss of SCADA visibility or control may lead to operational incidents.
- Outages may be prolonged due to unavailability of spares.

Cybersecurity risks

- No vendor security updates, patches, or firmware support after 2030.
- Increased vulnerability to cyber-attack or control-system compromise.

Compliance and safety risks

- Potential breaches of RBP Pipeline Licence obligations relating to control system reliability.
- Reduced ability to maintain metering accuracy and safe operational control.

Financial and resourcing risks

- Reactive mobilisations are inefficient and expensive.
- Failure clustering may overwhelm APA's field resources.
- Emergency sourcing of obsolete equipment commands premium costs.

Conclusion:
Option 1 is **not prudent, not efficient, and inconsistent with NGR 79**, as it exposes APA to avoidable operational, safety, cybersecurity, and financial risks

Option 2 – Planned Replacement Program (Preferred)

Under this option, APA implements a staged replacement program for all CWu units before 2030.

Benefits include:

- sustained metering, SCADA reliability and operational control
- modern cybersecurity protections and patching
- predictable and efficient expenditure
- efficient bundling with other site works
- full alignment with APA's future control-system architecture

This option provides the lowest lifecycle cost, lowest risk profile, and highest operational reliability.

Option 3 – Maintain the Current Fleet Using Stockpiled Spares (Short-Term Mitigation)

This option involves procuring additional CWu spare parts before they become unavailable.

Limitations include:

- does not resolve cybersecurity vulnerabilities post-2030
- spare-parts inventory will eventually be exhausted
- failures will still increase with age, resulting in operational disruptions
- creates long-term uncertainty and does not represent a complete solution

Option 2 offers short-term risk mitigation but is not a viable long-term approach given the large fleet size in operation across the RBP.

Financial assessment

Table 5–2: Financial assessment – satellite data loggers ($ Real 30 June 2026)

Description	
Option 1: Do Nothing	• Unpredictable, volatile expenditure • High emergency mobilisation costs • Premium pricing for obsolete equipment • Long outage durations • Does not meet NGR 79 prudency or efficiency requirements
Option 3: Planned Replacement (Preferred)	• Smooths expenditure over multiple years • Efficient bundling of work • Avoids emergency costs and operational disruptions • Represents lowest sustainable lifecycle cost
Option 2: Spares-Only Approach	• Defers rather than avoids expenditure • Increasing reactive costs over time • Does not address cybersecurity or long-term support risk

The preferred option that appropriately balances costs and risks is Option 1, Planned Replacement Program

8.4. Proposed cost for FY28-FY32

Planned expenditure for Flow Computer upgrades across the access-arrangement period is:

- **Total: $2.029m (Real $2026)**

These works will be completed by APA resources, with specialist support engaged where site-specific configuration is required. All procurement will comply with APA's Procurement Policy.

Table 5–3: Annual estimated cost of satellite data loggers ($'000s Real 30 June 2026)

ALMPID	Description	FY28	FY29	FY30	FY31	FY32	Total
	Controlwave Micro RTUs & Flow Computer end of Life replacement	404	404	406	407	408	**2,029**
	FY Total	**404**	**404**	**406**	**407**	**408**	

APA

Australia's energy infrastructure partner

Facilities Business Case

Roma to Brisbane Gas Pipeline Access Arrangement 2028–32

29 May 2026

Contents

1. Overview

Number/ identifier	A-5_Facilities
Description of Issue/ Project	This business case covers stay-in-business capital works required to maintain the safe, reliable, and compliant operation of the Roma to Brisbane Pipeline (RBP). The scope includes upgrades and renewals to electrical, instrumentation, and mechanical components across above-ground facilities and associated compounds. Two programs are included: 1. Earthing upgrades (PP11386) 2. Station Painting Program (PP11629) These works are essential to sustaining asset integrity, ensuring ongoing compliance with technical and safety obligations, and supporting efficient long-term operation.
Options considered	**Option 1 – Run-to-failure approach** Assets are allowed to degrade to end-of-life or failure. This results in increased risk of non-compliance, unplanned outages, higher reactive maintenance costs, and potential licence implications. **Option 2 – Planned proactive replacement and upgrade program (Preferred)** Assets are replaced or refurbished at an appropriate interval to maintain safe, reliable, and efficient services. This avoids unplanned failures, mitigates regulatory and safety risks, and provides predictable expenditure.
Proposed Solution	Option 2 is preferred as it balances risk, cost efficiency, and regulatory compliance. A proactive program avoids unplanned failures, mitigates safety and regulatory risks (including potential licence impacts), and provides predictable expenditure aligned with good industry practice.
Estimated Cost	$2.32 million
Relevant standards	• AS 2832.1 Cathodic Protection of Metals • AS 2885.0 Pipelines – Gas and Liquid Petroleum • AS 3000 Electrical Installations • AS 2885.3 Operations and Maintenance • RBP Pipeline Licence
Stakeholder Engagement	• Scope discussed during RBP Access Arrangement Stakeholder Meetings #3 (25/11/2025); #4 (10/02/2026); and #5 (31/03/2026)
Consistency with National Gas Rules (NGR)	This program meets the criteria under NGR 79 because it: • Is **necessary** to maintain safety and integrity of pipeline services (79(2)(c)(i)–(ii)) • Is expenditure a prudent operator acting efficiently would incur (79(1)(a)) • Is consistent with **good industry practice** and mandatory Australian Standards

2. Program details

2.1. Background

Above-ground facilities on the Roma to Brisbane Pipeline (RBP) play a critical role in supporting the safe, reliable, and compliant operation of the pipeline. These facilities house essential electrical, mechanical, and instrumentation assets that enable pipeline control, protection, maintenance access, and safe operation under normal and abnormal conditions.

Facility assets—including earthing systems, structural steelwork, pipe supports, platforms, and protective coatings—are subject to ongoing degradation due to environmental exposure, ageing materials, and operational wear. Without timely intervention, deterioration of these assets can introduce safety hazards, impair equipment performance, and increase the likelihood of unplanned outages or regulatory non-compliance.

In particular:

- **Inadequate earthing systems** elevate electrical safety risks for personnel and contractors, increase the potential for equipment damage during fault or lightning events, and expose APA to WHS and electrical-safety non-compliance.
- **Degraded protective coatings and corrosion** on above-ground infrastructure reduce structural integrity, shorten asset life, and increase the probability that minor defects escalate into more costly and disruptive failures.

While these facilities do not directly perform metering or billing functions, their condition materially influences operational reliability and APA's ability to deliver pipeline services without disruption. Failures or safety incidents at above-ground sites can result in:

- operational constraints or outages affecting gas transportation;
- increased safety risk to field personnel and contractors; and
- reputational and regulatory impacts that ultimately affect customers.

Many of the facilities included in this business case were constructed decades ago and are now approaching or exceeding expected refurbishment intervals. Asset condition assessments, audits, and routine inspections have identified areas where continued "run-to-failure" approaches would result in increased safety exposure, greater likelihood of non-compliance with applicable Australian Standards and licence obligations and higher long-term costs.

The Facilities program addresses these risks through a structured, proactive approach to maintaining critical aboveground assets. By renewing earthing systems and implementing a rolling station painting program, APA can:

- sustain safe access and working conditions at pipeline facilities;
- preserve the integrity and serviceability of structural assets;
- avoid inefficient, reactive maintenance and emergency repairs; and
- support the ongoing reliable delivery of pipeline services to customers.

Proactive facilities investment therefore represents prudent asset stewardship and contributes to the **lowest sustainable cost of service provision**, consistent with good industry practice and the requirements of the National Gas Rules.

2.2. Assessment of options

Two high-level options are considered for the Facilities program:

Option 1: Reactive replacement

Assets are replaced or repaired only following failure or significant deterioration. This approach creates unplanned expenditure, higher repair costs, inefficient resource allocation, and heightened risk of regulatory breaches.

Option 2: Planned proactive replacement (Preferred)

Ensures predictable expenditure, coordinated work planning, improved efficiency, and reduced safety and reliability risks.

Financial assessment

A consideration of the pros and cons of the expected financial outlays for both options is shown below. Net Present Value calculations have not been undertaken as a realistic expenditure profile is unable to be ascertained for option 1. Given end-of-life replacement and rectification costs are inevitable, this business case demonstrates that the proposed expenditure is efficient and appropriate to manage the associated risks.

Table 2-1: Financial assessment for the Facilities business case

	Commentary
Option 1: Accept non-conformance with regulations and asset failure	• Unplanned approach to replacements and rectification leads to lumpy and more unpredictable expenditure. • Replacements are more expensive given the efficiency losses (costs and staff/contractor resources) of unplanned works compared to planned works. • Expenditure grows significantly once the level of failures exceeds the capacity of staff resources –significant increased costs for contractors to be on stand-by. • Avoided costs in the earlier years are more than offset by regulatory fines and the financial costs and penalties arising from reputational damage, legal action and the loss of the RBP operating licence.
Option 2: Planned approach to managing risks and costs	• Where possible, replacements take place with other works at the site, improving cost and resource efficiency. • Steady replacement rate over the coming years gives predictability in expenditure. • Expect a reduction in some costs over time ahead of reaching a stabilised level of expenditure.

The risk and financial assessments above support the preferred option (option 2) as appropriately balancing costs and risks.

2.3. Consistency with the National Gas Rules and other regulations

The RBP is a major national pipeline and appropriate maintenance of the pipeline facilities enable the pipeline equipment to operate in accordance with its design basis, relevant standards and regulations.

As the expenditure avoids safety and reliability issues APA consider this program to be consistent with the requirements of Rule 79 of the National Gas Rules, Australian Standards and other legislative obligations. The capital expenditure is:

- Necessary to maintain and improve the safety of services and maintain the integrity of services to customers and is of a nature that a prudent service provider would incur
- Consistent with the expenditure that a prudent service provider acting efficiently would incur
- Consistent with accepted and good industry practice
- Aligned with:
  - AS 2885.3 Pipelines: Gas and Liquid Petroleum Operations and Maintenance

  - AS3000: Electrical Installations, and
  - AS 2832.1 Cathodic Protection of Metals: Pipes and Cables
- Consistent with Australian Standard AS2885 in balancing the reduction of risk to as low as reasonably practicable considering the relevant costs.

Most of the work will be undertaken by RBP staff. Where external contractors are used, they will be procured in line with APA's Procurement Policy, require the necessary skills and experience and have a demonstrated track record of completing work in a safe and cost-effective manner.

2.4. Proposed costs for FY28-FY32

The total cost of the Facilities business case is shown below. More detail on each asset type and the capital expenditure to be undertaken is found in sections 3 to 7 of this document.

Table 2–3 Total cost for Site equipment business case ($'000s Real 30 June 2026)

Description	FY28	FY29	FY30	FY31	FY32	Total
Project Proposal for Earthing upgrades	231	231	232	233	233	**1,160**
Station Painting	231	231	232	233	233	**1,160**
FY Total	**462**	**462**	**464**	**466**	**466**	**2,320**

3. Earthing Upgrades

3.1. Project objective and scope

The objective of the Earthing Upgrades Program is to ensure that the Roma to Brisbane Pipeline (RBP) electrical installations comply with relevant Australian Standards and safety legislation, and to mitigate risks associated with inadequate earthing and lightning protection systems. Inadequate earthing and lighting protection results in a material increase in electrocution risk on pipeline facilities. This is due to pipelines acting as large cables and are documented to pick up and carry the energy of an electrical transmission fault or lightning strike considerable distances.

The scope of work includes:

- Developing updated earthing system designs, drawings, and layout documents to reflect the identified requirements for compliance and safety.
- Implementing remediation and upgrade works to rectify deficiencies, prioritised based on site criticality, worker safety risk, and operational impact.
- Updating asset maintenance records within Maximo to ensure compliance with APA's Maintenance Strategy Library and ongoing governance of electrical integrity.

The program is essential to maintaining safe operating conditions for APA personnel and contractors, protecting critical infrastructure, and ensuring APA meets its obligations under WHS legislation, pipeline licence conditions, and relevant Australian Standards.

3.2. Background

A recent earthing audit across the RBP network identified a range of non-conformances and degradation issues across multiple above-ground sites. In collaboration with Operations, each gap was risk-assessed based on site function, environmental exposure, and potential impact on personnel safety and pipeline operations.

Six of the 29 assessed sites—Condamine SS, Redbank RMS, Bellbird Park RMS/SS, Bowenville MLVs, Norwin Road MLVs, and Richie Road MLV—were classified as **Moderate (MOD) risk** due to their operational criticality, fault current exposure, and the site-specific consequences of an earthing system failure.

Sub-standard earthing systems increase the risk of:

- Electric shock hazards, including step and touch potential risks during fault events
- Damage to sensitive electrical and communication assets
- Lightning-related surge impacts
- Unplanned operational disruptions
- Non-compliance with WHS obligations and AS/NZS 3000 / AS 1768

Earthing systems are a fundamental safety control for pipeline facilities, ensuring safe fault dissipation and providing critical protection for both personnel and equipment. Failure to maintain these systems in accordance with standards not only increases the likelihood of an electrical incident but also exposes APA to regulatory enforcement, safety breaches, and reputational harm.

This business case proposes a structured upgrade program to rectify deficiencies and return the RBP earthing systems to compliant and safe operating condition.

3.3. Assessment of options

To address the earthing-related non-conformances identified across the Roma to Brisbane Pipeline (RBP) facilities, APA has assessed two feasible options for the 2028–32 Access Arrangement period. This analysis considers safety obligations, regulatory compliance, asset integrity requirements and long-term cost efficiency.

- Option 1: Replace structures when they fail and repair ground damage only where safety maybe compromised or negative publicity may arise.
- Option 2: Proactively upgrade compounds and associated structures when the benefits of replacement exceed the costs and potential safety and regulatory risks.

3.3.1. Risk assessment

The potential risks of both options are shown below.

The main concerns arising from sub-standard earthing relate to the safety of staff and contractors. WHS legislation creates a positive obligation for RBP to ensure, as far as is reasonably practicable, the health and safety of workers and other persons.

Failing to meet the requirements of the legislation significantly increases the financial risk arising from legal action.

Table 3–1: Risk assessment – Earthing upgrades

Risk Area	Potential Impact	Option 1 :		Option 2:	
		Likelihood / Impact	Inherent risk rating	Likelihood / Impact	Risk rating
Health & Safety	n/a	Remote / Major	Moderate	Rare / Major	Low
Environment	n/a		n/a	n/a	n/a
Operational	Disruption 1-3 months	Unlikely / Significant	Moderate	Remote / Significant	Low
People	n/a		n/a	n/a	n/a
Compliance	Regulatory breach	Occasional / Minor	Moderate	Remote / Minor	Negligible
Reputation & Customer	n/a		n/a	n/a	n/a
Financial	Revenue Impact <$1M	Occasional / Minor	Low	Remote / Minor	Negligible
Untreated risk			**MODERATE**		**LOW**

3.3.2. Option 1 – Reactive Repair Upon Failure

Under this option, earthing systems and associated structures are repaired only once failure occurs or where deterioration presents an immediate and observable safety concern. While this approach defers expenditure in the short term, it is inconsistent with the requirements of AS/NZS 3000, AS 1768, WHS legislation, and APA's licence obligations.

A reactive approach creates extended periods in which known hazards remain unaddressed, given the operational constraints of regional access, resourcing availability, and competing priorities. This materially increases the probability of:

- Electric shock or step-potential hazards to workers at affected sites.
- Regulatory non-compliance and potential enforcement action.
- Disrupted operations due to unplanned outages and emergency works.
- Inefficient resource allocation, as unplanned remediation demands higher labour, mobilisation and contractor costs.

This option fails to meet the requirement under AS2885 and WHS legislation to reduce risk to "so far as is reasonably practicable" (SFAIRP). As such, it represents a high-risk and inefficient approach that is not prudent nor consistent with the NGR capital expenditure criteria.

3.3.3. Option 2 – Proactive Earthing Upgrade Program (Preferred Option)

Option 2 involves completing the detailed earthing audit, developing compliant design documentation, and implementing a structured remediation program across prioritised sites. The approach directly responds to the audit findings that six sites—Condamine, Redbank, Bellbird Park, Bowenville, Norwin Road and Richie Road—were assessed as "Moderate" risk due to criticality, geographical exposure, and operational importance.

This option ensures compliance with:

- AS/NZS 3000 (Electrical Installations)
- AS 1768 (Lightning Protection)
- AS 2885.3 (Pipeline Operations and Maintenance)
- WHS obligations requiring proactive risk mitigation
- APA's Pipeline Licence conditions

A proactive remediation strategy reduces risk exposure by addressing deficiencies before they deteriorate to hazardous conditions. It also improves efficiency by enabling work to be completed in conjunction with other site activities, optimising mobilisations and supporting predictable program delivery.

Due to the avoidance of issues associated with electrical works on site Option 2 aligns with the NGR Section 79 criteria because it is:

- **Necessary** to maintain and improve the safety and integrity of services.
- **Prudent**, as a reasonable service provider would act to mitigate WHS and regulatory risks.
- **Efficient**, delivering smoother expenditure profiles and lower whole-of-life costs than reactive repairs.
- **Consistent with good industry practice**, supporting robust asset governance and risk management.

Given these considerations, Option 2 is the preferred and justified option for the 2028–32 Access Arrangement period.

3.3.4. Financial assessment

A consideration of the pros and cons of the expected financial outlays for both options is shown below. Net Present Value calculations have not been undertaken as a realistic expenditure profile for option 1 is unable to be ascertained. In addition, replacement costs are expected in the near-term under both options, so the more important question is how the spend should be balanced to appropriately manage the associated risks.

Table 3-1: Financial assessment of RTU upgrades

	Commentary
Option 1: Reactive Repair Upon Failure	• Although Option 1 (reactive repairs upon failure) defers expenditure into later years, it represents a materially higher whole-of-life cost due to the inefficiency and unpredictability of unplanned works. Reactive repairs incur higher mobilisation and contractor costs and significantly increase the probability of regulatory penalties, safety incidents, and operational downtime. These costs are difficult to accurately forecast, making the expenditure profile inherently volatile.
Option 2: Proactive Earthing Upgrade Program (Preferred Option)	• Option 2 (proactive, risk-based earthing upgrades) provides a controlled and efficient expenditure profile, enabling planned mobilisations, predictable labour requirements, and efficient bundling of work across geographically aligned sites. This approach reduces safety and compliance risk to ALARP and delivers the lowest sustainable cost to customers, consistent with the NGR capital expenditure criteria.

The table therefore supports Option 2 as the prudent and efficient option, ensuring compliance, reducing risk, and smoothing expenditure across the Access Arrangement period.

3.4. Proposed costs for FY28-FY32

APA proposes to implement the proactive earthing upgrade program over the 2028–32 period at a total capital cost of **$1.2 million (Real $2026)**. This expenditure reflects the scope of work required to achieve compliance with AS/NZS 3000, AS 1768, and AS 2885.3, and to remediate the priority sites identified through the audit.

The program will be sequenced to align with operational access windows, site criticality, and resourcing availability. Work will be performed primarily by APA personnel, supported by specialist contractors for design verification, testing, and installation where required. All procurement will follow APA's Procurement Policy to ensure value-for-money delivery.

Expenditure has been smoothed across the period to provide efficient, predictable delivery and to align with APA's internal resourcing capability:

Table 3–3: Proposed 2028-2032 costs for Earthing upgrades ($'000s Real 30 June 2026)

Description	FY28	FY29	FY30	FY31	FY32	Total
Project Proposal for Earthing upgrades	231	231	232	233	233	**1,160**

This investment level reflects:

- Efficient mobilisation and bundling of works.
- Labour and material requirements informed by the audit and APA's prior experience.
- A risk-based prioritisation method ensuring earlier treatment of higher-risk sites.
- Avoided costs associated with unplanned failures, regulatory action, or safety incidents.

The proposed expenditure is therefore **prudent, efficient, and consistent with the NGR**, as it ensures APA can maintain compliance with mandatory safety and electrical standards while sustaining the safe operation of the RBP.

4. Station Painting Program

4.1. Project objective and scope

The objective of the Station Painting Program is to implement a structured, risk-based coating and corrosion-protection program across above-ground assets on the Roma to Brisbane Pipeline (RBP). The program aims to:

- Maintain the integrity and serviceability of above-ground facilities in accordance with the Gas Supply Act 2003 (Qld) and AS 2885.3.
- Mitigate corrosion risk through proactive coating renewal, reducing the likelihood of structural degradation and premature asset failure.
- Ensure continued compliance with APA's asset integrity and safety obligations by addressing coating deterioration before it affects operational performance or safety.
- Establish a multi-year maintenance cycle that delivers stable, predictable costs and reduces long-term remediation volatility.

The scope includes surface preparation, coating removal, application of anti-corrosion and protective coating systems, and inspection/quality verification on station pipework, steel structures, platforms, and associated above-ground equipment.

4.2. Background

The RBP operates in harsh Queensland environmental conditions characterised by elevated UV exposure, high ambient temperatures, seasonal rainfall, and storm activity. These conditions accelerate degradation of protective coatings on exposed steel and process equipment.

Under the Gas Supply Act 2003 (Qld), pipeline operators must maintain gas infrastructure in a safe and serviceable condition and implement appropriate corrosion prevention measures. Degraded coatings compromise corrosion resistance, reducing structural integrity and increasing the likelihood of:

- Progressive corrosion of steel infrastructure
- Increased probability of safety-related defects
- Escalating long-term remediation costs
- Shortened asset life
- Regulatory scrutiny regarding maintenance and integrity management obligations

Current coating remediation is largely reactive and condition based. This approach increases the risk that localised corrosion progresses to a point where more extensive, invasive, and costly rectification is required. A structured coating renewal program is necessary to restore compliance with integrity standards and deliver long-term cost efficiency.

4.3. Assessment of options

Two options have been considered for this project:

- Option 1: No Change – Continue Reactive, Condition-Based Coating Remediation
- Option 2: Implement a structured, risk-based, multi-year coating program to proactively manage corrosion

4.3.1. Risk assessment

The potential risks of both options are shown below.

Failure to proactively manage coating degradation may result in significantly higher capital expenditure in future years due to structural replacement rather than preventative maintenance.

Table 4–1: Risk assessment – Station Painting Program

Risk Area	Potential Impact	Option 1 :		Option 2:	
		Likelihood / Impact	Inherent risk rating	Likelihood / Impact	Risk rating
Health & Safety	n/a	n/a	n/a	n/a	n/a
Environment	n/a	n/a	n/a	n/a	n/a
Operational	Disruption 1-3 months	Remote / Major	Moderate	Remote / Minimal	Low
People	n/a		n/a	n/a	n/a
Compliance	Regulatory breach	Remote / Minimal	Negligible	Remote / Minor	Negligible
Reputation & Customer	n/a		n/a	n/a	n/a
Financial	Revenue Impact <$1M	Remote / Minimal	Negligible	Remote / Minor	Negligible
Untreated risk			**MODERATE**		**NEGLIGIBLE**

4.3.2. Option 1

Under this option, only operational "touch up" coating repairs occur when visible deterioration is identified during routine inspections. Although this defers short-term expenditure, these repairs are generally short-term fixes for localised areas, with a lower standard of surface preparations and not addressing the systemic chemical breakdown and failure of the coating system due to UV and other environmental exposures. This generally results either a higher lifecycle cost than structured coating remediation or it allows corrosion to progress to advanced stages, increasing the probability of defects, higher steel remediation costs, and potential reductions in asset life.

This approach is misaligned with a prudent asset management strategy because deterioration continues unchecked until conditions require more extensive intervention. It also increases the risk of non-compliance with the Gas Supply Act 2003 (Qld), AS 2885.3, and APA's internal asset integrity standards.

4.3.3. Option 2

This option establishes a systematic renewal program that prioritises coating works based on asset criticality, environmental exposure, inspection findings, and corrosion risk. By proactively maintaining protective coatings, APA can:

- Extend asset life through preventative corrosion control
- Reduce safety and integrity risks associated with degraded structures
- Stabilise long-term maintenance expenditure
- Demonstrate strong integrity governance in line with AS 2885.3 and regulatory expectations
- Avoid future high-cost structural repairs or asset replacements

Option 2 is consistent with good industry practice, reduces risks to ALARP, and aligns with the NGR requirements for prudent and efficient capital expenditure.

Financial assessment

Table 4–2: Financial assessment – Station Painting Program ($ Real 30 June 2026)

	Commentary
Option 1: Continue to remediate coating on a reactive and condition-based basis	• Progressive corrosion of structural steel and pipework • Increased probability of integrity-related defects • Escalating remediation costs as corrosion advances • Reduced asset design life • Increased safety risk to personnel • Elevated risk of regulatory scrutiny under the Gas Supply Act 2003 • Potential environmental and supply reliability impacts
Option 2: Implement a structured, risk-based, multi-year coating program to proactively manage corrosion	• Aligns with Gas Supply Act 2003 maintenance obligations • Reduces corrosion risk and safety exposure • Extends asset life • Stabilises long-term Opex • Demonstrates strong integrity governance

Based on the risk and financial assessments above, the preferred option that appropriately balances costs and risks is the implementation of the proactive coating program (option 2).

4.4. Proposed costs for FY28-FY32

The Station Painting Program requires annual investment to deliver a rolling schedule of works aligned with inspection cycles and site access planning. Sites selected for coating works will be determined through ongoing maintenance and corrosion-monitoring activities.

The proposed expenditure profile provides predictable and steady annual funding summing to **$1.2m** across the period, supporting efficient bundling of surface preparation, coating application, and quality assurance activities.

Table 4–3: Estimated annual cost of Station Painting ($'000s Real 30 June 2026)

Description	FY28	FY29	FY30	FY31	FY32	Total
Station Painting	231	231	232	233	233	**1,160**

This cost structure reflects:

- Efficient mobilisation and use of contractor resources
- Standardised coating specifications across RBP sites
- A risk-based prioritisation approach ensuring alignment with integrity needs
- Avoided future structural repair or asset replacement costs through proactive corrosion control

The proposed program is therefore prudent, efficient, and consistent with the NGR, enabling APA to maintain pipeline integrity and manage corrosion risks in a structured and sustainable manner.

APA
Australia's energy infrastructure partner

SIB Projects Business Case

Roma to Brisbane Gas Pipeline Access Arrangement 2028–32

29 May 2026

Contents

1. Overview

Number/ identifier	A-6_SIB Projects
Description of Issue/ Project	This business case covers a coordinated package of **stay-in-business capital projects** required to maintain the safe, reliable and compliant operation of the Roma to Brisbane Pipeline (RBP). These works address ageing electrical; mechanical and instrumentation assets located at above-ground facilities and associated compounds. The SIB program ensures that degraded or obsolete assets are replaced before they compromise pipeline integrity, safety, operability, or regulatory compliance.
Options considered	Two strategic options were assessed for managing ageing facility assets: **Option 1 — Run to Failure / Do Nothing** Under this approach, assets remain in service until they degrade to the point of failure or become unrepairable due to OEM obsolescence. This results in: • Increased safety and reliability risks • Higher likelihood of unplanned outages • escalating corrective maintenance costs • Potential non-compliance with regulatory and licence obligations **Option 2 — Planned Proactive Replacement (Preferred)** This option involves a targeted, risk-based replacement and upgrade program designed to maintain: • Safety • Operational reliability • Access to spare parts and technical support • Compliance with relevant standards and licence conditions This option represents prudent and efficient asset stewardship.
Proposed Solution	The preferred solution is **Option 2**, as it appropriately balances cost, safety, operational reliability, and regulatory compliance. It avoids the increasing risks associated with equipment deterioration, including the potential for regulatory breaches and loss of operating licence if critical equipment fails.
Estimated Cost	$3.49 million
Relevant standards	The SIB program ensures compliance with key standards and licence requirements, including: • **AS 2885.3 – Pipelines: Gas and Liquid Petroleum – Operations and Maintenance** • **RBP Pipeline Licence** These standards require operators to maintain safe and reliable facilities, manage risks to ALARP, and proactively address emerging asset integrity issues.

Stakeholder Engagement	• Scope discussed during RBP Access Arrangement Stakeholder Meetings #3 (25/11/2025); #4 (10/02/2026); and #5 (31/03/2026)
Consistency with National Gas Rules (NGR)	The proposed SIB projects comply with **NGR Rule 79** because the expenditure: • **Is necessary** to maintain and improve safety and service integrity (79(2)(c)(i)–(ii)) • **Reflects what a prudent service provider** would undertake, acting efficiently and in line with good industry practice (79(1)(a)) • **Achieves the lowest sustainable cost** of providing pipeline services through proactive rather than reactive intervention Together, these projects maintain essential operational capability and ensure the RBP continues to provide safe, reliable service to customers.

2. Program details

2.1. Background

Stay-in-business (SIB) capital expenditure on the RBP focuses on maintaining the long-term safety, reliability, and integrity of pipeline facilities so they remain fit-for-purpose throughout their operational life. The SIB program covers a diverse portfolio of **electrical, mechanical, and instrumentation upgrades and replacements** across above-ground facilities and associated compounds. These works are identified through routine inspections, condition assessments, and performance data, and delivered through planned refurbishment cycles.

For the 2028–32 Access Arrangement period, the following assets have been identified as requiring targeted upgrades:

- SEA valve replacements
- Replacement crane truck
- Kogan Scraper Station DEA & Changeover panel upgrade
- Shutdown Valve (SDV) at Condamine
- Woodroyd, Arubial and Scotia Obsolete SDV over pressure devices
- Dalby CS control room footings
- Ellengrove Reliability Project

Each of these items is assessed in detail in Sections 3 to 8.

2.2. Assessment of options

Two strategic management approaches were considered:

Option 1 — Accept Non-Conformance and Allow Assets to Fail

This option would allow deterioration to continue unchecked, replacing or repairing assets only when failure occurs. This approach results in:

- Higher operational and safety risks
- Increased likelihood of regulatory non-compliance
- Unpredictable, lumpy, and typically higher unplanned expenditure
- Potential loss of operating licence

Given the age of the assets and limited OEM support, this option is inefficient and imprudent.

Option 2 — Planned Proactive Replacement and Upgrades (Preferred)

This option maintains an appropriate level of work to ensure reliable ongoing operation, including proactive refurbishment, replacement, and condition-based maintenance. Benefits include:

- Predictable and efficient expenditure profiles
- Reduced risk of unplanned outages
- Improved safety and compliance
- Efficient use of resources by coordinating works across sites

Planned intervention is clearly the prudent, efficient approach aligned with good industry practice.

2.2.1. Inherent Risk assessment

A detailed risk assessment has been undertaken for each of the individual SIB project items outlined in Sections 3 to 8 of this business case. These assessments evaluate health and safety, operational, compliance, reputational, environmental and financial risks using APA's Enterprise Risk Matrix. The inherent (untreated) risks identified for the assets, when no action is taken, range from **Moderate to High**, reflecting the combined effects of asset ageing, OEM obsolescence, and increasing maintenance requirements. [

Overall, the collective inherent risk profile of the SIB assets—if left unaddressed under Option 1—results in a **HIGH untreated risk rating**, driven primarily by the potential for regulatory non-compliance, increased likelihood of equipment failure, and elevated safety and operational risks. The project-specific assessments presented in Sections 3–8 demonstrate that proactive renewal (Option 2) reduces these risks to **Low or Negligible** by addressing foreseeable failures, improving reliability, and ensuring assets remain compliant with licence and standard requirements.

This confirms that a planned, proactive SIB program is required to reduce risks to ALARP and maintain the safe and reliable operation of the RBP.

Financial assessment

A consideration of the pros and cons of the expected financial outlays for both options is shown below. Given end-of-life replacement and rectification costs are inevitable, this business case demonstrates that the proposed expenditure is efficient and appropriate to manage the associated risks.

Table 2-1: Financial assessment for the Facilities business case

	Commentary
Option 1: Accept non-conformance with regulations and asset failure	• Unplanned approach to replacements and rectification leads to lumpy and more unpredictable expenditure. • Replacements are more expensive given the efficiency losses (costs and staff/contractor resources) of unplanned works compared to planned works. • Expenditure grows significantly once the level of failures exceeds the capacity of staff resources –significant increased costs for contractors to be on stand-by. • Avoided costs in the earlier years are more than offset by regulatory fines and the financial costs and penalties arising from reputational damage, legal action and the loss of the RBP operating licence.
Option 2: Planned approach to managing risks and costs	• Where possible, replacements take place with other works at the site, improving cost and resource efficiency. • Steady replacement rate over the coming years gives predictability in expenditure. • Expect a reduction in some costs over time ahead of reaching a stabilised level of expenditure.

The risk and financial assessments above support the preferred option (option 2) as appropriately balancing costs and risks.

2.3. Consistency with the National Gas Rules and other regulations

The SIB program satisfies the **NGR Rule 79** capital expenditure criteria because it:

- **Is necessary** to maintain safety and integrity of services (79(2)(c)(i)–(ii))
- **Reflects prudent and efficient expenditure** expected of a responsible asset manager (79(1)(a))

- **Aligns with good industry practice**, particularly AS 2885 and electrical/mechanical integrity standards
- Ensures compliance with the RBP Pipeline Licence and legislative obligations

Most works will be delivered by APA field resources, with external contractors engaged following APA Procurement Policy requirements where specialised skills are necessary.

2.4. Proposed costs for FY28-FY32

This includes the planned expenditure on all projects listed in Sections 3 to 8. A full breakdown is included in Table 2-3 of the source document.

Table 2–3 Total cost for SIB business case ($'000s Real 2026-27)

Description	FY28	FY29	FY30	FY31	FY32	Total
Lytton Valve replacement DN300 & DN200	-	-	-	116	117	233
Replacement for Crane truck	-	289	-	-	-	289
Generator Upgrades	-	-	-	116	117	233
SDV at Condamine	-	-	116	-	-	116
Woodroyd, Arubial & Scotia Actuators	-	-	58	58	58	174
Dalby CS control room footings	-	116	-	-	-	116
Ellengrove Reliability	-	-	-	2,327	-	2,327
FY Totals	0	404	174	2,618	292	3,488

3. SEA valve replacements

3.1. Project objective and scope

The objective of this project is to replace ageing DN300 and DN200 valves at Lytton to ensure continued safe operation, reliable isolation capability, and compliance with AS 2885 requirements for pipeline integrity. These valves form part of the broader isolation and protection system along the RBP and must remain operable to allow APA to respond effectively to maintenance needs and abnormal operating conditions.

The project scope includes removal of existing valves, installation of new DN300 and DN200 isolation valves, and all associated mechanical, civil, and commissioning activities.

3.2. Background

The affected valves were installed as part of older pipeline infrastructure and have reached a point where replacement is required to maintain system integrity. As with many legacy assets along the RBP, age-related deterioration and limitations in spare-parts availability increase the risk of valve malfunction or inability to isolate the pipeline when required.

These risks cannot be effectively mitigated through in-service maintenance alone, given the safety, operational and compliance requirements associated with isolation equipment.

3.3. Assessment of options

The options considered for the access arrangement period are:

— Option 1: Do nothing

— Option 2: Replace valves identified as passing

3.3.1. Risk assessment

The risk is being unable to positively isolate sections of the station due to passing valves. Preventing other station works from happening due to the isolation issues.

Table 3–1: Risk assessment – SEA Valve Replacement

Risk Area	Potential Impact	Option 1:		Option 2:	
		Likelihood / Impact	Inherent risk rating	Likelihood / Impact	Risk rating
Health & Safety	Exposure to fugitive emissions	Frequent / Minimal	Low	Remote / Minimal	Negligible
Environment	Impacting Site	Frequent / Minimal	Low	Remote / Minimal	Negligible
Operational	n/a	n/a	n/a	n/a	n/a
People	n/a	n/a	n/a	n/a	n/a
Compliance	Regulatory breach	Frequent / Minor	Moderate	Remote / Minor	Negligible
Reputation & Customer	Adverse media	Occasional / Significant	Moderate	Remote / Significant	Low
Financial	n/a	n/a	n/a	n/a	n/a
Untreated risk			**MODERATE**		**LOW**

Option 1 – Do Nothing

Leaving the valves in service without planned replacement significantly increases the likelihood of valve failure. Continued degradation may limit isolation capability during emergencies or maintenance activities (such as in line inspection (ILI)), exposing APA to non-compliance with AS 2885.3 and the RBP Pipeline Licence.

While this option defers expenditure, it materially increases:

- the risk of uncontrolled gas release
- unplanned outages
- higher-cost emergency remediation
- safety and reputational impacts

Option 1 is not technically acceptable or consistent with prudent pipeline operation.

Option 2 – Replace DN300 & DN200 Valves (Preferred)

This option involves planned replacement of the valves to ensure reliable pipeline isolation and long-term integrity. This is the only credible and practicable option, consistent with good industry practice and APA's obligations under:

- AS 2885.3 – Operations and Maintenance
- the RBP Pipeline Licence

Replacing the valves proactively ensures continued compliance and avoids the substantially higher costs and risks associated with managing valve failures.

3.3.2. Financial assessment

End-of-life replacement and rectification costs are inevitable, so the significant question is how the spend should be balanced to appropriately manage the associated risks.

Table 3–2: Financial assessment – Replace Valves ($ Real 30 June 2026)

	Commentary
Option 1: **Change nothing**	• A qualitative financial assessment demonstrates that: • **Option 1 (Do Nothing)** results in unpredictable, potentially very high lifecycle costs due to emergency repairs, safety risks, and possible regulatory penalties.
Option 2: **Replace DN300 & DN200 Valves at Lytton**	• **Option 2 (Replace Valves)** enables efficient planning, coordination with other site works, and greatly reduces overall lifecycle risk and cost exposure. • Accordingly, Option 2 delivers the **lowest sustainable cost** over the asset life.

The preferred option that we believe appropriately balances costs and risks is the programmed replacement of the identified valves.

3.4. Proposed costs for FY28-FY32

Replacement of the DN300 and DN200 Lytton valves is planned for **FY31–FY32**.

These activities will be delivered using APA resources and specialist contractors where required, consistent with APA's Procurement Policy.

Table 3–3: Estimated annual cost to Replace Valves ($'000s June 2026-27)

Description	FY28	FY29	FY30	FY31	FY32	Total
Lytton Valve replacement DN300 & DN200	-	-	-	116	117	233

4. Replacement Crane truck

4.1. Project objective and scope

The objective of this project is to replace the existing crane truck used to support routine and reactive maintenance activities on the RBP. The crane truck is essential for safely transporting, lifting, and installing heavy equipment—particularly at cathodic protection (CP) sites and locations requiring electrical or mechanical repairs.

The replacement truck will enable APA to continue meeting operational, safety, and compliance requirements by ensuring maintenance activities can be undertaken efficiently and in accordance with relevant standards.

4.2. Background

APA relies on crane-equipped vehicles to transport and install CP units, electrical components, and other heavy infrastructure necessary for maintaining pipeline integrity. The current truck will exceed 20 years of age during this access arrangement and is now reaching the end of its serviceable life.

As with other CP and facility assets described in the business case, several factors drive the need for replacement:

- Increasing component failures due to age
- Difficulty sourcing spare parts for older equipment
- Rising maintenance and reliability risks
- Dependency on crane capability for safe installation of CP units and other site infrastructure

Given the long lead time for procuring replacement vehicles and the criticality of crane-assisted tasks, timely renewal is necessary to maintain field readiness and avoid delays in integrity-related work.

4.3. Assessment of options

The options considered for the access arrangement period are:

— Option 1: Do nothing,

— Option 2: Replace crane truck with a compliant vehicle

4.3.1. Risk assessment

Failing to update the Crane Truck may result in:

- CP system could have delayed maintenance as no flexibility to complete in house.
- Emergency response times delayed.
- Erosion repairs delayed maintenance as no flexibility to complete in house.
- Pigging gear transport cost absorbed by new truck.

Table 4–1: Risk assessment – Crane Truck Replacement

Risk Area	Potential Impact	Option 1 :		Option 2:	
		Likelihood / Impact	Inherent risk rating	Likelihood / Impact	Risk rating
Health & Safety	n/a	n/a	n/a	n/a	n/a
Environment	n/a	n/a	n/a	n/a	n/a
Operational	Disruption 1-3 months	Frequent / Minimal	Low	Remote / Minimal	Negligible
People	n/a	Frequent / Minor	Moderate	Remote / Minor	Negligible
Compliance	Regulatory breach	Frequent / Minor	Moderate	Remote / Minor	Negligible
Reputation & Customer	n/a	n/a	n/a	n/a	n/a
Financial	n/a	n/a	n/a	n/a	n/a
Untreated risk			**MODERATE**		**NEGLIBIBLE**

4.3.2. Option 1

Under this option, the current crane truck remains in service beyond its effective operational life until the point of terminal failure. This approach introduces several risks:

- Increased potential for breakdowns
- Reduced ability to perform CP and electrical upgrades safely
- Higher maintenance expenditure
- Operational delays due to unavailability of lifting equipment
- Non-compliance with safe-work requirements if equipment reliability degrades

Option 1 exposes APA to increased safety, operational and financial risk, and is not aligned with prudent asset management.

4.3.3. Option 2

Option 2 involves replacing the crane truck as part of the planned SIB program. Benefits include:

- Ensures safe and efficient installation of CP units and associated equipment
- Reduces risk of work delays arising from vehicle or lifting-device failure
- Minimises maintenance costs associated with ageing equipment
- Supports compliance with AS 2885, electrical safety requirements, and APA's internal operating procedures
- Reduce on-road incident risks for both APA staff and the public due to inclusions of modern safety aids.

This option is consistent with good industry practice, particularly given the reliance on crane-assisted installations across the pipeline system.

Financial assessment

Table 4–2: Financial assessment – Crane Truck Replacement ($ Real 30 June 2026)

	Commentary
Option 1: Change nothing – continue to maintain old truck and engage contractors	• Defers capital expenditure in the short term but results in higher whole-of-life costs due to increasing breakdowns and reactive maintenance. • Increased reliance on external contractors leads to higher unit costs, mobilisation expenses, and reduced scheduling flexibility. • Unplanned failures risk delays to critical CP, electrical, and integrity works, increasing indirect operational costs. • Maintenance expenditure becomes unpredictable and lumpy, reducing cost efficiency over time. • Exposes APA to escalating costs associated with emergency response and loss of internal capability.
Option 2: Purchase new fit for purpose truck	• Requires upfront capital investment but delivers lower and more predictable lifecycle costs. • Enables continued use of internal resources, avoiding contractor premiums and repeated mobilisation costs. • Supports efficient planning by coordinating lifting capability with scheduled maintenance activities. • Reduces ongoing maintenance and downtime costs associated with ageing equipment. • Represents the lowest sustainable cost option when whole-of-life costs and risk exposure are considered. • Provides a safer truck for staff and other road users

The preferred option that appropriately balances costs and risks is the replacement of the Crane Truck.

4.4. Proposed costs for FY28-FY32

The cost reflects procurement of the vehicle and associated crane equipment. The work will be undertaken by APA, with the vehicle supplied in accordance with APA's Procurement Policy.

Current quotes have been supplied by APA approved vendors for the various components to assemble the new fit for purpose truck, these include:

- Isuzu Cab Chassis
- Tilt Tray, Utility Crane and miscellaneous equipment

Table 4–3: Estimated annual cost of CP unit upgrades ($'000s Real 2026-27)

Description	FY28	FY29	FY30	FY31	FY32	Total
Replacement for Crane truck		289				**289**

5. Kogan Scraper Station DEA and Changeover panel upgrade

5.1. Project objective and scope

The objective of this project is to restore reliable and compliant **backup electrical power** to the Kogan Scraper Station by replacing the ageing **Diesel Engine Alternator (DEA)** and **Automatic Transfer Switch (ATS) changeover panel**.

These assets provide critical standby power capability required to maintain essential functions during mains supply failures, support operational safety systems, and ensure compliance with electrical standards.

The project scope includes:

- Replacement of the existing 250 kVA DEA
- Replacement of the obsolete ATS/changeover panel
- Integration and commissioning of new compliant equipment
- Rectification of existing safety and electrical compliance deficiencies

5.2. Background

The existing DEA and ATS panel have reached end-of-life and present multiple operational, reliability and compliance risks:

- The DEA installation was added in the late 1980s when compression was added at Kogan station and has not been fully operational since **2019**, with only short no-load test runs possible, creating uncertainty about its ability to supply power during an outage.
- Key ATS components — the Automatic Mains Failure (AMF) module and control PCB — are **no longer available**, limiting maintainability.
- Multiple safety and electrical compliance issues exist, including:
    - No mechanical interlock between mains and generator
    - No power isolation on the panel
    - Exposed conductors
    - Inadequate segregation between control and LV circuits

While the generator setup at this site was under evaluation for decommissioning, the new Kogan – Brigalow pipeline that will supply the CS Energy operated Brigalow Peaking Power Plant starts from the APA Kogan station. This has resulted in an increased criticality of the Kogan site and warranted the continued presence of a backup generator for operational resilience. Once any changes are made to the installation it needs to be fully complaint to AS 3000 wiring rules. Assessment of options

The options considered for the access arrangement period are:

— Option 1: Do nothing

– Option 2: Replace the existing DEA and ATS changeover panel with modern, compliant units

5.2.1. Risk assessment

Operating an ageing, unreliable, and non-compliant backup generator presents the following risks:

- **Health & Safety:** Exposure to electrical hazards due to lack of isolation and exposed conductors.
- **Operational:** Significant risk of outage impacts if the DEA fails during critical conditions.

- **Compliance:** Non-compliance with electrical standards and RBP Licence obligations.
- **Financial:** Increased maintenance costs, extended downtime, and potential regulatory penalties.

With replacement (Option 2), risks reduce to **Low or Negligible** across all areas.

Table 5–1: Risk assessment – DEA & ATS replacement

Risk Area	Potential Impact	Option 1 :		Option 2:	
		Likelihood / Impact	Inherent risk rating	Likelihood / Impact	Risk rating
Health & Safety	Injury	Unlikely / Significant	Moderate	Remote / Significant	Low
Environment	n/a		n/a	n/a	n/a
Operational	Disruption 1-3 months	Unlikely / Minimal	Negligible	Remote / Minimal	Negligible
People	n/a		n/a	n/a	n/a
Compliance	Regulatory breach	Unlikely / Minor	Low	Remote / Minor	Negligible
Reputation & Customer	n/a		n/a	n/a	n/a
Financial	n/a	n/a	n/a	n/a	n/a
Untreated risk			**MODERATE**		**NEGLIGIBLE**

Option 1

The ‘Do Nothing’ option increases the risk that the DEA will fail during critical operations.

Under this option, the current DEA and ATS remain in service despite their degraded condition.

Consequences include:

- High likelihood of generator failure during a mains outage
- Safety hazards associated with non-compliant electrical equipment
- Inability to repair or maintain ATS components due to obsolescence
- Reduced operational capability and increased reliance on temporary measures
- Elevated regulatory and licence compliance risk

This option is not technically acceptable or aligned with prudent asset management.

Option 2

This option involves replacing both the DEA and ATS panel with modern, compliant equipment.

Benefits include:

- Restored and reliable backup power capability

- Elimination of safety and compliance defects
- Resolution of parts-obsolescence risks
- Support for future operational demands and system expansion
- Improved maintainability and vendor support

Option 2 is the only prudent option and is fully aligned with APA's electrical safety obligations and good industry practice.

Financial assessment

Table 5–2: Financial assessment – DEA & ATS replacement ($ Real 30 June 2026)

	Commentary
Option 1: Change nothing	• Short-term capital deferral only. • Long-term cost increases due to emergency failure, temporary supply solutions, and compliance breaches. • Risk of reputational and regulatory impacts far outweighs avoided CapEx
Option 2: Replace DEA and ATS (Preferred)	• Replacement occurs in a controlled, planned manner. • Enables bundling with other site work for efficiency. • Provides predictable expenditure and ensures long-term compliance.

The preferred option that appropriately balances costs and risks is Option 2, replacing existing DEA and ATS changeover panel.

5.3. Proposed cost for FY28-FY32

The DEA and ATS replacement is planned over FY31–FY32.

Work will be completed using a combination of APA resources and specialist electrical contractors, procured in accordance with APA's Procurement Policy.

Table 5–3: Estimated yearly cost of DEA & ATS replacement ($'000s Real 2026-27)

Description	FY28	FY29	FY30	FY31	FY32	Total
Generator Upgrades				116	117	**233**

6. Shutdown Valve (SDV) at Condamine

6.1. Project objective and scope

The objective of this project is to replace two safety critical Shutdown Valves (SDV 901A and 901B) at Condamine to address reliability issues, eliminate operational impairments, and ensure adequate protection against **overpressure events** on the DN400 section between Wallumbilla and Condamine due to the different maximum operating pressure west of Condamine compared to that east of Condamine.

The scope includes installation of two new SDVs with **integrated gas filtration**, replacement of contaminated or degraded components, required control upgrades, and commissioning. The replacement valves will restore reliable isolation and protection capability, in line with AS 2885 performance requirements.

6.2. Background

The SDV 901A/B manifold has become **contaminated with debris** from process gas, which has significantly reduced operational reliability and compromised protection functionality.

Key issues identified include:

- SDVs can be **closed only once**, requiring manual technician intervention before re-use
- Each activation requires an safety system impairment that carries a “moderate” risk assessment
- Long lead times (12–16 weeks) for critical parts
- Specialist Rotork expertise is required but minimally available in Australia

These deficiencies reduce operational flexibility, increase maintenance burden, and elevate the risk of delayed or inadequate response to abnormal operating conditions.

The RBP is the **sole gas supply route** to homes and businesses across major SEQ population centres (Brisbane, Gold Coast, Ipswich, Toowoomba, northern NSW), making reliable protection equipment essential from a system-wide security-of-supply perspective.

6.3. Assessment of options

The options considered for the access arrangement period are:

- Option 1: Change nothing – risk of overpressure incident between Wallumbilla & Condamine
- Option 2: Install 2 new valves with gas filtration

6.3.1. Risk assessment

The inherent risks of retaining the current SDVs include:

- **Operational:** delayed or failed shutdown during an overpressure event
- **Compliance:** inability to meet AS 2885 protection system requirements
- **Safety:** increased risk of uncontrolled pressure excursions
- **Financial:** cost and delays associated with long lead times and unplanned outages

With replacement, residual risks fall to **Negligible**, consistent with ALARP expectations.

Table 6–1: Risk assessment – Shutdown Valve at Condamine

Risk Area	Potential Impact	Option 1 :		Option 2:	
		Likelihood / Impact	Inherent risk rating	Likelihood / Impact	Risk rating
Health & Safety	Fatality	Occasional / Major	High	Remote / Minor	Negligible
Environment	n/a		n/a	n/a	n/a
Operational	Disruption 1-3 months	Occasional / Minor	Low	Remote / Minor	Negligible
People	n/a	n/a	n/a	n/a	n/a
Compliance	n/a	n/a	n/a	n/a	n/a
Reputation & Customer	Adverse local media	Occasional / Minor	Low	Remote / Minor	Negligible
Financial	Revenue Impact <$1M	Occasional / Minor	Low	Remote / Minor	Negligible
Untreated risk			**HIGH**		**NEGLIGIBLE**

Option 1

Under this option:

- SDVs remain unreliable and require constant manual intervention
- Protection function remains impaired, increasing the risk of overpressure
- Operations staff continue to experience reduced ability to respond
- Long specialist lead times increase the risk of extended outages
- Risk profile remains “Moderate” even under best-effort maintenance

This option is not acceptable technically, nor consistent with AS 2885 obligations or prudent pipeline practice.

Option 2

Replacing the valves with modern units incorporating gas filtration:

- Eliminates contamination issues
- Restores valve reliability and protection functionality
- Reduces impairments and operational delays
- Fully mitigates the risk of overpressure events
- Provides long-term maintainability and alignment with OEM support

This approach significantly reduces safety, operational, and compliance risks and delivers predictable performance consistent with good industry practice.

6.3.2. Financial assessment

Table 6–2: Financial assessment – Shutdown Valve at Condamine ($ Real 30 June 2026)

	Commentary
Option 1: Change nothing – risk of overpressure incident between Wallumbilla & Condamine	• Lower short-term cost but exposes APA to higher long-term costs • Potential regulatory and reputational penalties due to reliability issues • Increased Opex from ongoing impairments and technician interventions
Option 2: Install 2 new SDVs	• Enables coordinated installation and testing • Provides predictable Capex • Reduces lifecycle costs by eliminating emergency response and high-risk operational exposure

The preferred option that appropriately balances costs and risks is Option 2, Install 2 new valves with gas filtration

6.4. Proposed cost for FY28-FY32

The estimated cost for the SDV replacement at Condamine is:

$100,000 in FY30 (Real $2026)

This includes supply and installation of valves and contractor support for configuration and commissioning.

All procurement will comply with APA's Procurement Policy.

Table 5–3: Annual estimated cost SDV replacement ($'000s Real 2026-27)

Description	FY28	FY29	FY30	FY31	FY32	Total
SDV at Condamine			116			**116**

7. Woodroyd, Arubial and Scotia Obsolete SDV over pressure devices

7.1. Project objective and scope

The objective of this project is to restore reliable over-pressure protection capability at the Arubial, Woodroyd, and Scotia sites by replacing obsolete Bettis Over-Pressure Pilot Control Valves with modern, supported alternatives using conversion kits.

The scope includes:

- Installation of conversion kits on all affected pilot control valves
- Integration and commissioning of the new pilot control assemblies
- Staged implementation across all three sites to align with operational and maintenance schedules

This work is required to ensure valves can return to service following an over-pressure event and continue to perform essential emergency shutdown (ESD) functions.

7.2. Background

Recent Emergency Shut Down (ESD) testing at Arubial confirmed that while the pilot control valves still operate, the installed Bettis units are now obsolete, and replacement parts are no longer manufactured.

The supplier, Pacific Controls, has advised:

- The valves are no longer available from the supplier
- New alternatives must be sourced
- Expected lead time for replacements is up to 25 weeks

These obsolete pilot control valves are also installed at Woodroyd and Scotia, exposing all three sites to the same reliability, safety, and maintainability issues.

Continued operation of unsupported pilot valves creates a risk that:

- Valves cannot return to service after an over-pressure event
- Over-pressure protection performance degrades
- APA may be unable to complete scheduled ESD tests
- Operational response capability is impaired

Given the critical safety function of these valves, proactive replacement is essential.

7.3. Assessment of options

The options considered for the access arrangement period are:

— Option 1: Change nothing – unable to return to service after an overpressure event

– Option 2: Install conversion kits to restore valves to intended operability

7.3.1. Risk assessment

Option 1 (Do Nothing):

- **Health & Safety:** Increased risk due to unreliable over-pressure response
- **Operational:** Up to 1–3 months service disruption if valves cannot be returned to operation
- **Compliance:** Potential breach of licence and AS 2885 testing requirements

- **Financial:** Higher long-term repair and emergency response costs

Option 2 (Preferred):

- Residual risks reduce to **Negligible** across all categories
- Ensures ongoing operability and protection capability

Table 7–1: Risk assessment – obsolete pilot control valves

Risk Area	Potential Impact	Option 1 :		Option 2:	
		Likelihood / Impact	Inherent risk rating	Likelihood / Impact	Risk rating
Health & Safety	Fatality	Occasional / Major	High	Remote / Minor	Negligible
Environment	n/a		n/a	n/a	n/a
Operational	Disruption 1-3 months	Occasional / Minor	Low	Remote / Minor	Negligible
People	n/a	n/a	n/a	n/a	n/a
Compliance	n/a	n/a	n/a	n/a	n/a
Reputation & Customer	Adverse local media	Occasional / Minor	Low	Remote / Minor	Negligible
Financial	Revenue Impact <$1M	Occasional / Minor	Low	Remote / Minor	Negligible
Untreated risk			**HIGH**		**NEGLIGIBLE**

Option 1

If APA continues using the existing Bettis pilot control valves:

- Valves may **fail to return to service** following an over-pressure event
- Spares are unobtainable, preventing future repairs
- APA may be **unable to complete ESD testing**
- Reliability of over-pressure protection decreases over time

While this option defers capital expenditure, it is not technically acceptable and is inconsistent with prudent pipeline safety obligations.

Option 2

Option 2 involves replacing the obsolete Bettis pilot control valves with modern, supported devices via **conversion kits**, implemented through a staged upgrade across the three affected sites.

Benefits include:

- Restores full and reliable over-pressure protection
- Ensures valves can return to service after activation

- Eliminates spares and obsolescence risk
- Allows upgrades to align with other planned maintenance, improving efficiency
- Ensures long-term vendor support and maintainability

This option represents prudent, efficient asset management consistent with AS 2885 principles and APA's operational requirements.

The preferred option that appropriately balances costs and risks is Option 2, install a suitable conversion kit to the existing valves.

7.3.2. Financial assessment

A qualitative financial comparison shows:

- **Option 1** appears cheaper initially but ultimately results in higher costs from failures, emergency interventions, and compliance risks.
- **Option 2** enables efficient, predictable expenditure by integrating replacements with other site works.

Given that obsolescence makes repair impractical and unreliable, Option 2 is the prudent and efficient choice under NGR 79.

Table 7–2: Financial assessment – obsolete pilot control valves ($ Real 30 June 2026)

	Commentary
Option 1: Change nothing – unable to return to service after overpressure event	• Defers immediate capital expenditure but results in higher long-term costs due to increased likelihood of valve failure and emergency response. • Inability to source spare parts leads to extended outages and reliance on temporary or manual workarounds. • Emergency repairs and unplanned interventions are more expensive and less efficient than planned upgrades. • Increased risk of non-compliance may expose APA to regulatory, reputational, and remediation costs. • Whole-of-life costs are higher due to reactive maintenance and elevated operational risk.
Option 2: Install conversion kit to existing valves	• Requires planned capital expenditure but delivers lower whole-of-life cost by avoiding emergency failures. • Enables efficient, scheduled works that can be bundled with planned maintenance activities. • Eliminates obsolescence-related costs by restoring access to supported components and vendor support. • Reduces likelihood of outages and associated economic and operational disruption costs. • Represents the lowest sustainable cost option when risk, reliability, and lifecycle considerations are included.

7.4. Proposed cost for FY28-FY32

Total proposed investment is for installation of conversion kits across Arubial, Woodroyd and Scotia:

Works will be delivered by APA field teams with specialist vendor support where required, in accordance with APA's Procurement Policy.

Table 5–3: Annual estimated cost of obsolete pilot control valves ($'000s Real 2026-27)

Description	FY28	FY29	FY30	FY31	FY32	Total
Arubial Actuators			58	58	58	**174**

8. Dalby CS control room footings

8.1. Project objective and scope

The objective of this project is to **restore structural integrity and operational functionality** of the Dalby Compressor Station (CS) control room building by re-levelling the existing footings and implementing a longer-term engineering solution to prevent recurring subsidence.

The scope includes:

- Engaging a specialist local contractor to re-level the building
- Engaging a qualified civil engineer to assess and design a long-term corrective solution (e.g., installation of adjustable stumps)
- Implementing required structural works to restore safe access, maintain security, and ensure proper operation of fire-system control measures

These works are essential to maintain building usability and ensure the control room continues to support safe compressor station operations.

8.2. Background

The Dalby CS control room building has experienced ongoing movement since its construction in 2012, due to the highly reactive local soil conditions. After more than a decade of extreme weather variations, the footings have shifted to the point where:

- Control room doors may soon be unable to close, compromising site security
- Misalignment may interfere with fire-system pressurisation requirements
- Operational access and use of the control room may be impaired

Recent inspection and laser-level measurements identified:

- Height variances of up to 45 mm across the foundation
- Up to 25 mm differential over a 2.5 m span
- The largest deviations occurring beneath the rear control room door

Without intervention, further movement will compromise building function and safety controls critical for compressor operations.

8.3. Assessment of options

The options considered for the access arrangement period are:

— Option 1: Change nothing – Unable to use Dalby Compressor

— Option 2: Level the control room building

8.3.1. Risk assessment

Risks assessed are

Table 8–1: Risk assessment – Dalby CS control room footings

Risk Area	Potential Impact	Option 1 :		Option 2:	
		Likelihood / Impact	Inherent risk rating	Likelihood / Impact	Risk rating
Health & Safety	Injury	Unlikely / Significant	Moderate	Rare / Significant	Negligible

Environment	n/a	n/a	n/a	n/a	n/a
Operational	Disruption 1-3 months	Unlikely / Significant	Moderate	Rare / Significant	Negligible
People	n/a	n/a	n/a	n/a	n/a
Compliance	n/a	n/a	n/a	n/a	n/a
Reputation & Customer	Adverse National media	Unlikely / Significant	Moderate	Rare / Significant	Negligible
Financial	Revenue Impact <$1M	Unlikely / Minor	Low	Remote / Minor	Negligible
Untreated risk			**MODERATE**		**NEGLIGIBLE**

Option 1

Choosing not to address the footing movement results in:

- **Fire system malfunction**, as pressurisation may not operate correctly
- **Security risks**, since the control room door may not close
- Eventual inability to use the Dalby Compressor Station control room

Although Option 1 avoids immediate capital expenditure, it exposes APA to safety, compliance, and operational risks that are unacceptable for a critical facility.

Option 2

This option restores the control room to correct elevations and ensures long-term structural stability.

Key benefits include:

- Restores full control-room functionality, including fire-system integrity
- Ensures reliable and secure door operation
- Reduces operational risk from foundation movement
- Uses proven local contract capability and specialist engineering design

This option addresses both immediate safety concerns and provides a sustainable long-term asset solution, consistent with prudent pipeline facility management and AS 2885 principles.

The preferred option that appropriately balances costs and risks is Option 2, Use local Contractor to level the Control Room building.

8.3.2. Financial assessment

Table 8–2: Financial assessment – Dalby CS Control Room footings

	Commentary
Option 1: Change nothing – unable to function effectively	• Defers immediate capital expenditure but leads to higher long-term costs as building condition continues to deteriorate. • Increases likelihood of emergency remediation, site access issues, and unplanned outages affecting compressor station operations.

	• Ongoing movement may compromise fire-system performance and site security, resulting in costly compliance rectification. • Reactive repairs are less efficient and more expensive than planned structural intervention. • Whole-of-life costs increase due to escalating risk, disruption, and potential loss of use of the control room facility.
Option 2: Level Control Room and Implement Long-Term Solution	• Requires planned capital expenditure but delivers lower whole-of-life cost by addressing root cause of footing movement. • Enables works to be undertaken in a controlled and efficient manner, reducing risk of emergency repairs. • Restores full functionality of the control room, avoiding future costs associated with security or fire-system non-compliance. • Improves predictability of expenditure and avoids repeated short-term fixes. • Represents the lowest sustainable cost option when lifecycle, risk, and operational impacts are considered.

8.4. Proposed cost for FY28-FY32

The cost is based on contemporary quotes from local contractors and includes both re-levelling and engineering design for a long-term solution.

Work will be performed by a combination of APA staff and specialist contractors engaged under APA's Procurement Policy.

Table 5–3: Annual estimated cost of satellite data loggers ($'000s Real 2026-27)

Description	FY28	FY29	FY30	FY31	FY32	Total
Dalby CS control room footings		116				**116**

9. Ellengrove Reliability

9.1. Project objective and scope

The objective of the Ellengrove Reliability project is to maintain the continuity and reliability of gas supply to the Brisbane metropolitan and Gold Coast load centres by addressing the loss of upstream system redundancy following recent network reconfiguration.

The project proposes the installation of a third pressure control and metering run at Ellengrove Station, providing sufficient on-site redundancy to enable continued operation in the event of a failure, maintenance activity, or impairment affecting one of the existing runs.

The scope of works includes:

- Design and installation of a third pressure control and metering run
- Associated piping, valving, instrumentation and control integration
- Modifications to civil foundations, structural steel, and station layout as required
- Integration with existing control and protection systems
- Commissioning and functional testing

These works restore effective redundancy at Ellengrove and ensure the station can continue to meet its critical system role under changed operating conditions.

9.2. Background

Ellengrove Station is the sole point of supply to the Brisbane metropolitan area and the Gold Coast, servicing a large and highly concentrated demand centre. The station was originally designed as a supplementary pressure supply point to the main supply being the original build Bellbird Park station.

The design of Ellengrove station with two pressure control runs (duty and standby) that were not wholly independent, with system-level redundancy provided through the original primary flow path via Bellbird Park.

Under recent and planned network changes — including the DN250 Supply Security Project — Bellbird Park will no longer be available as an alternate supply path. As a result, Ellengrove will operate without any external system redundancy, relying solely on the availability of its two internal runs.

While Ellengrove is currently performing as originally designed, the operating context has fundamentally changed. The loss of the alternative supply path materially increases the consequences of a failure or forced outage at Ellengrove. In the absence of additional on-site redundancy, a common-mode event or major failure affecting both runs would result in a loss of supply to Brisbane and the Gold Coast, with significant customer, reputational, and regulatory consequences.

An internal Ellengrove Reliability Review Summary Report assessed this changed risk profile and concluded that additional on-site redundancy is required to maintain system reliability at an acceptable level.

9.3. Assessment of options

The options considered for the access arrangement period are:

- Option 1: Do Nothing
- Option 2: Install a third pressure control and metering run (Preferred)

Risk assessment

Loss of supply at Ellengrove would have widespread impacts on gas customers across Brisbane and the Gold Coast. The risk assessment summarised in Table 9–1 shows that retaining the existing configuration exposes APA and customers to an unacceptable level of risk, while installation of a third run materially mitigates that exposure.

Table 9–1: Risk assessment – Ellengrove Reliability

Risk Area	Potential Impact	Option 1		Option 2	
		Likelihood / Impact	Inherent risk rating	Likelihood / Impact	Risk rating
Health & Safety	n/a	n/a	n/a	n/a	n/a
Environment	n/a	n/a	n/a	n/a	n/a
Operational	Disruption 1-3 months	Remote / Catastrophic	High	Rare / Catastrophic	Low
People	n/a	n/a	n/a	n/a	n/a
Compliance	n/a		n/a	/a	n/a
Reputation & Customers	Adverse media, negative feedback	Remote / Major	Moderate	Rare / Major	Low
Financial	n/a	Remote / Major	Moderate	Rare / Major	Low
Untreated risk			**HIGH**		**LOW**

9.3.1. Financial assessment

Table 9–2: Financial assessment – Install 3rd Metering Run ($ Real 30 June 2026)

	Commentary
Option 1: Change nothing	While Option 1 defers immediate capital expenditure, it does so at the cost of: • Increased exposure to high-consequence outage events • Potential emergency response and unplanned reinforcement costs • Elevated reputational and regulatory risk arising from loss of supply to major demand centres
Option 2: Install 3rd Run at Ellengrove	Option 2 involves a higher upfront capital investment but delivers: • Predictable, planned expenditure • Significantly reduced risk of unplanned outages • Lower expected lifecycle cost when risk exposure is taken into account

Option 1

Under this option, Ellengrove would continue to operate with two pressure control runs only, relying on internal redundancy alone following the removal of Bellbird Park as an alternate supply path.

This option:

- Accepts the increased consequence of a dual-run failure
- Provides no practical mitigation for common-mode failures, major maintenance, or latent defects
- Exposes customers to a prolonged loss of supply in the event of a major outage
- Increases reliance on emergency response measures rather than engineered controls

The inherent risk associated with this option is assessed as **High**, driven primarily by the scale of customer impact and the concentration of demand supplied through Ellengrove.

Option 1 is inconsistent with prudent asset management for a critical supply node and does not adequately manage foreseeable reliability risks.

Option 2

This option involves installing a third run at Ellengrove in line with the recommendations of the Ellengrove Reliability Review.

The additional run:

- Restores effective redundancy at the station level
- Allows maintenance or fault response on one run without materially increasing supply risk
- Significantly reduces the likelihood and consequence of a full station outage
- Improves the resilience of supply to major demand centres

The risk assessment (Table 9–1) demonstrates that Option 2 reduces the untreated operational risk rating from **High to Low**, bringing residual risk to a level consistent with ALARP principles and good industry practice.

Option 2 is the only option that credibly addresses the changed operating environment and the removal of upstream redundancy.

The preferred option that appropriately balances costs and risks is Option 2, Install 3rd metering run at Ellengrove

9.4. Proposed cost for FY28-FY32

The estimated cost of installing a third pressure control and metering run at Ellengrove is $2.0 million (Real $2026). This estimate is based on costs for comparable pressure control and metering upgrades on similar APA assets.

The expenditure is currently forecast in FY31, aligning with the completion of the DN250 Supply Security Project and the point at which Ellengrove becomes solely reliant on on-site redundancy.

Table 9–3: Annual estimated cost of Ellengrove Reliability project ($'000s Real 2026-27)

Description	FY28	FY29	FY30	FY31	FY32	Total
Ellengrove Reliability				2,327		**2,327**