September 2016

roma to brisbane pipeline

access arrangement submission.

attachment 5-2 – forecast capital expenditure project documents

business case

urban risk reduction

Business Case – Capital Expenditure

RBP Risk Mitigation - Protective Barriers and Pressure Regulation

Business Case Number AA-02 – REVISION 1

1 Project Approvals

TABLE 1: BUSINESS CASE – PROJECT APPROVALS

Prepared By	Jennifer Ward, *Pipeline and Asset Management Engineer, APA Group*
Reviewed By	Francis Carroll, *Engineering Services Manager Queensland, APA Group*
Approved By	Craig Bonar, *Manager East Coast Grid Engineering, APA Group*

2 Project Overview

TABLE 2: BUSINESS CASE – PROJECT OVERVIEW

Description of Issue/Project	The DN250, DN300 and DN400 metropolitan sections of the Roma Brisbane Pipeline (RBP) operate at risk levels that have become acceptable, due to urban encroachment. This risk is due to the threat of external interference in high consequence areas, causing damage to the pipeline, leading to potential rupture and resulting fatalities and injuries within the measurement length. It is of particular concern to the RBP due to its age and its construction which is less resistant to damage than modern pipelines. The AS 2885 safety management process requires APA to carry out an options study to reduce the risk to demonstrably ALARP where there have been land use changes around an existing pipeline. The ALARP study assessed a range of options and identified a preferred solution. As part of a long term strategy, operating pressure regulation is being implemented in addition to complementary protective barrier slabbing in identified critical areas in order to reduce the risk of pipeline rupture and improve public safety.
Options Considered	The following options have been considered: 1. Option 1: Do Nothing Option – retain the existing unacceptable risk level 2. Option 2: MOP Reduction to fully meet code compliance for maximizing the critical defect length of the pipeline, by installing additional regulating stations upstream of the metropolitan area and additional compression in the metro area to maintain supply; 3. Option 3: Pipe Replacement – total replacement of non-compliant pipe with modern pipe, meeting the code requirements for damage resistance, in the metropolitan area [metro looping] in combination with pressure reduction or abandonment of original line; 4. Option 4: Physical protection - Increased physical protection by the installation of barriers such as concrete slabs, encasement or similar, at all locations accessible by excavators and augers in the high consequence areas. This does not achieve the 'no rupture' or energy release rate code requirements but reduces the likelihood of mechanical damage occurring. 5. Option 5: Procedural measures only – increased patrol frequency; signage; landowner and 3rd party liaison; APA considers that all effective procedural measures are already in place and this would have limited additional effectiveness. 6. Option 6 (preferred): Combined MOP reduction and physical protection – combination of option 2 and 4, where the preference is to undertake MOP reduction where feasible, as it removes the highest consequence (rupture) and is generally more cost effective. Where MOP reduction is impractical, physical protection is to be installed to minimize the likelihood of mechanical damage. This option was the recommended outcome of the ALARP study.
Estimated Cost	$10.97 million

Consistency with the National Gas Rules (NGR)	The completion of this risk reduction work complies with the new capital expenditure criteria in Rule 79 of the NGR because: • it is necessary to maintain and improve the safety of services and maintain the integrity of services (Rules 79(2)(c)(i) and (ii)); and • it is such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services (Rule 79(1)(a)).
Stakeholder Engagement	The primary stakeholder consideration in this project is for landowner impacts from third party interference in urban encroachment areas. Other stakeholders are the Queensland Department of Natural Resources and Mines, Brisbane City Council and other local authorities, and APA's shippers on the RBP and commercial operations.

3 Background

3.1 Description of relevant pipeline

The RBP was constructed in 1969 to provide gas from the Roma Gas Fields to supply domestic and industrial consumers in Brisbane. The pipeline is approximately 440 km long and has been expanded since original construction to now consist of fully looped sections of DN250 and DN400 pipeline between Wallumbilla and Brisbane. The Brisbane metropolitan section of the RBP comprises a DN300 pipeline, partially duplicated for 6 km by the Metro Looping 1 (MLP1) project, and a DN200 pipeline supplying Gibson Island. There are also laterals to Swanbank power station and Lytton (Caltex) refinery.

In its determination for the 2012 to 2017 access arrangement the AER accepted the APA proposal in relation to the capacity expansion of the RBP. This expansion involved the installation of an additional compressor at the Dalby Compressor Station, duplication of a 6 km section of the Roma Brisbane Pipeline in the metro section and a MOP upgrade of the DN400 pipeline.

This project represented the first phase of the Metropolitan looping project (MLP1). At the time of the last AA submission APTPPL noted that the capacity of the RBP is likely to be constrained at some point by the capacity of the metro section and there would be a need to construct metro looping phase 2 and 3. Had this project gone ahead the additional capacity provide by the looping would have permitted a pressure reduction on the current metro section whilst still meeting the capacity needs of Brisbane users.

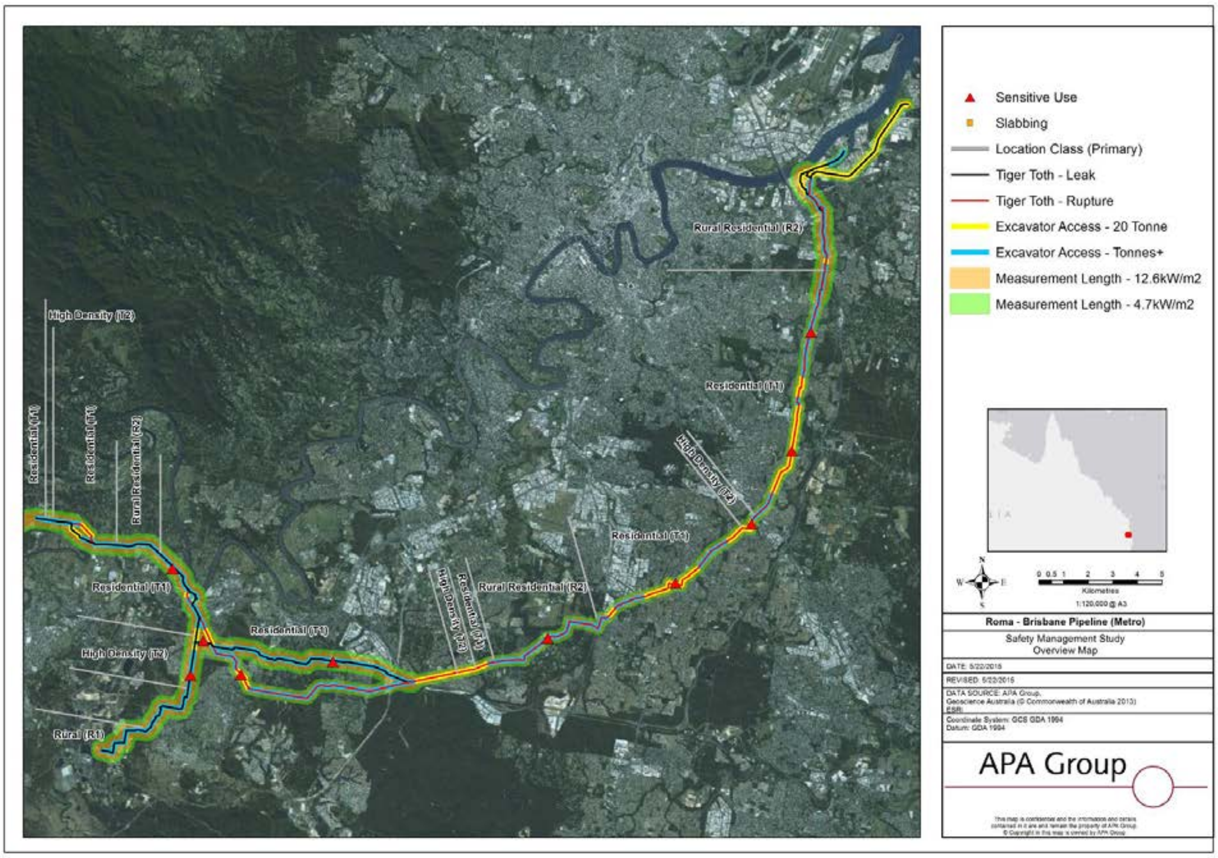
However, current forecasts do not support an economic case for the construction of metro looping phase 2 and 3 in timeframes consistent with the resolution of issues raised by urban encroachment and associated third party interference risks.

3.2 Urban encroachment

The original Roma to Brisbane Pipeline DN250, DN300 and DN200 pipelines were constructed in 1969. The DN400 looping pipeline up to Looping 6 was constructed between 1988 and 2002. At the time of construction, the pipeline traversed mostly rural areas, and was designed accordingly to the applicable standards of the time. Prior to 2007, design codes did not require retrospective consideration of high-consequence areas.

Since the time of construction, significant development has occurred particularly in the Brisbane outskirts, so that parts of the pipeline that were originally in rural areas are now surrounded by dense urban areas. To a lesser extent, growth in the towns along the pipeline such as Dalby and Toowoomba has also changed the land use within the measurement length. This means that in addition to the original 'Metro' DN300 and DN200 pipeline segments, significant portions of the DN250 and DN400 pipelines are now located in high-consequence built up areas.

As can be seen in the satellite image below, the metro section is located in dense, established suburbs of Ipswich and Brisbane, including Karalee, Riverview, Redbank, Collingwood Park, Camira, Forest Lake, Sunnybank, Eight Mile Plains, Wishart, Mansfield, Carindale, Carina, Tingalpa and Murarrie. A high proportion of the pipeline is located in road reserve, and therefore more exposed to other utility construction and maintenance threats, than in comparable pipelines in other major Australian cities.



Key pipeline details are provided in the following table, including the lengths of pipeline segments assessed to be located in High Consequence Areas (location class of T1, T2, S, I or HI for consequence escalation). The location class requirements are defined in AS 2885.1-2012, assessed through the SMS and Location Class review process and the ALARP study, and described further below.

Pipeline	DN200	DN250	DN300	DN400
Commissioning Date	1969	1969	1969	1988 - 2002
Length of pipeline	2 km	399 km	38 km	404 km
MAOP	4200 kPa	7136 kPa	4612 kPa Bellbird Park – Mt Gravatt 4200 kPa Mt Gravatt – SEA	9300 kPa Wallumbilla – Condamine 9600 kPa Condamine to Swanbank/ Ellengrove
Outside diameter	219.1 mm	273.1 mm	323.9 mm	406.4 mm
Wall thickness	4.78 mm	4.78 / 5.19 / 6.35 mm	5.19 mm	5.7* / 6.8 / 8.1 / 8.85 / 9.5 / 9.7mm
Pipe specification	API 5L X46	API 5L X46	API 5L X42	API 5L X60 / X70 / X80

12.6 kW/m2 radiation contour	102 m	166 m	159 m	288 m
4.7 kW/m2 radiation contour (Measurement Length)	167 m	272 m	261 m	472m
Length in High Consequence Areas	2.1 km	35.3 km	27.5 km	61.8 km

* Note that due to the staged construction of the DN400 pipeline over many years, several wall thickness and grade combinations exist.

It should also be noted that the Lytton Lateral and Metro Looping 1 pipelines are not in the scope of this Business Case, as they were designed and constructed in accordance with AS 2885.1-2007 or later with full cognisance of high-consequence area requirements.

3.3 Design standards and legislation

3.3.1 Petroleum & Gas (Production & Safety) Regulations 2004

APTPPL is licensed to operate the RBP under the Queensland *Petroleum & Gas (Production & Safety) Act and Regulations 2004.* Schedule 1 to the regulations sets AS2885 as a preferred standard under the Act. Under regulation 7 this means that pipeline construction and operation is mandated to comply with AS2885.

3.3.2 Australian Standard AS 2885

Hydrocarbon transmission pipelines such as the RBP have an Australian Standard for their design and construction, AS 2885.1. A key part of AS 2885 is the Safety Management Study (SMS) process, which requires Licencees to identify all credible threats to the safety of the pipeline, assess the risk level for threats that could cause failure, and apply appropriate mitigation measures. The likelihood and consequence descriptors, and the risk assessment matrix, are set out in Appendix F of AS 2885.1-2012 and must be used for all pipeline SMS risk assessments. Copies of these are provided in the Appendix to this Business Case for reference.

Under AS2885.1 each pipeline segment is assigned a location class of either: T1, T2, R1 or R2. This classification is based on the land use within the 'Measurement Length' (ML). The ML is the distance from the pipeline that a full bore rupture would affect the surrounding area causing serious injuries to people. The ML is dependent on operating pressure and diameter of the pipeline, thus each pipeline has a different ML.

This standard requires physical and procedural mitigation measures to be applied during design and operation. The number of physical and procedural measures required depends on the location classification and is mandatory for new pipelines. For existing pipelines, the standard requires that they are assessed against the requirements of Clauses 4.7.2 and 4.7.3, which set out the criteria for "no rupture" and maximum energy release rate in high consequence areas. Where existing pipelines do not comply with either clause, mitigation options must be assessed in accordance with Clause 4.7.4 and ALARP shall be achieved. This change was first introduced in the 2007 revision of AS 2885.1 and is clearly applicable to the RBP where it is located in the metropolitan area of a major capital city.

The specific HCA requirements are spelled out in section 4.7.2 of the Standard as follows:

- *In Residential (T1), High Density (T2), Industrial (I), and Sensitive (S) location classes and in Heavy Industrial (HI) location class (where pipeline failure would create potential for consequence escalation), the pipeline shall be designed such that rupture is not a credible failure mode.*

This requires assessment of the pipeline's critical defect length against the maximum credible puncture length from 3rd party interference threats.

Also, in regard to maximum energy release rates in the event of a pipeline failure, Section 4.7.3 states the following:

- *In high consequence locations where loss of containment can result in jet fires or vapour cloud fires …the maximum discharge rate shall not exceed 10 GJ/s in Residential and Industrial locations or 1 GJ/s in High Density and Sensitive locations.*

Energy release rates must be calculated for the various wall thickness / grade / MAOP / machinery threat combinations and compared to these limits.

Finally, the standard states for a Change in Location Class section 4.7.4: *"… safety assessment shall be undertaken and additional control measures implemented until it is demonstrated that the risk from a loss of containment involving rupture is ALARP." (As Low As Reasonably Practicable).* Clause 1.4 which describes retrospectivity clearly identifies this part of AS 2885.1 as requiring application to existing pipelines.

The intention of this part of the Standard is that all existing AS 2885 pipelines are to be assessed against these requirements. For such matters of significant public safety interest, 'grandfathering' of existing pipelines is not allowed under the Standard. Licencees are required to consider the risk levels and to demonstrate ALARP, and are required by the Standard to consider all options, including MAOP reduction, pipe replacement, pipeline relocation, modification of land use, and implementing additional physical and procedural protection.

3.4 APA's approach to High Consequence Area risks on the RBP

APA first considered the retrospective high-consequence area requirements in the 2010 RBP safety management study review (the first full SMS in the 5-yearly cycle since the 2007 release of AS 2885.1). It was shown in that SMS that the rupture risk in HCAs was no higher than Intermediate, and ALARP was demonstrated by a basic Maximum Justifiable Spend (MJS) analysis, which was considered the industry standard at that time. That analysis determined that capital costs for effective mitigation would greatly exceed the MJS. The SMS report flagged APA's intention to eventually construct a looping pipeline in the metro area and noted that an optimum risk outcome would be to decommission the existing metro pipeline when the looping pipeline became operational.

Since that time, the Australian and international pipeline industry has refined its approach to risk assessment and ALARP analysis. The APGA Research and Standards Committee (RSC) and the Energy Pipelines Cooperative Research Centre (EPCRC) have invested significantly in this area, particularly for high-consequence, low-likelihood risks such as pipeline failures. This topic has featured at prominent Australian and international industry and research conferences. ALARP guidelines have been developed to enable Licencees to better understand and demonstrate that all further risk reduction measures would incur costs grossly disproportionate to their incremental benefit. APA was a participant and supporter of this research.

The EPCRC final report – Project RP4.21A: Understanding ALARP and Interim Report One - Project 4.20A Third Party Risks to Pipelines were utilized in understanding the technical obligations imposed by ALARP. These reports are attached but are confidential to APGA RSC members.

Other EPCRC research is in progress and further reports and projects are likely to develop in the coming months and years.

During this period, notable incidents such as the 2008 Varanus Island (Western Australia) pipeline failure, and resultant gas supply crisis, and the 2010 San Bruno (California) pipeline rupture which caused eight deaths, occurred. These sharpened the industry's focus on such risks and modern societal expectations of safe pipelines. In parallel, APA carried out analysis on emerging risks which identified the RBP as one of APA's pipelines most exposed to risk of failure from 3rd party damage in populated areas.

APA carried out further SMS reviews of the RBP through 2014 (for the Metro section) and 2015 (for the remainder of the RBP), with an important focus on the HCA requirements of AS 2885.1. APA also carried out a thorough risk reduction options assessment and ALARP analysis as a specific action resulting from the SMS review. This was done to a substantially deeper level than previous analyses and considered all options specified in AS 2885.1 section 4.7.4 in some detail. This ALARP assessment continued through to 2016 and is the primary driver of the risk reduction works set out in this Business Case. The ALARP report is available (document 320-RP-AM-0078).

The outcomes of the SMS and ALARP analysis means that it is necessary to undertake additional work to protect the pipeline in order to bring the RBP in compliance with AS2885 by achieving ALARP for risks involving pipeline rupture in populated areas. This outcome is in line with the intention and philosophy of AS 2885 and will help address the risks associated with what is a significant example of an aged and vulnerable pipeline located in a populated area.

The ALARP options considered and recommendations made are summarized in later sections of this Business Case.

4 Risk Assessment

The risks associated with urban encroachment are varied. However, as required by AS2885.1 in the SMS process, APTPPL have assessed the risks associated with the four most common types of construction equipment that could pose a risk to the pipeline; a 20 ton excavator using a tiger teeth bucket, a 35 ton excavator using a tiger teeth bucket, a vertical auger and a horizontal drill, in the SMS process.

The worst consequence that could materialize is the inadequate pipeline protection leading to a full bore rupture, with ignition of the released gas and multiple fatalities including passers-by and members of the public. Thorough assessment of these risks is undertaken in the AS 2885 SMS process.

The specific risk assessment for driving this work was undertaken as part of the ALARP study. Refer to Section 7 and Appendix E of the ALARP study report for an overall summary of the ALARP options and resulting risk evaluation. A summary of the risk assessment outcomes for the most credible options is reproduced below.

Option	No Rupture compliant	Energy Release compliant	20t Excavator Risk	35t Excavator Risk	Vertical Auger Risk	HDD Risk	Comment
Current Status	No	No	Intermediate (Major/Remote)	Intermediate (Catastrophic/ Hypothetical)	Intermediate (Major/Remote)	Low (Major/ Hypothetical)	With existing controls
MOP Reduction to achieve >1.5 CDL factor or 30% SMYS (recommended where possible)	Yes	T1 only	Intermediate (Major/Remote)	Low (Major/ Hypothetical)	Intermediate (Major/Remote)	Low (Major/ Hypothetical)	Removes catastrophic rupture consequence; minor improvement on other threats
Pipe Replacement	Yes	T1 and T2	Negligible (Minor/Remote)	Negligible (Minor/ Hypothetical)	Low (Major/ Hypothetical)	Low (Major/ Hypothetical)	
Slab protection (recommended where MOP reduction not possible)	No	No	Low (Major/ Hypothetical)	Intermediate (Catastrophic/ Hypothetical)	Low (Major/ Hypothetical)	Low (Major/ Hypothetical)	Hypothetical threats become close to non-credible (2 orders of magnitude improvement within Hypothetical range)
Partial MOP reduction to achieve CDL factor between 1 and 1.5, plus slab exposed areas (recommended for some sections)	No	T1 only	Low (Major/ Hypothetical)	Low (Major/ Hypothetical	Low (Major/ Hypothetical)	Low (Major/ Hypothetical)	While not achieving No Rupture compliance, the most likely large excavator threat consequence becomes a leak only.

5 Options Considered

As part of the AS 2885.1 ALARP assessment, Clause 4.7.4 requires the assessment to consider specific alternatives, at least including MAOP reduction, pipe replacement, pipeline relocation, modification of land use, and implementing additional physical and procedural protection. This requirement has been addressed fully in the ALARP report and the realistic alternatives for the RBP have been summarised in the ALARP report and this Business Case.

In relation to MAOP/MOP reduction, permanent reduction of MAOP in pipeline segments along the RBP is not feasible due to the need for pigging for integrity management purposes. Intelligent pigging requires specific flow conditions to be successful and low pressures typically result in high velocities and degraded ILI performance.

However, APA has assessed that MOP reduction would achieve similar risk reduction outcomes. Reduced MOPs can be implemented and would be effective better than 99% of the time, as pressures would infrequently be raised above MOP for pigging or contingency operations (a few days per year). During these occasions, additional procedural measures can be implemented. For ALARP assessment purposes, APA considers that MOP reduction is equivalent in effectiveness to MAOP reduction.

In relation to land use changes, APA is not a Referral Authority at the planning level for all jurisdictions and thus has very limited rights to influence any land use changes within the measurement length but outside the pipeline easement. This has two major problems for APA, firstly APA is not always required to be notified of a land use change and second APA's ability to object to a land use change can be very minimal. Also, the existing land within the measurement length is highly developed already in many areas and it would not be practical to sterilize such quantities of land in urban areas.

For each segment of pipeline, APA has therefore considered the MOP reduction options to achieve no rupture and energy release rate compliance, possible sites for pressure regulating facilities, pipeline replacement options, and physical protection options. Details of these options are set out in the ALARP study report. The realistic options considered are set out in the following sections.

5.1 Option 1 – Do Nothing

This approach would undertake no additional capex. There would be no slabbing expenditure or expenditure to build the facilities necessary to reduce the pressure on any part of the RBP. The existing controls would be relied upon, which involve mainly procedural measures and the limited existing resistance of the pipe wall to mechanical damage with the potential of pipeline rupture.

5.1.1 Cost/Benefit Analysis

- The benefit of this approach is that no additional capex would be incurred.
- However, the pipeline would not be in compliance with AS2885 using current ALARP assessment. This would expose APTPPL to significant financial and reputational risk as well as expose the public to levels of safety risk that APTPPL and AS 2885 consider too high. This would be counter to the intentions of AS 2885.
- It may also place APTPPL in breach of the Petroleum & Gas (Production & Safety) Act.

5.2 Option 2 – Maximum Operating Pressure Reduction

This option involves MOP Reduction only, so that at the new MOP, pipeline segments meet code compliance for maximizing the critical defect length of the pipeline. Critical defect length depends on maximum pressure and to meet No Rupture requirements, is required to be at least 1.5 times the maximum damage length from credible threats in the area.

MOP reduction can be achieved by installing additional regulating stations upstream of the metropolitan area. Capacity modelling and options analysis has determined that it is feasible to implement pressure regulating stations on both the DN250 and DN400 pipelines at Brightview. Due to existing customers supplying into the DN250 pipeline at Wallumbilla, a cross-connection is also required to flow DN250 gas into the DN400 and onward to Brisbane. The pressure set points at inlets to the DN300 Metro at Bellbird Park and Ellengrove would be reduced.

Expected MOPs to achieve no rupture compliance for the pipelines are as follows:

- DN400: 6.3 MPa
- DN250: 3.3 MPa
- DN300: 3.0 MPa

This arrangement would impact supply and would mean that at these pressures, the RBP would be unable to meet the supply pressures required in the Metro area for major industrial and distribution network customers. Therefore, construction of a new compressor station in the Metro area, nominally at Carina or Murarrie, would be required.

Concept selection for this is an electric drive compressor station, with two units. Challenging design and construction is anticipated due to the limited locations available within the Brisbane metro area.

Other measures would still be required for areas where MOP reduction is not feasible, i.e. west of Brightview.

5.2.1 Cost/Benefit Analysis

The capital cost of this option is estimated as $31M, including $6M for three regulating skids at Brightview and $25M for a new compressor station at Carina or Murarrie. It is noted that this option still has some inherent risk to the public from third party interference, though with reduced consequence as a result of a leak and ignition rather than rupture and ignition. The No Rupture requirements of AS 2885.1 Clause 4.7 are met. It is also noted that a relatively small quantity of additional slab protection would still be required in T2 and Sensitive areas as the leak rates can still exceed 1 GJ/s.

Overall, this option would achieve a satisfactory level of risk, however the high costs and other new risks introduced by having a compressor station, with associated noise, gas vent/flare risks and general heavy industrial site in a suburban area mean it is less desirable than some other options.

5.3 Option 3 – Physical protection

Under this approach physical barriers in the form of slabbing or similar would be added to all areas of the RBP that are located in HCA location classes. This involves construction of a reinforced concrete slab buried or other penetration barrier shallowly in the ground above the pipeline, and extending approximately 600 mm either side of the pipeline, in areas that are accessible for potential excavator or auger strikes. No changes to MOP or MAOP would be made under this option.

This approach is common in the pipeline industry where new land use changes affect the location class and is often negotiated as part of the approval process for property developments near pipelines. In the case of the RBP, where suburban development has already occurred, mainly prior to the 2007 revision of AS 2885.1, retrofitting of slab protection would be carried out.

5.3.1 Cost/Benefit Analysis

For option comparison purposes, this work would be expected to cost $32.9m based on a unit rate of slabbing costs per km across all HCA along all diameters of the RBP downstream of Brightview, making it considerably more expensive than the preferred option. Given the costs of slab retrofitting, in most cases it is cheaper to implement MOP reductions.

Additional work would still be required west of Brightview, as with other options. The only feasible option for these areas, where MOP reduction is not possible, is physical slab protection. The HCAs west of Brightview are generally less densely populated than the Brisbane region and will be completed with the appropriate prioritization after the Brisbane Metro area works are completed.

In general the ALARP approach requires consideration of cost of the various options. Where slabbing costs are cheaper than MOP reduction, slab protection may be selected. However, for areas where MOP reduction is possible without restricting supply, this is considered to be a more effective risk reduction option than slabbing. If MOP reduction can be implemented, it should be as this directly reduces the consequences of a worst-case scenario. Slab protection is effective in reducing the likelihood of such an event only. In particular, large excavators if they avoid or remove the slab protection, can still cause a full-bore rupture with catastrophic consequences.

5.4 Option 4 – Combination MOP Reduction and Barrier Slabs

This option is a combination of Option 2 and Option 3, selected to be the most cost-effective while still achieving ALARP. The analysis in the ALARP study concluded that the best cost and risk outcome for 3rd party damage was to undertake MOP reduction (as per Option 2 above) where this could be done whilst still meeting operational capacity requirements without compression or looping construction, and to install physical protection (as per Option 3 above) where MOP reduction was not feasible.

This solution is to implement MOP reduction to either achieve full 'No Rupture' compliance where it is feasible to do so, or to achieve maximum reduction of risk possible (partial MOP reduction) – with no impact to customer supply requirements. While the partial MOP reduction does not achieve full compliance with the HCA requirements (1.5 factor times CDL – refer to ALARP report), the reduction improves the safety factor over the CDL to between 1.0 and 1.5, making the catastrophic rupture significantly less likely and reducing the consequence of a leak failure due to the lower pressure.

This MOP reduction is to be achieved by additional regulating stations at Brightview on the DN250 and DN400 (plus an interconnect between the two) as per Option 2. An additional MLV is required at Ellengrove on the DN300 pipeline to enable the upstream section to run at a lower MOP. A new regulating station is also required at Eight Mile Plains or Mt Gravatt to manage the downstream pressures. This location maximizes the length of pipeline covered by the MOP reduction in order to minimize the slab protection requirements. These regulating stations and MLVs will adequately achieve the following target pressures, which have no impact on customers:

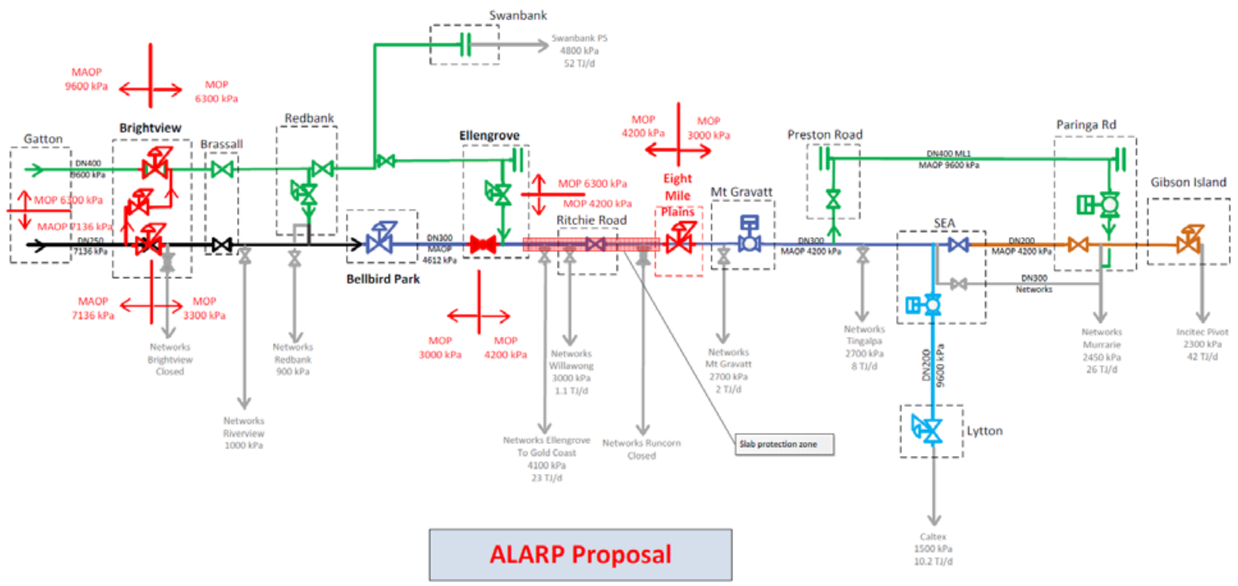
- MOP reduction in the DN250 pipeline from Brightview to Bellbird park to 3300 kPa;
- MOP reduction in the DN400 pipeline from Brightview to Swanbank and Ellengrove to 6355 kPa;
- MOP reduction in the DN300 Metro pipeline from Bellbird Park to Ellengrove to 3050 kPa
- MOP reduction in the DN300 Metro pipeline from Ellengrove to Eight Mile Plains to 4200 kPa
- MOP reduction in the DN300 Metro pipeline from Eight Mile Plains to SEA to 3050 kPa

Adjustment of existing MAOP specification breaks will be considered in the scope of this project where practicable to ensure code compliance is maintained.

In addition to the above achievable MOP reduction, physical protection barriers (pipeline concrete slab or equivalent) are required at the following locations:

- All HCA zones where excavator and auger access is credible, including road reserve, parkland and private properties other than suburban residential yards, throughout the Ellengrove to Eight Mile Plains section of the metro pipeline where MOP reduction cannot achieve No Rupture (only a partial MOP reduction is possible) – this includes 12.3 km of pipeline. Approximately 7.7 km of barrier protection is required.
- Outside of the Ellengrove to Eight Mile Plains section - In T2 and S location classes, if the energy release rate at the reduced MOP exceeds 1GJ/s – localised areas only around schools and similar;
- At identified hot-spot locations where the pipeline may be particularly exposed to external interference such as road crossings, changes of direction and branch connections within road reserve;

The proposed approach is shown in the below schematic sketch.



5.4.1 Cost/Benefit Analysis

The estimated cost of implementing this option is $10.970M over the next 6 years. This includes:

- FY16 FEED works - $0.120M;
- FY17 and FY18 detailed design and installation of additional regulating stations, MLV and 9.5km first priority protective barrier installation - $9.65M (refer cost breakdown in the forecast section); and
- a continued protective barrier installation program for medium priority high consequence areas for the 4 years after (0.3M / year):

It is considered that this option is the most cost-effective and efficient way to reduce risk associated with 3rd party interference damage in populated areas, achieve compliance with AS 2885 and legislative requirements, and still maintain supply requirements to customers without undertaking major capital works of pipeline looping or new compressor construction in the metropolitan areas.

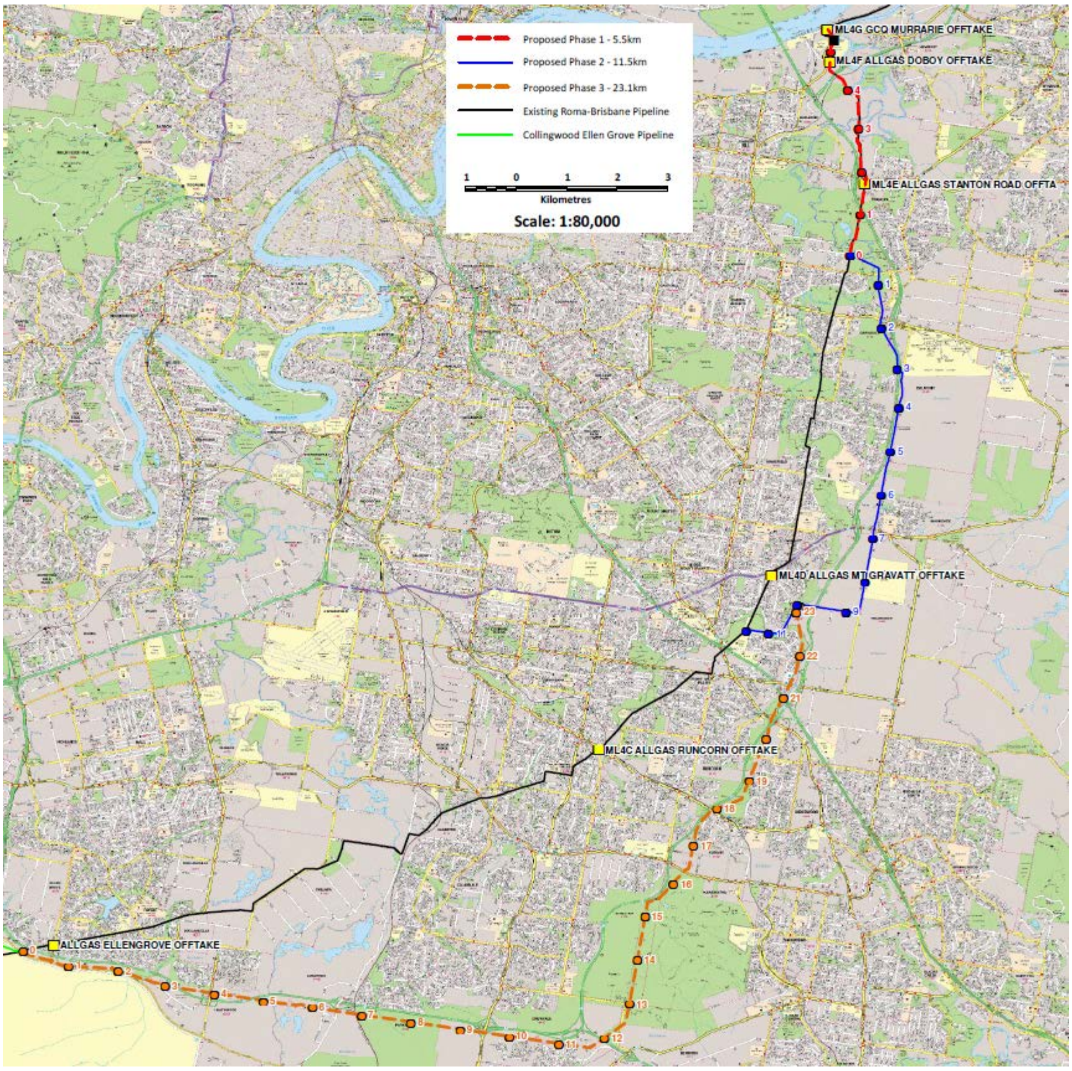
5.5 Option 5 – Metro Looping (Pipe Replacement)

One of the options for risk reduction is to replace all the non-compliant pipe in high consequence areas with new, modern no-rupture pipe. The most practical way to do this would be to construct a looping pipeline through the remaining non-looped areas of the Brisbane Metro pipeline, between Ellengrove and Preston Road (Carina), and to construct replacement DN250 sections where there is non-compliant pipe in high consequence areas.

Previous engineering studies for the continuation of the Metro Looping works had identified a potential route through the Brisbane area in line with other recent infrastructure installations and outside the existing pipeline easement. While a significant portion of the pipeline would still be in HCAs, the risks would be designed out by physical pipe protection using stronger and heavier-walled pipe, buried at an appropriate depth of cover. The project would involve 35 km of high grade steel, heavy-wall DN400 pipeline construction compliant with AS 2885.1 and some sections of DN250 pipeline.

This option would also involve pressure reduction of the existing DN300 pipeline to meet the AS 2885 requirements as per Option 2. Construction of new offtakes from the new loop may also be required, to service existing customer connections currently supplied from the DN300 or DN250 pipeline.

Other measures such as MOP reduction or slab protection would still be required for the DN250 and DN400 pipelines.



5.5.1 Cost/Benefit Analysis

The estimated minimum cost of the metro looping is $120-150M (for 35km Metro Loop plus Brightview pressure reduction facilities), based actual costs per kilometer of the Metro Looping 1 project. There would be additional costs that weren't evaluated as part of the previous metro looping works, incorporating new offtakes for existing customers off the original line to meet customer requirements and reduce pressure to full compliance on the original line.

This will be a new pipeline that will provide additional capacity. It is considered the best long-term solution for the Brisbane metro area both providing for future demand and mitigating the risks associated with the existing pipeline. It would also provide redundancy of supply in the event of a failure or shutdown of the existing single Metro pipeline. However, the reason that this project has been deferred is that there is currently insufficient demand for the capacity that it would provide in the Brisbane area and therefore there is currently no commercial driver for it to proceed.

Should demand for capacity in the Brisbane area increase in future, or if pipeline integrity concerns increase toward end of life, this option may be revisited.

5.6 Option 6 – Procedural protection

This option considered upgrades of procedural protection alone. Current procedural measures in high consequence areas include daily (7 days per week) pipeline road patrol; landowner and 3rd party liaison, community awareness and dial before you dig, pipeline marker signage, corridor agreements with road authorities, and planning notification zones in place with local councils.

APA considers that all effective procedural controls are already in place for the RBP, notwithstanding that improvements are always possible and are ongoing at the time of this business case. Possible additional procedural controls include:

- Increased patrol activity beyond once per day, e.g. two or three times per day, using additional resources
- Increased surveillance by other means such as CCTV, satellite imagery, drone or helicopter patrol
- Remote intrusion monitoring using fibre optic cables

These options are unlikely to provide any effective additional risk mitigation, since the issue at hand is already a low-likelihood but high-consequence pipeline failure. They may marginally reduce the likelihood but have no effect in the controls-fail scenario when 3rd party works are not detected. APA will continue to monitor these emerging technologies for satellite monitoring, drones and fibre optic intrusion detection.

5.6.1 Cost/Benefit Analysis

For the purpose of cost-benefit analysis, a scenario of four additional patrol resources has been considered, which would enable two or three patrols of each section per day, including a night patrol for roadworks and other night time activities.

It is anticipated that the cost of this additional pipeline patrol based on $80,000 employee costs and $30,000 equipment costs per annum which with an assumed wage growth of 1.5% real over 40 years is $7m in present value terms.

However, the net risk reduction is minimal, due to the high consequence and already low likelihood of a catastrophic pipeline failure in a populated area. This option is not considered to achieve ALARP if done in isolation without implementing MOP reduction or protective slab barriers. The intent of AS 2885 is that pipelines are provided with sufficient physical protection as well as procedural measures. The intent of APA's ALARP assessment is to reduce the impact of the high-consequence / low-likelihood events, by improving rupture resistance and physical protection. The existing procedural protection in terms of patrolling is already considered to be as effective as it can be.

5.7 Summary of Cost/Benefit Analysis

TABLE 4: SUMMARY OF COST/BENEFIT ANALYSIS

Option	Description	Benefits (Risk Reduction)	Costs
Option 1	Do Nothing	Not feasible as action must be taken to AS2885.1 as per the ALARP report; exposure to breach of the Act and potential fine; no change to current risk level.	Nil capital
Option 2	Full MOP reduction to code compliance pressure – requires regulating stations at Brightview plus compression in metro area to maintain supply to customers	Removes catastrophic rupture consequence for large excavators and minor improvement on other threats and achieves full compliance; reduces consequence of event by making rupture not credible. Satisfactory option for ALARP but undesirable and costly compression in metro area required.	$31M capital for pressure reduction facilities at Brightview, plus new compressor station at Carina or Murarrie
Option 3	Physical protection across entire HCA distance Brightview to Gibson Island; no MOP reduction	Cost significantly higher than the preferred option and rupture consequence not removed where possible to do so. Effectively reduces likelihood of event.	$33M capital cost for protective slabbing over 65 km of pipeline

Option 4	Combination of MOP reduction and physical protection (above two options); regulator stations at Brightview, MLV at Ellengrove, regulator at Eight Mile Plains; Slabbing only in non-MOP reduction zone; no compression.	Achieves optimum cost and risk solution; reduces MOP where feasible to do so and slab remaining HCAs. Avoids undesirable metro compression or high-cost looping. Preferred option according to ALARP study..	$10.97M
Option 5	Pipe replacement via Metro Loop project; 35 km of new pipeline in metro area; reduce pressure in existing Metro. Also requires Brightview modifications for DN250 and DN400 pipelines.	Commercial driver not currently present due to no demand for increased capacity; Best long-term risk reduction option but cost significantly higher than preferred option and difficult to justify on ALARP risk reduction basis alone.	$120-150M for 35km Metro Loop plus Brightview pressure reduction facilities
Option 6	Procedural Measures – increased patrolling	Significant increase in operations personnel for constant patrolling; does not comply with AS2885.1 requirement for physical protection measures in HCAs. Impractical option and still relies heavily on human interface.	$7 M over the access arrangement period

6 Proposed Solution

6.1 What is the Proposed Solution?

The proposed solution is to implement a combination of MOP reduction and physical protection as detailed in Option 4 above.

The intent of this option is to achieve full 'No Rupture' and energy release rate compliance where it is feasible to do so, or to achieve maximum reduction of risk possible (partial MOP reduction) – with no impact to customer offtakes. Where full compliance is not feasible, physical barrier construction will be implemented.

Substantial engineering consideration has been given to the development of this proposal through the SMS and ALARP process and the FEED works in FY16 looking at the proposed regulator stations.

6.2 Why are we proposing this solution?

This approach is the lowest cost solution assessed as meeting the ALARP requirements of AS2885.1. The Metro Looping solution (Option 5) or the MOP Reduction (Option 2) are the other two credible alternatives to achieve ALARP but both are significantly more expensive than Option 4.

Option 4 removes the catastrophic rupture consequence and achieves compliance levels similar to a new pipeline, in all locations where it is feasible to do so, by reducing MOP. Slab protection (which is typically more costly on a per km basis) is implemented where MOP reduction cannot achieve a satisfactory risk reduction.

Refer to the ALARP study report for further detail on this options analysis.

6.3 Consistency with the National Gas Rules

The capital expenditure is compliant with rule 79 of the National Gas Rules.

6.3.1 Rule 79(2)

The capex is necessary to maintain and improve the safety of services under r79(2)(c)(i) and is necessary to maintain the integrity of services under r79(2)(c)(ii) as the work is necessary to reduce the risk (frequency and consequence) of pipeline rupture to a level that is compliant with AS2885.

6.3.2 Rule 79(1)

Rule 79(1)(a) states:

> *the capital expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services*

This capital expenditure is consistent with rule 79 as it 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 personnel and is of a nature that a prudent service provider would incur.

Efficient – The option selected is the most cost effective long term option that meets the necessary operational requirements in order remain compliant with legislative and regulatory obligations and Australian standards. The work was identified and considered under APA's expenditure framework and will be undertaken in accordance with APA's procurement policies.

Consistent with accepted and good industry practice – Addressing the risks associated with pipeline rupture associated with urban encroachment around the pipeline is accepted as good industry practice. In addition the reduction of risk to as low as reasonably practicable in a manner that balances cost and risk is consistent with Australian Standard AS2885.

To achieve the lowest sustainable cost of delivering pipeline services – The sustainable delivery of services includes reducing risks to as low as reasonably practicable and maintaining reliability of supply.

6.4 Forecast Cost Breakdown

FEED works will be completed in July 2016 and the additional stations will be installed in FY17 and FY18, along with bulk of the physical protection barrier installation works. FY19 will continue an annual program for remaining medium priority high consequence area protective barrier installations into FY19, 20 and 21.

This project is broken in to three components for the purpose of cost estimation.

1. FEED works (including preliminary design drawings and detailed cost estimate): $120k
2. Regulating and MLV station installation:
    a. Brightview Regulating Station - DN250 and DN400, including interconnect: $1,530k
    b. Ellengrove MLV: $150k
    c. Eight-mile Plains Regulating Station: $820k
    d. Hot Taps – $1,350k
    e. Other direct cost items (incl detailed design) across all sites- $3,560k
3. Physical Barrier protection installation:
    a. FY17 / 18: 9.5km - $2,240k
    b. FY19 – 22: annual remaining cost $300k per year

The following table shows the detailed cost breakdown for the FY17 – FY18 Risk Mitigation works:

FY16 – Scoping and FEED	
FEED costs (Engineering and project management)	$120,000
FY17-18 Risk Mitigation Works – Regulating Stations & Protective Barriers – Budget Estimate	
Project Management	$890,000
Land & Approvals	$70,000
Design	$1,550,000
Procurement	$2,570,000

Construction	$4,320,000
Commissioning & Handover	$250,000
FY17-FY18 TOTAL	$9,650,000
FY19-22 Risk Mitigation Works – Continuation of Protective Barriers	
4 years @ $300,000 p.a.	$1,200,000
TOTAL PROGRAM ESTIMATE	$10,970,000

The cost estimate for the FY17-18 works have been developed based on FEED works undertaken in FY16 and a detailed cost breakdown including material procurement items and project CTR record and schedule for completion.

Appendix A – AS 2885 Risk Assessment Process

AS2885 requires that where excavation equipment in the location has the potential to rupture the pipeline, and that environment is or will become a high consequence area (T1, T2, I/HI or S), pipelines must meet specified requirements for no rupture and maximum energy release rate. If existing pipelines do not meet these requirements, risk reduction options must be considered including MAOP reduction, pipeline replacement or relocation, land use modification, or additional physical or procedural measures. ALARP is required to be achieved considering all of these options.

RBP SMS risk assessments were undertaken in compliance with AS2885.1. In schedule F AS2885.1 set out the basis for risk assessment this includes the definitions of severity of events

TABLE F2

SEVERITY CLASSES

	Severity class				
	Catastrophic	**Major**	**Severe**	**Minor**	**Trivial**
Dimension	**Measures of severity**				
People	Multiple fatalities result	Few fatalities; several people with life-threatening injuries	Injury or illness requiring hospital treatment	Injuries requiring first aid treatment	Minimal impact on health and safety
Supply	Long-term interruption of supply	Prolonged interruption; long-term restriction of supply	Short-term interruption; prolonged restriction of supply	Short-term interruption; restriction of supply but shortfall met from other sources	No impact; no restriction of pipeline supply
Environment (see Note)	Effects widespread; viability of ecosystems or species affected; permanent major changes	Major off-site impact; long-term severe effects; rectification difficult	Localized (<1 ha) and short-term (<2 y) effects, easily rectified	Effect very localized (<0.1 ha) and very short-term (weeks), minimal rectification	No effect; minor on-site effects rectified rapidly with negligible residual effect

NOTE: Significant environmental consequences may occur in locations that are relatively small and isolated.

It also sets out the definitions that apply to the frequency classes. Frequency classes are the likelihood of an event occurring.

TABLE F3

FREQUENCY CLASSES

Frequency class	Frequency description
Frequent	Expected to occur once per year or more
Occasional	May occur occasionally in the life of the pipeline
Unlikely	Unlikely to occur within the life of the pipeline, but possible
Remote	Not anticipated for this pipeline at this location
Hypothetical	Theoretically possible but has never occurred on a similar pipeline

Once these two things have been determined AS2885.1 prescribes the level of risk associated with that severity and frequency

TABLE F4
RISK MATRIX

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

Once a level of risk has been determined AS2885.1 then prescribes a risk treatment action.

TABLE F5
RISK TREATMENT ACTIONS

Risk rank	Required action
Extreme	Modify the threat, the frequency or the consequences so that the risk rank is reduced to 'intermediate' or lower For an in-service pipeline the risk shall be reduced immediately
High	Modify the threat, the frequency or the consequences so that the risk rank is reduced to Intermediate or lower For an in-service pipeline the risk shall be reduced as soon as possible, typically within a timescale of not more than a few weeks
Intermediate	Repeat threat identification and risk evaluation processes to verify and, where possible, quantify the risk estimation; determine the accuracy and uncertainty of the estimation. Where the risk rank is confirmed to be 'intermediate', if possible modify the threat, the frequency or the consequence to reduce the risk rank to 'low' or 'negligible' Where the risk rank cannot be reduced to 'low' or 'negligible', action shall be taken to— (a) remove threats, reduce frequencies and/or reduce severity of consequences to the extent practicable; and (b) demonstrate ALARP For an in-service pipeline, the reduction to 'low' or 'negligible' or demonstration of ALARP shall be completed as soon as possible; typically within a timescale of not more than a few months
Low	Determine the management plan for the threat to prevent occurrence and to monitor changes that could affect the classification
Negligible	Review at the next review interval

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Report

Roma Brisbane Pipeline

High Consequence Area ALARP Study

Owner		East Coast Grid Engineering QLD		Next Review Date	N/A
Document No		320-RP-AM-0078			
Rev	Date	Status	Originated	Checked	Approved
0	20 May 2016	Issued for Use	F Carroll Engineering Services Manager QLD	C Bonar Manager East Coast Grid Engineering	M Fothergill General Manager Infrastructure Strategy & Engineering

APA Group

EXECUTIVE SUMMARY

This report documents the ALARP assessment for the Roma Brisbane Pipeline (RBP) in relation to external interference threats in high consequence areas (HCAs). The scope of this study is all HCAs in the RBP where the pipeline was constructed prior to the HCA requirements first introduced in the 2007 version of AS 2885.1.

External interference threats considered in this study include excavators both 'typical' in built up areas of up to 20 tonne operating weight, and 'maximum' up to 35 tonne, as well as vertical augers and HDDs. Many RBP HCA pipe segments do not comply with the current AS2885.1 requirements for new HCA pipelines for no rupture and energy release rate. This study therefore considered all risk reduction options as required by Clause 4.7.4 of AS 2885.1-2012, with the following outcomes:

- Reduction of maximum operating pressure (MOP) is possible in many of the HCA segments whilst maintaining supply. Where implemented, in certain sections, this would remove the catastrophic rupture threat and achieve no rupture and energy release rate compliance. This is recommended for implementation and will require construction of new pressure regulation and mainline valve facilities.
- Increased physical barrier protection by slabbing is feasible. This greatly reduces the likelihood of external interference damage reaching the pipeline, even though the pipe wall may still not comply with no rupture and energy release requirements. This is recommended for implementation where MOP reductions cannot achieve sufficient risk reduction and at 'hot spots' of high-density or sensitive land use or exposed locations such as road crossings.
- Pipe replacement or relocation is possible but likely costs are disproportionate to the incremental risk reduction benefit, considering the significant lengths and built up locations of affected pipeline, when compared to the MOP reduction and slabbing options. Pipe replacement or relocation is not recommended, until such time as there is a commercial demand for increased capacity.
- Land use modification is not feasible in built up areas such as the RBP metropolitan HCAs. This option is not recommended due to the large quantities of land that would need to be sterilised within the measurement length.

ALARP has been reached by reducing MOP to as low as possible whilst maintaining supply. Where RBP HCA segments still do not comply with the AS2885.1 requirements for new HCA pipelines for no rupture and energy release rate for the largest normally expected excavator sizes, slab protection shall be installed. Slab protection of T2 and S areas will also be installed where energy release rate limits cannot be met.

The ALARP study has considered all available options to reduce the risk levels and determined that the above recommendations should be implemented in conjunction with minor improvements to the procedural measures such as 3rd party liaison and ROW patrols.

The approach taken in reaching ALARP has some conservatism (safety margin) built in. A bucket force multiplier of 1.3 has been used in determining penetration resistance. In addition, the protection from pipeline rupture was determined based on the critical defect length being not less than 150 percent of the axial length of the largest excavator defect. In the section between Ellengrove and Eight Mile Plains, the maximum defect length caused by a single tooth of a 20 T and a 35T excavator is less than the critical crack length but does not achieve the 150% factor. Additional protection through slabbing will be provided to reach ALARP.

The recommended approach for risk reduction involves:

- Reduction in MOP in the DN250 pipeline from Brightview to Bellbird Park to 3300 kPa.
- Reduction in MOP in the DN400 pipeline from Brightview to Swanbank and Ellengrove to 6300 kPa.

- Reduction in MOP in the DN300 Metro pipeline from Bellbird Park to Ellengrove to 3000 kPa, from Ellengrove to Eight Mile Plains to 4200 kPa, and from Eight Mile Plains to SEA to 3000 kPa. Pursue a further reduction in the Ellengrove section to 3900 kPa in conjunction with APA Networks.
- Installation of slab protection to other HCA pipe that is exposed to excavator/auger threats on a priority basis, commencing with the DN300 Metro area between Ellengrove and Eight Mile Plains.

The construction works required to implement the above include:

- 3 x pressure reduction / spec break skids to be installed at existing Brightview MLV station (DN250 PRS, DN400 PRS, Cross-connect PRS/Spec Break)
- 1 x new DN300 MLV at Ellengrove
- 1 x new pressure reduction station and MLV at Eight Mile Plains
- Minor changes to Redbank, Bellbird Park and associated facilities
- Slab construction in identified areas.

The high-level cost associated with the PRS and MLV station construction is $9 million. The high-level cost of the top priority slabbing protection (DN300 Metro Ellengrove to Eight Mile Plains) is $6.2 million. Further slab protection is likely to be an ongoing programme of work in future years.

Pipe replacement, including the previously proposed Metro Looping 2 and 3 projects, is not recommended as the costs are disproportionate to the further risk reduction achieved in comparison to the proposed approach of MOP reductions and slabbing.

In conclusion, this study has assessed all feasible risk reduction options for the RBP HCAs and the recommended combination of MOP reductions and physical barrier protection is considered to reduce the external interference risks to ALARP in accordance with AS 2885.1.

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APPENDICES

1 INTRODUCTION

1.1 Background

The Roma Brisbane Pipeline (RBP) is Queensland's first gas transmission pipeline, commissioned in 1969, under Queensland pipeline licence #2. It was constructed to supply natural gas from the Roma production fields to Brisbane for industrial, commercial and domestic use. It is owned and operated by APA Group.

The RBP is approximately 440 km in length between Wallumbilla and Gibson Island. Main pipelines within the RBP system include:

- DN250 Wallumbilla to Bellbird Park – 1969 ("RBP Mainline")
- DN300 Bellbird Park to SEA – 1969 ("RBP Metro")
- DN200 SEA to Gibson Island – 1969 ("RBP Gibson Island")
- DN400 Wallumbilla to Moggill Ferry – 1988 to 2002 ("RBP Looping")
- DN400 Moggill Ferry to Swanbank – 2002 ("Swanbank Lateral")
- DN400 Collingwood to Ellengrove – 2002
- DN200 SEA to Lytton – 2010 ("Lytton Lateral)
- DN400 Preston Road to Paringa Road – 2012 ("Metro Looping 1")

Since the construction of the pipeline in the late 1960s, Brisbane and the surrounding southeast Queensland area has been subject to extensive urban development. Much of the eastern end of the pipeline, which would have skirted around the edge of the populated Brisbane area in the 1960s, is now heavily encroached by urban development and runs through dense suburban areas. A high proportion of the pipeline is located in road reserve, and therefore more exposed to other utility construction and maintenance threats, than in comparable pipelines in other major Australian cities.

The RBP system is the sole supply of natural gas to distribution networks in the southeast Queensland region, including Brisbane, Ipswich, the Gold Coast and surrounding regions. This is unlike most other Australian capital cities which are supplied by more than one pipeline system.

The RBP is identified as an emerging risk for APA Group due to the age of the pipeline, its limited resistance to external interference, and its location in populated areas in some parts of the pipeline. SMS reviews in 2014 and 2015 identified that parts of the pipeline do not comply with AS 2885.1-2012 requirements for "no rupture" in high consequence areas. The original pipeline system was designed to the prevailing US code (ASME B31.8-1967) and other codes prior to the introduction of high consequence area special requirements in the 2007 version of AS 2885.1.

1.2 Purpose of Report

The purpose of this report is to document the ALARP assessment of various threats to the RBP assets and their mitigation measures, including:

- AS 2885.1 Section 4.7.4 requirements for land use change to high consequence areas (HCAs), including no rupture compliance and energy release rate limits;
- Other external interference threats assessed as Intermediate and requiring ALARP to be demonstrated.

In accordance with AS 2885.1 section 4.7.4, a formal study is required to demonstrate that the risk levels are as low as reasonably practicable (ALARP). This report forms the ALARP study for the RBP and documents the risks and mitigation options for Licencee approval.

1.3 Scope

1.3.1 Pipeline Segments

The scope of this report includes all HCAs of the RBP system, including the following pipelines:

- The DN250 pipeline between Wallumbilla and Bellbird Park
- The entire DN300 Metro pipeline between Bellbird Park and the SEA scraper station
- The entire DN200 Gibson Island pipeline between SEA and Gibson Island
- The DN400 looping pipeline (stages 1-5) between Wallumbilla and Moggill Ferry
- The DN400 Swanbank Lateral from Moggill Ferry to Swanbank power station.
- The DN400 Collingwood to Ellengrove lateral (looping 6).

Note that the Lytton Lateral and Metro Looping 1 pipelines are excluded from this study as both were designed and constructed in compliance with the 2007 version of AS 2885.1, and therefore do not require additional ALARP analysis.

- Metro Looping 1 comprises approximately 5.8 km of DN400 API 5L X70 PSL2 pipe, 12.7 mm nominal wall thickness with a CDL of over 300 mm. The entire pipeline was designed for T1 and I location classes including HCA requirements and there has been no T2 or S development within its measurement length since construction in 2012.
- Lytton Lateral comprises approximately 5.4 km of DN200 API 5L X52 PSL2 pipe, 8.2 mm wall thickness, CDL of 178 mm. The entire pipeline was designed for T1 and I location classes and its original SMS confirmed that HCA requirements were met. There has been no T2 or S development within its measurement length since construction in 2010.
- Further to the above, both of these pipelines are designed to a MAOP of 9.6 MPa, however they are both supplied solely from the RBP Metro DN300 pipeline, which has an MAOP of 4.2 MPa. This means that until such time as a source of higher pressure is provided, such as further Metro Looping, actual operating pressures cannot exceed 4.2 MPa. Actual hoop stresses will be less than half of the design values and the actual CDL will be correspondingly higher.

1.3.2 Relevant Threats

The typical threats considered in this study reflect those identified in the SMS reviews as follows:

- The most common threat is an excavator up to 20 tonnes operating weight, engaged in maintenance or construction of other utilities, and
- The maximum credible threat is an excavator up to 35 tonnes operating weight, engaged in major roadworks or development activity.
- Vertical auger threats exist which typically bore beyond pipeline depth to construct or replace power poles or street lights or signs.
- Horizontal directional drilling as is commonly used for electricity or telecommunication cable construction.

In relation to excavator threats, the SMS considered that the larger excavators, e.g. 35 tonne and up, are not credible in areas where access is restricted, such as small suburban streets and private residential properties. It was further noted that these larger excavators are not a credible threat to be working in an uncontrolled manner in areas where overhead power lines exist in close proximity to the pipelines.

1.4 Calculation Methods and Assumptions

This study has adopted the principles and calculation methods of AS 2885.1-2012. Key calculations used in the study include:

- Critical defect length
- Radiation contours
- Excavator penetration resistance
- Energy release rate

Assessment criteria and inputs are detailed within each relevant section of this report. Key overall underlying assumptions for this study are as follows:

- The assessment of no rupture compliance has considered a 1.5 ratio of critical defect length to maximum excavator defect length. As per the intention of AS 2885.1-2012 Appendix M, the maximum excavator defect length has been selected as the maximum tooth length and this does not distinguish between tooth types.
- A B-factor of 1.3 has been used in the assessment of penetration and rupture resistance. This is aligned with the guidance in AS 2885.1-2012 Appendix M which suggests B=1.3 should be applied for high consequence areas.

2 DESCRIPTION OF PIPELINE SYSTEM

2.1 Pipeline Construction Details

The construction details of all subject RBP pipelines are listed in Table 1 below.

Table 1 Summary of RBP construction details

Pipeline	DN200	DN250	DN300	DN400
Commissioning Date	1969	1969	1969	1988 - 2002
Length of pipeline	2 km	399 km	38 km	
MAOP	4200 kPa	7136 kPa	4612 kPa Bellbird Park – Mt Gravatt 4200 kPa Mt Gravatt – SEA	9300 kPa Wallumbilla – Condamine 9600 kPa Condamine to Swanbank/ Ellengrove
Outside diameter	219.1 mm	273.1 mm	323.9 mm	406.4 mm
Wall thickness	4.78 mm	4.78 / 5.19 / 6.35 mm	5.19 mm	5.7* / 6.8 / 8.1 / 8.85 / 9.5 / 9.7mm
Pipe specification	API 5L X46	API 5L X46	API 5L X42	API 5L X60 / X70 / X80
12.6 kW/m2 radiation contour	102 m	166 m	159 m	288 m
4.7 kW/m2 radiation contour (Measurement Length)	167 m	272 m	261 m	472m
Length in High Consequence Areas	2.1 km	35.3 km	27.5 km	61.8 km

* Note that due to the staged construction of the DN400 pipeline over many years, a large number of wall thickness and grade combinations exist.

2.2 Typical Crossing Details

Major road and railway crossings were typically constructed as cased crossings, for example with a 14” or 16” diameter casing enveloping the 10” or 12” pipeline.

Depth of cover was typically specified on original RBP alignment sheets as 30” or approximately 750 mm. Increased cover was specified on a case by case basis, particularly in the Brisbane metropolitan area. Some roads in Brisbane required 8’ to 10’ of cover (2.4 to 3.0 metres).

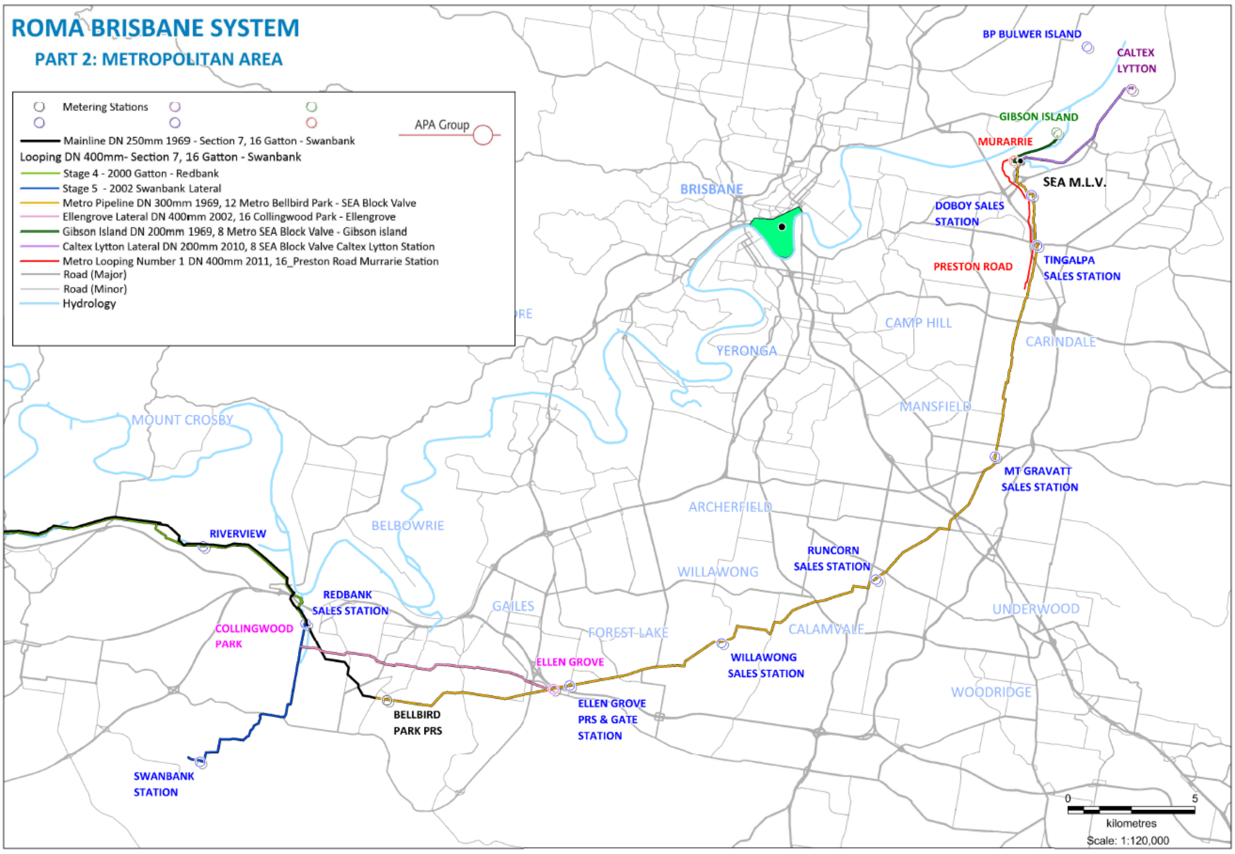
Many foreign service crossings also exist, which have typically been installed after the RBP.

Details are available on the pipeline alignment sheets and accompanying detail drawings.

2.3 Pipeline Route and Location Classes

An overview of the pipeline route of the eastern section of the RBP is shown in Figure 1 below.

Figure 1 Location Map



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In the metropolitan area of greater Brisbane, a significant proportion of the RBP is located in road reserves which are also used by other utilities.

3 AS 2885.1 HIGH CONSEQUENCE AREA REQUIREMENTS

3.1 General

Section 4.7 of AS 2885.1-2012 requires pipelines in high consequence (populated) areas to meet additional targets to maximise safety of the surrounding population for new pipelines. These include requirements to be assessed against a “no rupture” criterion and a maximum energy release rate in the event of pipe wall penetration. It is mandatory for new pipelines to comply with these requirements by selection of appropriate wall thickness and steel grade. Where existing pipelines do not comply with either Clause, mitigation shall be applied in accordance with Clause 4.7.4 regardless of whether or not there has been a land use change.

This study applies the “change of location class” approach (Clause 4.7.4) for retrospective application to the RBP high consequence areas. The specific AS 2885 requirements and the current status of the RBP pipeline segments are set out in the following sections.

3.2 No Rupture

3.2.1 Code Requirements

AS 2885.1-2012 Clause 4.7.2 states:

In Residential (T1), High Density (T2), Industrial (I), and Sensitive (S) location classes and in Heavy Industrial (HI) location class (where pipeline failure would create potential for consequence escalation), the pipeline shall be designed such that rupture is not a credible failure mode. For the purpose of this Standard, this shall be achieved by either one of the following:

(a) The hoop stress shall not exceed 30% of SMYS.

(b) The largest equivalent defect length produced by the threats identified in that location shall be determined. The hoop stress at MAOP shall be selected such that the critical defect length is not less than 150% of the axial length of the largest equivalent defect. The analysis shall consider through wall and part through wall defects.

3.2.2 RBP Compliance

Table 2 and Table 3 summarise the current RBP compliance with AS 2885.1 No Rupture provisions. Further details are available in the Fracture Control Plan documents for each pipeline. Supporting calculations for this report are attached in Appendix C.

In the Tables, note that the various pipe types have been listed in order of wall thickness. Due to grade variations, some thinner wall pipes are more resistant to external attack than other thicker pipes. For example, the DN400 X80 8.85 mm pipe has a CDL of 206 mm whereas the X60 9.5 mm pipe has a CDL of 170 mm.

Table 2 Summary of RBP compliance with No Rupture provisions – 1969 pipelines

Pipeline	DN250 4.78mm	DN250 5.16mm	DN250 6.35mm	DN300 4612kPa	DN300 4200kPa	DN200
Wall thickness (mm)	4.78	5.16	6.35	5.16	5.16	4.78
Steel Grade (API 5L)	X46	X46	X46	X42	X42	X42
MAOP (kPa)	7136	7136	7136	4612	4200	4200
Hoop Stress Compliance	DN250 4.78mm	DN250 5.16mm	DN250 6.35mm	DN300 4612kPa	DN300 4200kPa	DN200
Design hoop stress at MAOP (%SMYS)	63.7%	59.0%	48.0%	49.9%	45.5%	33.2%
Meets clause 4.7.2 (a) – hoop stress < 30% SMYS	No	No	No	No	No	No

Critical Defect Compliance – 20t	DN250 4.78mm	DN250 5.16mm	DN250 6.35mm	DN300 4612kPa	DN300 4200kPa	DN200
Critical defect length (mm)	73	84	116	118	132	145
Maximum defect length – 20t	95	95	95	95	95	95
CDL to Tooth Length ratio – 20t	0.77	0.88	1.22	1.24	1.39	1.52
Complies clause 4.7.2 (b) – 20t	No	No	No	No	No	Yes
Critical Defect Compliance – 35t	DN250 4.78mm	DN250 5.16mm	DN250 6.35mm	DN300 4612kPa	DN300 4200kPa	DN200
Maximum defect length – 35t	125	125	125	125	125	125
CDL to Tooth Length ratio – 35t	0.58	0.67	0.93	0.94	1.06	1.16
Complies clause 4.7.2 (b) – 35t	No	No	No	No	No	No

Table 3 Summary of RBP compliance with No Rupture provisions – DN400 pipelines

Pipeline	DN400 5.7mm	DN400 6.8mm	DN400 8.1mm	DN400 8.85mm	DN400 9.5mm	DN400 9.7mm
Wall thickness (mm)	5.7	6.8	8.1	8.85	9.5	9.7
Steel Grade (API 5L)	X70	X70	X70	X80	X60	X70
MAOP (kPa)	9600	9600	9600	9600	9600	9600
Hoop Stress Compliance	DN400 5.7mm	DN400 6.8mm	DN400 8.1mm	DN400 8.85mm	DN400 9.5mm	DN400 9.7mm
Design hoop stress at MAOP (%SMYS)	70.9%	59.4%	49.9%	39.9%	49.6%	48.6%
Meets clause 4.7.2 (a)	No	No	No	No	No	No

Critical Defect Compliance – 20t	DN400 5.7mm	DN400 6.8mm	DN400 8.1mm	DN400 8.85mm	DN400 9.5mm	DN400 9.7mm
Critical defect length (mm)	77	110	152	206	170	208
Maximum defect length – 20t	95	95	95	95	95	95
CDL to Tooth Length ratio – 20t	0.81	1.16	1.60	2.17	1.79	2.19
Complies clause 4.7.2 (b) – 20t	No	No	Yes	Yes	Yes	Yes
Critical Defect Compliance – 35t	DN400 5.7mm	DN400 6.8mm	DN400 8.1mm	DN400 8.85mm	DN400 9.5mm	DN400 9.7mm
Maximum defect length – 35t	125	125	125	125	125	125
CDL to Tooth Length ratio – 35t	0.62	0.88	1.22	1.65	1.36	1.66
Complies clause 4.7.2 (b) – 35t	No	No	No	Yes	No	Yes

3.3 Energy Release Rate

3.3.1 Code Requirements

AS 2885.1-2012 Clause 4.7.3 states:

> *In all locations, consideration shall be given to providing means of limiting the maximum discharge rate through a pipeline segment in the event of a loss of containment in that segment resulting from the design threat used in Clause 4.7.2.*
>
> *In high consequence locations where loss of containment can result in jet fires or vapour cloud fires the maximum discharge rate shall be determined and shall be approved. For pipelines carrying flammable gases, HVPLs and other liquids with a flash point less than 20°C, the maximum discharge rate shall not exceed 10 GJ.s-1 in Residential and Industrial locations or 1 GJ.s-1 in High Density and Sensitive locations. The energy release rate shall be calculated for quasi-steady state conditions that exist 30 seconds after the pipeline puncture.*

3.3.2 RBP Compliance

Table 4 below summarises the calculated energy release rates for the credible excavator threats, assuming tiger tooth bucket and B factor = 1.3 as recommended for high-consequence areas.

Table 4 Energy Release Rates for RBP Pipelines – B=1.3, Tiger teeth, Current MAOP

Pipeline	Wall thickness (mm)	Grade (API 5L)	MAOP (kPa)	20t Excavator (GJ/s)	35t Excavator (GJ/s)
DN250	4.78	X46	7136	30.3	30.3
	5.16	X46	7136	30.3	30.3
	6.35	X46	7136	0.3	30.3
DN300	5.16	X42	4612	1.7	27.5
	5.16	X42	4200	1.5	2.89
DN400	5.7	X70	9600	90.2	90.2
	6.4	X60	9600	90.2	90.2
	6.8	X70	9600	0.3	90.2
	7.7	X60	9600	0.3	90.2
	8.1	X70	9600	0.3	0.5
	8.85	X80	9600	0.3	0.5
	9.5	X60	9600	0.3	0.5
	9.7	X70	9600	0.3	0.5

Legend:

Red cells (>10 GJ/s): Not compliant for HCAs
Blue cells (1-10 GJ/s): Compliant for T1 and I HCAs
Green cells (< 1 GJ/s): Compliant for all HCAs incl T2 and S

3.4 Summary of RBP HCA Compliance

Table 5 is a summary of the HCA lengths on each RBP segment, indicating both the total length of HCA pipe and the length that is non-compliant with modern HCA No Rupture or Energy Release limits.

Table 5 Summary of RBP HCA Compliance

Pipeline Segment	Total HCA Length (km)	Non-Compliant HCA Length (km)
RBP DN250 Wallumbilla-Gatton	15.6	15.6
RBP DN250 Gatton-Bellbird	19.7	19.7
RBP DN300 Bellbird to Ellengrove	4.5	4.4
RBP DN300 Ellengrove to Mt Gravatt	12.8	12.3
RBP DN300 Mt Gravatt to SEA	10.2	9.8
RBP DN200 Gibson Is	2.1	2.1
RBP DN400 Wallumbilla to Gatton	23.1	23.1
RBP DN400 Gatton to Moggill	18.7	8.8
RBP DN400 Swanbank Lateral	10.7	8.3
RBP DN400 Collingwood Ellengrove	9.3	0.0
Grand Total	126.7	104.1

3.5 Change of Location Class – Code Requirements

AS 2885.1-2012 Clause 4.7.4 states:

Where there are changes in land use planning (or land use) along the route of existing pipelines to permit Residential, High Density, Industrial, or Sensitive development or Heavy Industrial development in areas where these uses were previously prohibited, a safety assessment shall be undertaken and additional control measures implemented until it is demonstrated that the risk from a loss of containment involving rupture is ALARP.

A location class change to Heavy Industrial requires compliance with this Clause only when pipeline failure in this location would create potential for consequence escalation.

This assessment shall include analysis of at least the alternatives of the following:

(a) MAOP reduction (to a level where rupture is non-credible).

(b) Pipe replacement (with no rupture pipe).

(c) Pipeline relocation (to a location where the consequence is eliminated).

(d) Modification of land use (to separate the people from the pipeline).

(e) Implementing physical and procedural protection measures that are effective in controlling threats capable of causing rupture of the pipeline.

For the selected solution, the assessment shall demonstrate that the cost of the risk reduction measures provided by alternative solutions is grossly disproportionate to the benefit gained from the reduced risk that could result from implementing any of the alternatives.

As mandated by Clause 1.4 of AS 2885.1, this assessment has been applied for all HCAs on the RBP system.

3.6 Risk Reduction Options

The following sections of this report describe the various options for risk reduction to achieve ALARP in accordance with Clause 4.7.4.

4 MAOP/MOP REDUCTION

4.1 General

Reduction of MAOP is possible for sections of the RBP. A number of possibilities exist to reduce the MAOP of the non-compliant pipelines (not complying with AS 2885.1 Clause 4.7.2 and 4.7.3) in HCAs. In general, pressure reduction is possible in the area east of Gatton, which coincides with the majority of the HCAs.

Due to operational requirements, pressure restrictions will need to be implemented as MOP rather than MAOP reductions. Under certain scenarios such as during pigging operations or emergency/contingency supplies, pressures may need to be raised above the reduced MOP. Under the above condition, the declared pipeline MAOP, and other resultant matters such as pipeline integrity defect assessment would have to consider the pipeline at full MAOP.

It is acknowledged that introducing MOP rather than MAOP restrictions may not achieve full compliance with the HCA requirements of clause 4.7.4 as required for new pipelines. However, APA considers for the RBP that an MOP restriction would achieve a similar risk reduction, since the actual pressure in the pipeline segments would be below the reduced MOP for 99% of the time or better. This is detailed in the ALARP assessment. The terminology used throughout this section of the report is MAOP however this should be read as inclusive of MOP restriction.

4.2 Target MAOPs

4.2.1 No Rupture Compliance

The target MAOPs for each pipeline are tabulated below. To achieve “no rupture” either requires maximum hoop stress to be below 30% of SMYS, or the CDL to exceed 150% of the maximum credible defect length.

For this reason the MAOPs to achieve no rupture compliance for the tooth length of both 20 tonne (the most common threat) and 35 tonne (the maximum credible threat in the metro area) excavators have been calculated, as well as the MAOPs to reduce hoop stress to 30% of SMYS. The target MAOPs for the 1969 pipelines are listed in Table 6 and for the DN400 pipelines in Table 7.

CDL calculations at various MOPs are attached at Appendix D.

Table 6 Summary of Target MAOPs – 1969 Pipelines

Pipeline	DN250 4.78mm	DN250 5.16mm	DN250 6.35mm	DN300	DN200
Wall thickness (mm)	4.78	5.16	6.35	5.16	4.78
Current MAOP (MPa)	7.136	7.136	7.136	4.612 / 4.200	4.200
“No Rupture” MAOP for 20 tonne excavator (MPa)	3.8	4.2	5.7	3.9	4.2
“No Rupture” MAOP for 35 tonne excavator (MPa)	2.8	3.1	4.2	3.0	3.4
“No Rupture” MAOP based on 30% hoop stress (MPa)	3.3	3.6	4.4	2.7	3.7

Table 7 Summary of Target MAOPs – DN400 Pipelines

DN400 Pipeline	5.7mm X70	6.4mm X60	6.8mm X70	7.7mm X60	8.1mm X70	9.5mm X60	8.85mm X80	9.7mm X70
Wall thickness (mm)	5.7	6.4	6.8	7.7	8.1	9.5	8.85	9.7
Current MAOP (MPa)	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6
“No Rupture” MAOP for 20t (MPa)	6.18	6.35	7.93	8.13	9.6	9.6	9.6	9.6
“No Rupture” MAOP for 35t (MPa)	4.96	5.11	6.38	6.62	8.16	8.85	9.6	9.6
“No Rupture” MAOP based on 30% hoop stress (MPa)	4.08	3.91	4.86	4.70	4.95	5.80	7.21	6.94

4.2.2 Energy Release Rate Compliance

Based on the No Rupture MAOPs above, energy release rates were calculated for likely MAOP scenarios for each pipeline. These are listed in Table 8.

Table 8 Calculated Energy Release Rates at Reduced MAOPs (Tiger teeth, B=1.3)

Pipeline					Energy Release Rate (GJ/s)	
Diameter	Wall thickness (mm)	Grade (API 5L)	Extent of T2 or S (km)	MAOP (kPa)	20t Excavator	35t Excavator
DN250	4.78	X46	0	7136	30.3	30.3
				5700	24.2	24.2
				4400	1.6	18.7
				3600	1.3	2.5
				3300	1.2	2.3
				2000	0.73	1.38
DN250	5.16	X46	1.2	7136	30.3	30.3
				5700	2.1	24.2
				4400	1.6	3.0
				3600	1.3	2.5
				3300	1.2	2.3
				2000	0.7	1.4
DN250	6.35	X46	2.4	7136	0.3	30.3
				5700	0.2	3.9
				4400	0.2	3.0
				3600	0.1	2.5
				3300	0.1	2.3
				2000	0.1	1.4
DN300	5.16	X42	2.1	4612	1.7	27.5
				4200	1.5	2.9
				3900	1.4	2.7
				3400	1.2	2.3
				3000	1.1	2.1
				2700	1.0	1.9
DN400	5.7	X70	0	9600	90.2	90.2
				6300	0.2	5.3
DN400	6.8	X70	0	9600	0.3	90.2
				6300	0.2	4.3
DN400	7.7	X60	0.7	9600	0.3	90.2
				6300	0.2	0.3

Note that DN400 pipelines at wall thickness greater than 7.7 mm are already compliant to energy release rate limits and hence are not shown in the table.

4.3 Current Configuration and MAOP/MOP Options

Schematic drawings have been created (refer Appendix A) to illustrate the current configuration of the RBP system as well as possible risk reduction reconfiguration options with reduced MAOP/MOPs.

Individual segments of the pipeline are discussed in the following sections, considering overall pipeline operational constraints and minimum customer delivery pressures in each segment.

4.4 DN300 Downstream Segment and DN200 (Eight Mile Plains to Gibson Island)

This section considers the downstream end of the Metro DN300 pipeline, approximately the last 13 km from Delavan Street to SEA, and the Gibson Island DN200 pipeline.

The principal load and main supply requirement in this section is Incitec at Gibson Island. An inlet pressure to the Gibson Island station of 2300 kPa is the practical minimum.

Based on system capacity modelling, the target MOP for no rupture compliance of 3.0 MPa can be implemented from approximately Eight Mile Plains, slightly upstream of the existing Mount Gravatt MLV. This MOP also results in an energy release rate that is compliant for T1 areas. Energy release rate compliance cannot be achieved for T2/S areas on the DN300 pipeline while maintaining existing supply. However, the energy release rate would be only marginally over the T2 limit and this is not a mandatory requirement for retrospective application of the current code. There is only one S zone of approximately 500 metres around KP 431 in this segment of the DN300 pipeline.

The downstream DN200 pipeline also achieves full No Rupture compliance and T1 energy release rate compliance at 3.0 MPa MOP.

To implement this pressure restriction, a new pressure regulator / spec break station would be required at the Eight Mile Plains location or alternatively at the existing Mt Gravatt MLV. Details of siting, land access and design are not in scope of this ALARP report and should be progressed in FEED.

4.5 DN300 Midstream Segment (Ellengrove to Eight Mile Plains)

This section comprises approximately 19 km from the Ellengrove inlet through to the proposed new Eight Mile Plains pressure regulating station described above.

There are 2 operational requirements driving pressures in this section, (1) a MAOP of 3900 kPa is required to supply the downstream Gibson Island practical minimum of 2300 kPa, and (2) and MAOP of approximately 4200 kPa is required to maintain the Ellengrove/Gold Coast distribution offtake at its requested practical minimum pressure of 4100 kPa. The distribution offtake has a contractual minimum of only 1500 kPa and it is possible that the 4100 kPa request could be negotiated to approximately 3900 kPa. Alternatives, such as supply from the DN400 system to the Ellengrove/Gold Coast system, are possible and would be the responsibility of the distribution system owner.

In this segment, an MOP of 4100 kPa would not achieve No Rupture compliance for the 20t or 35t excavator. Energy release rate would be compliant for T1 only. Other measures would be required for areas of the pipeline accessible to excavators.

An MOP of 3900 kPa would achieve No Rupture for a maximum 20t excavator, meaning only areas accessible to 35t excavators, and T2/S areas for energy release rate, would require additional measures to comply with no rupture and energy release rate requirements for a new pipeline.

To implement this pressure restriction, changes to set points at the existing Ellengrove inlet station would be required.

Further reduction of MAOP below 3900 kPa (e.g. to 3000 kPa to achieve 35t No Rupture) would impact supply to Gibson Island and would likely require significant capital expenditure such as construction of a looping pipeline or compression in the metro area. In this scenario the Eight Mile Plains regulator and Ellengrove MLV (described below) may not be required, however their costs are significantly lower than the compression option. These combination options are discussed further in Section 7.

4.6 DN300 Upstream Segment (Bellbird Park to Ellengrove)

This section comprises approximately 6 km at the upstream end of the DN300 pipeline. There are no customer offtakes in this section.

An MOP of 3000 kPa or lower could be implemented to achieve no rupture compliance for a 35t excavator, and energy release rate compliance for T1 only. Any future T2 or S areas would require additional measures, however no T2/S is currently identified.

To implement this pressure restriction, a new MLV would need to be installed in the DN300 pipeline upstream of the existing Ellengrove inlet tee. The MLV would be normally closed. This would require Bellbird Park to be inoperative and no flow in this section. Existing contracted flows on the upstream DN250 pipeline would need to be diverted into the DN400 pipeline as described further below.

Alternative combination scenarios are discussed in Section 7.

4.7 DN250 Pipeline

A MOP reduction on the DN250 pipeline could be implemented in a number of scenarios. The primary operational requirements on the DN250 pipeline are (1) to supply the various distribution offtakes, and (2) to transport Wallumbilla Run 1 and 2 gas at up to 30-40 TJ/d through to Brisbane.

To achieve objective (2) whilst applying significant pressure reductions, the DN250 flow is required to be redirected into the DN400 pipeline.

To enable DN250 flow to be regulated into the DN400 requires co-location of the DN250 and DN400 pressure regulation stations. The likely scenarios are Brightview or Gatton. Under both scenarios, the DN250 downstream pressure could be regulated to below 3.3 MPa to meet 30% hoop stress no rupture for the remainder of the DN250 through to Bellbird Park. This would also meet energy release rate compliance for T1 areas for all wall thicknesses and would meet T2/S criteria for the 6.35 mm wall thickness only. A minimum pressure to supply the distribution offtakes would be around 1800 kPa, however a 3000-3300 kPa pressure would provide more flexibility for operational purposes while still achieving HCA compliance.

All T2/S zones currently recorded in the DN250 SMS in the metropolitan area are in areas of 6.35 mm wall thickness so this scenario would achieve full HCA compliance downstream of the Brightview regulator station.

There is one S zone associated with a rural school at Jondaryan in the western RBP which has 5.16 mm wall thickness. MOP restriction is not feasible in this location.

To implement the DN250 MOP restriction the following would be required:

- DN250 pressure regulator skid at Brightview or Gatton
- Cross-connect DN250 to DN400 at the same location, to flow DN250 gas into the DN400 pipeline downstream of its pressure regulator
- Operation of the existing DN250 compressors at Kogan and Oakey, including upgrade to intermittent or continuous duty classification from the current standby classification, to provide sufficient pressure for the cross connect regulator skid.

Alternatives and combination scenarios are discussed in Section 7.

4.8 DN400 Pipeline

A MOP reduction could be applied to the DN400 system from either Gatton or Brightview through to Swanbank and Ellengrove. This includes 38.7 km of HCAs, of which 17.1 km is currently non compliant for no rupture.

The primary customer delivery requirement is for Swanbank Power Station which requires 4800 kPa. For this reason the furthest upstream a MOP reduction could be imposed would be Gatton compressor station. However considering the interconnection requirement with the DN250 pipeline a 6300 kPa at Brightview is the preferred option.

The DN400 regulator location for pressure reduction is interdependent with the DN250 pipeline pressure reduction options, as the cross connection from DN250 to DN400 can only occur at or downstream of the DN400 regulation.

Reduction to 6300 kPa MOP, with regulation at Brightview, would reduce the non-compliance for HCA no rupture to 3.4 km and would achieve T1 energy release rate compliance for pipe down to 6.8 mm wall thickness and T2/S energy release compliance for 8.85 and greater wall thickness (which covers all T2/S locations).

To implement this MOP restriction a pressure reduction skid would be required to be constructed at Brightview.

5 Pipe Replacement / Relocation / Land Use Modification

5.1 General

Replacement of non-compliant pipe with new HCA-compliant pipe is possible for all pipelines. Depending on the pipeline segment in question, this may require either removal of the segment from service for construction works, or the use of hot tap, bypass and stopple techniques to maintain flows while tying in new pipe.

Pipe replacement options for each segment are discussed below.

5.2 DN300 / DN200 Pipe Replacement

The following non-compliant HCA pipe (not complying with AS 2885.1 Clause 4.7.2 and 4.7.3) is identified as per Appendix B.

Table 9 Pipe Replacement Quantities - Metro

Pipeline Segment	Non Compliant HCA Length	Number of segments	Number of bypass and double stopple tie ins	Number of crossings (road / rail / water)	Comment / Alternative
DN200 Gibson Island	2.1 km	1	2	1	Partially looped by ML1
DN300 Downstream (Eight Mile Plains to SEA)	9.8 km (5.5 km excl ML1 section)	9 (7)	18 (14)	32 (26)	ML2 construction would complete looping.
DN300 Midstream (Ellengrove to Eight Mile Plains)	12.3 km	13	26	39	ML3 future looping
DN300 Upstream (Bellbird Park to Ellengrove)	4.4 km	3	6	8	Already looped by CEP

In the DN300 Metro pipeline some sections are already looped by the DN400 system (upstream of Ellengrove and downstream of Preston Road / Kate Street).

In general, the most economical option combining pipe replacement and/or abandonment of the existing pipeline segments has been developed to achieve the aim of removing all non-HCA compliant pipe from service. These combinations are considered for ALARP analysis.

DN200 Gibson Island: Replace lateral.

DN300 Downstream: Segmented DN300 replacement x 7, 5.5km total, plus abandonment of ML1 looped section; OR complete ML2 construction between Eight Mile Plains and Preston Road, and abandon DN300 and provide new customer offtakes from looping pipeline.

DN300 Midstream: Segmented DN300 replacement x 13 for 12.3 km; OR complete ML3 construction between Ellengrove and Eight Mile Plains and reduce pressure in DN300.

DN300 Upstream: Segmented DN300 replacement x3 for 4.4 km total, OR install MLV and abandon DN300 (Already looped). Relocate Bellbird launcher to Ellengrove. However, this would have undesirable impacts on the upstream DN250 pipeline making pigging difficult.

Combinations and options are set out in Section 7.

5.3 DN250 Pipe Replacement

Pipe replacement in HCAs on the DN250 pipeline is possible without multiple hot taps and bypasses, since the DN250 is fully looped by the DN400 pipeline. Supply interruptions are less critical, with the exception of Riverview distribution offtake which may need an alternative supply from the DN400 pipeline to be constructed.

Table 10 Pipe Replacement Quantities – DN250

Pipeline Segment	Non Compliant HCA Length	Number of segments	Number of bypass and double stopple tie ins	Number of crossings (road / rail / water)	Comment / Alternative
DN250 Gatton to Bellbird	19.7 km	16	<32	TBC	DN400 looping exists
DN250 Wallumbilla to Gatton	15.6 km	14	<28	TBC	DN400 looping exists

The DN250 pipeline could also be abandoned in the HCAs or potentially for the entire length from Gatton or Brightview to Bellbird Park. Brightview, Riverview and Redbank would need supply from DN400 to be commissioned in this scenario. A level of redundancy would be lost, as the ability to back feed DN250 supply out to Sandy Creek from Redbank would no longer be possible. (This was required during Toowoomba and Marburg repairs in recent years and is likely to be used again for future shutdowns of the pipeline.) There would also be no redundancy of the DN400 pipeline through to Brisbane in the event of any issue or repair requirements on the DN400.

Any abandonment of the DN250 pipeline would likely lead to severe curtailment of shippers in Run 1 and Run 2 at Wallumbilla, as there is insufficient load upstream on the DN250 pipeline without a flow path through to the Metro system.

5.4 DN400 Pipe Replacement

DN400 pipe replacement is possible in HCAs. The DN400 system is more critical than the DN250 and hot tap and bypass arrangements would be required for cut over to replacement pipe. The strategy would be to replace pipe in the same right-of-way with new HCA-compliant pipe for all non-compliant HCA zones.

Table 11 Pipe Replacement Quantities – DN400

Pipeline Segment	Non Compliant HCA Length	Number of segments	Number of bypass and double stopple tie ins	Number of crossings (road / rail / water)	Comment / Alternative
DN400 Gatton to Swanbank	17.1 km	9	18	TBC	-
DN400 Wallumbilla to Gatton	23.1 km	15	30	TBC	-

Scope of work and budget estimates for this are compared in the options analysis section of the report.

5.5 Pipeline Relocation

In the metropolitan areas, it is not feasible to relocate the RBP out of any HCA zones, as the RBP is required to supply the suburban distribution networks and major customers within the metropolitan areas.

It may be possible to partially reroute to avoid S and T2 zones, however the majority of T1/T2 areas cannot realistically be avoided.

In non-metropolitan areas, such as isolated rural towns with T1, I/HI or occasionally S location class, relocation of pipeline to avoid the HCAs is possible but will cost more than direct pipe replacement. Extra length will generally be required as well as a new easement, compared to replacement in the same ROW.

The option of relocation of pipeline has not been considered further as it will always be more expensive than pipe replacement in the same ROW.

5.6 Modification of Land Use

In the metropolitan areas, it is not considered feasible to modify land use to remove HCAs, as land within the measurement length for most of the pipeline is fully developed. Modification of land use would require sterilisation of all land within the pipeline measurement length.

For non-metropolitan areas, this option would likely require APA to purchase all affected properties within the measurement length and remove the population. Where the HCA includes townships, schools and industrial areas this would be impossible to achieve without major impacts to local communities and significant rezoning / replanning by councils.

As a guide, the quantity of land required to be sterilised for each pipeline is summarised in Table 12.

Table 12 Land Modification Estimates

Pipeline Segment	Measurement Length	Approx. Land Area Affected per km	Approx Total Land Area Affected by HCA
DN250	272 m	54.4 ha	1920 ha
DN400	472 m	94.4 ha	3795 ha
DN300	261 m	52.2 ha	1383 ha
DN200	167 m	33.4 ha	70 ha

6 Increased Physical and Procedural Protection Measures

6.1 Physical Protection – Separation

Typical protection measures are discussed as follows:

6.1.1 Burial - Depth of cover

Typical threats relevant to the RBP include other utilities and road works excavations. For other utilities such as water, sewerage, telecommunications, electricity and gas distribution, typical trenched cover depths can require excavation depths 1 to 1.6 metres. For some gravity sewer, stormwater and power pole threats, depth could be significantly greater and therefore a substantial cover increase would be required to eliminate the threats.

Increasing depth of cover of an existing pipeline is occasionally done to lower a pipeline beneath an obstacle such as a new road or rail line but is generally not practical for the lengths of existing pipeline being considered and the depths required. In-service lowering requires significant excavation of the pipeline upstream and downstream of the obstacle to provide flexibility, in the order of a few hundred metres. In built-up areas this is not possible. In rural areas this may be possible in isolated areas of straight pipe.

Also, due to the age and condition of the original RBP segments, full coating removal, inspection and NDT and recoating of the pipeline would be required. In effect the cost of this work to increase cover depth would be similar to the cost of constructing new pipe, with the exception of the hot tap and stopple bypasses and tie-in work.

For the purpose of ALARP assessment this option is costed at the same rate as pipe replacement however it is less effective as the pipeline still does not meet the HCA compliance requirements.

6.1.2 Exclusion

Partial fencing or exclusion could be possible in some areas such as parks and reserves, to prevent 3rd party excavation access to the pipeline. In some of these areas the pipeline is in a walkway corridor between residential properties and access exclusion could be considered such as bollards, to allow only pedestrians and cyclists on the pathway. This would not eliminate the risk entirely as it is likely that other parties such as councils and electricity and water authorities may also require access to the locations.

Parks and reserves, however, are not the most exposed sections to 3rd party threats. A large portion of the RBP is within public road reserves, with no easement, which cannot be fenced off and cannot have access prevented for other utilities. Much of the remainder is in easement in private properties, which would be very difficult to exclude access to without resorting to purchase of a large amount of land.

It is noted that some areas, namely minor suburban streets in built-up residential areas, private residences / backyards, and under certain overhead power lines, access restrictions already prevent large excavators e.g. 35 tonne from accessing the ROW. This has been considered already in the assessment of non-compliant HCAs.

AS 2885.1 also mentions barrier protection for at-risk above ground facilities as an exclusion control, however this is is already implemented for APA above-ground sites and is not considered relevant for buried pipeline 3rd party risks.

6.2 Physical Protection - Resistance to Penetration

Resistance to penetration suitable for HCA compliance could be achieved in a number of ways:

- Increased wall thickness - not feasible for the existing pipelines. Refer to the pipe replacement scenarios.
- Concrete protection slabs – feasible for existing pipelines and known to be effective against excavators and vertical augers.
- Alternative protection slabs such as HDPE. These materials are available from existing suppliers however their effectiveness is not yet known.

Concrete protection slabs are typically installed at 3rd party crossings, however this report considers the widespread implementation of slab protection in all HCAs.

Refer to Section 3.4 for the quantities of non-compliant HCA pipe requiring treatment.

Concrete protection slabs are feasible to install above existing pipelines in most locations, and may be used in combination with other options such as MOP reduction or pipe replacement. Combination scenarios are considered in Section 7.

Some of the approaches considered include:

- Slab protection of all non-compliant pipe in HCAs where excavator access is possible
- Slab protection only of areas where other measures e.g. MOP reduction are not possible (recommended)
- Slab protection of areas where 35t excavators can access but other measures such as MOP restriction achieve compliance only for smaller excavators (recommended)
- Slab protection of T2 and S areas where energy release rate limits cannot be met by other methods such as MOP restriction (recommended)

Alternative slab materials may be implemented if trials prove their effectiveness. Lightweight HDPE slabs would be significantly cheaper and faster to install than conventional concrete slabs.

6.3 Procedural Protection – Awareness

APA already has a range of procedural awareness measures in place as documented in the Land Management Plan. These include:

- Landowner liaison
- 3rd party liaison
- Community awareness
- One-call DBYD
- Pipeline markers / signage
- Activity agreements / corridor agreements with roads, utilities etc
- Planning notification zone in place with local authorities. At present APA receive development approval notifications from Brisbane City Council and Ipswich City Council for works with 200 metres of the pipeline. BCC and ICC are the two local areas with the most significant metropolitan encroachment. APA's Lands department is working to expand the notification zone to at least equal the measurement length of the pipelines and to implement agreements with other councils.

As per existing SMS actions for the RBP, all of the procedural measures should be continued with a high level of focus on the HCAs.

6.4 Procedural Protection – Detection

APA has a range of procedural detection measures in place including:

- Patrolling - Daily (7 days a week) road patrol in all high consequence areas; Weekly patrol in non-HCA metro areas (bushland etc.); Monthly aerial patrol (not suburban areas); 6-monthly detailed ‘audit’ patrol.

Additional detection measures could be considered including:

- Increased patrol activity beyond once per day, perhaps 2 or 3 patrols per day. However, this is not considered to provide any real benefit above the existing daily (7 days per week) patrol regime.
- Increased surveillance by satellite imagery, drone / helicopter patrolling, CCTV, or other technology. However, these increases in monitoring are considered unlikely to provide significant additional benefit beyond the existing patrol regime. Drones or UAVs should be considered to assist with ground patrols, if viable, especially where the pipeline traverses suburban residential properties.
- Remote intrusion monitoring using fibre optic cables. This is an emerging technology for pipeline excavation detection, however would be costly and time consuming to implement on the existing pipeline alignment through suburban areas. It is not currently established sufficiently for off-the-shelf deployment but warrants investigation and study for possible future implementation for the RBP.

7 RISK ASSESSMENT

7.1 Method

The risk assessment methodology of AS 2885.1-2012 has been adopted in this study. Risk assessment has been carried out on a generic RBP pipeline that is non-compliant to the HCA requirements, both ‘as is’ and with the various mitigation options applied.

Where required, the LOPA (Layers of Protection Analysis) technique has been applied to differentiate results within particular likelihood and risk levels. LOPA worksheets are contained in the RBP Metro SMS report 320-RP-HS-0001.

7.2 Generic Threats

Three threats have been considered, which cover all Intermediate-ranked external interference threats from the RBP SMS workshops. These are:

- 10-20t excavator engaged in maintenance or construction of a foreign utility such as water, sewerage, electricity or telecoms. This excavator when equipped with tiger teeth may cause a leak which may ignite and lead to a few (one or two) fatalities amongst the work crew.
- Note that an excavator up to 20 tonnes will generally result in a leak, as the maximum hole length from this machine is generally less than the CDL. However, the ‘No Rupture’ factor of 1.5 x is not met.
- 35t excavator engaged in major roadworks or construction earthworks, using tiger teeth. This excavator may cause a full-bore rupture which if ignited in a T1 or T2 location could result in multiple fatalities including members of the public.
- Vertical auger (truck-mounted pendulum auger), engaged in replacement or construction of power poles or street lighting or similar, likely to be equipped with a 50 mm pilot bit that may result in a leak and potentially one or two fatalities.
- Horizontal directional drill engaged in construction of new communications or electricity cables, typically at road crossings or intersections. This threat was only ranked as Low in the SMS and a LOPA is provided in the Metro SMS Report. However, it has been included in this ALARP study for completeness.

7.3 Risk Reduction Scenarios

Four risk reduction scenarios have been considered, as per the detail in Sections 4, 5 and 6 of this report, including:

- MAOP / MOP Reduction, in order to increase the critical defect length to meet the no rupture requirements, and also to slightly decrease the energy release rate in a loss of containment;
- Pipe replacement with modern ‘no rupture’ pipe, which is taken to include removal of all non-compliant pipe from service. The replacement pipe would be designed to be fully compliant to current standards;
- Increased physical protection by the installation of barriers such as concrete slabs, encasement or similar, at all locations accessible by excavators and augers. This does not achieve the ‘no rupture’ or energy release rate requirements but greatly reduces the likelihood of mechanical damage occurring in the first place.
- Combination of partial MOP reduction, e.g. to 4200 kPa in the Metro pipeline, which does not achieve full no rupture compliance but does reduce consequences, with slab protection at all exposed areas such as road crossings.

Table 13 summarises the risk reductions available for each option. Detailed risk assessment records are located in Appendix E.

Notes on Table 13:

- MOP reduction is considered preferable where it is feasible, as it removes the highest consequence (rupture). This cannot be achieved while maintaining supply over the entire pipeline length, but is possible in sections.
- Where MOP reduction is impractical, slab protection is preferred.
- When MOP reduction is implemented, the risk rank for 35t excavator becomes Low, compared to Intermediate for a 20t excavator. While counter-intuitive that a larger threat results in a lower risk, this is a result of the Hypothetical likelihood which is not altered by the MOP reduction.

Table 13 Compliance and Risk Assessment of Treatment Options (Typical RBP Metro DN300 or DN250)

Option	No Rupture compliant	Energy Release compliant	20t Excavator Risk	35t Excavator Risk	Vertical Auger Risk	HDD Risk	Comment
Current Status	No	No	Intermediate (Major/Remote)	Intermediate (Catastrophic/ Hypothetical)	Intermediate (Major/Remote)	Low (Major/ Hypothetical)	With existing controls
MOP Reduction to achieve >1.5 CDL factor or 30% SMYS (recommended where possible)	Yes	T1 only	Intermediate (Major/Remote)	Low (Major/ Hypothetical)	Intermediate (Major/Remote)	Low (Major/ Hypothetical)	Removes catastrophic rupture consequence; minor improvement on other threats
Pipe Replacement	Yes	T1 and T2	Negligible (Minor/Remote)	Negligible (Minor/ Hypothetical)	Low (Major/ Hypothetical)	Low (Major/ Hypothetical)	
Slab protection (recommended where MOP reduction not possible)	No	No	Low (Major/ Hypothetical)	Intermediate (Catastrophic/ Hypothetical)	Low (Major/ Hypothetical)	Low (Major/ Hypothetical)	Hypothetical threats become close to non-credible (2 orders of magnitude improvement within Hypothetical range)
Partial MOP reduction to achieve CDL factor between 1 and 1.5, plus slab exposed areas (recommended for some sections)	No	T1 only	Low (Major/ Hypothetical)	Low (Major/ Hypothetical	Low (Major/ Hypothetical)	Low (Major/ Hypothetical)	While not achieving No Rupture compliance, the most likely large excavator threat consequence becomes a leak only.

(Refer Notes on previous page)

8 ALARP ANALYSIS

8.1 ALARP Approach

The approach taken to ALARP in this study is as follows:

- All options to reduce risk are considered, with the intention of demonstrating that only mitigation measures which have a cost 'grossly disproportionate' to the benefit are not implemented.
- The 'maximum justifiable spend' approach previously used in some safety management studies is not adopted. Low probabilities mean that factoring benefits is unreliable for high-consequence events.

8.2 Benefits Gained from Reduced Risk

The benefits gained from each of the three primary risk reduction measures are summarised in Table 13 .

Other measures including improvements to procedural controls (landowner and 3rd party liaison, signage, patrols) are not specifically discussed as these are already identified as SMS actions and their costs are not material in comparison to the three main options above.

8.3 Cost Estimates of Risk Reduction Measures

High-level cost estimates have been prepared for each mitigation option using APA's experience of construction costs for pipelines and facilities. These estimates are considered sufficient for the purpose of comparing options but would need to be further developed including engineering design and scoping before being used for budget setting.

8.4 Summary of Mitigation Options and Costs

The overall options and costs for risk mitigation are summarised in Table 14 below.

Table 14 Costs and Scopes of Risk Mitigation Options

PIPELINE			MAOP / MOP REDUCTION				PIPE REPLACEMENT				SLAB PROTECTION				
Segment	Segment Name	Non compliant HCA Length (km)	Scope	Benefit	Cost	Recommended	Scope	Benefit	Cost	Recommended	Scope	Benefit	Cost	Recommended	Notes
1	RBP DN250 Wallumbilla-Gatton	15.6	Not feasible	-	-	No. Not feasible with current operational requirements.	15.6 km of pipe in 14 sections	Full NR / ERR compliance;	$ 32,000,000	No. Cost disproportionate to benefit.	Slab 15.6 km	Reduces likelihoods to Hypothetical or better.	$ 7,800,000	Yes. However, HCAs in this segment are mostly rural I and HI zones and lower priority than metro T1/T2.	Rural HCAs are to be prioritised appropriately for slab protection.
2	RBP DN250 Gatton-Bellbird	19.7	Construct DN250 PRS @ Brightview Construct DN250 to DN400 Cross connect @ Brightview (Also requires DN400 PRS)	Full NR and ERR compliance (T1 for all pipe types, T2/S for HW only which covers all T2/S) at MOP of 3300 kPa d/s of Brightview Leak only; catastrophic rupture not credible	$ 4,000,000	Yes	19.7 km of pipe in 17 sections	Full NR / ERR compliance;	$ 60,000,000	No. Cost disproportionate to benefit.	Slab 19.7 km	Reduces likelihoods to Hypothetical or better.	$ 9,900,000	No. Consider targeted slabbing at exposed T1 areas and all T2/S, and all HCAs upstream of PRS.	Consider increased DN250 compressor utilisation at Kogan and Oakey and need for full MAOP upstream.
3	RBP DN300 Bellbird - Ellengrove	4.4	Construct new MLV @ Ellengrove Set point adjustment @ BBP	Full NR and ERR compliance at MOP of 3000 kPa. (No T2/S in this segment) Leak only; catastrophic rupture not credible	$ 1,000,000	Yes	Replace 4.4 km in 3 sections	Full NR / ERR compliance;	$ 14,000,000	No. Cost disproportionate to benefit.	Slab 4.4 km	Reduces likelihoods to Hypothetical or better.	$ 2,200,000	No. MOP reduction achieves NR and T1 ERR compliance and there is no T2 or S.	
4	RBP DN300 Ellengrove to Mt Gravatt	12.3	Reduce pressure set points @ ELG/ BBP to 3000 kPa. Construct compressor station at Preston Road to supply d/s customers.	Full NR and T1 ERR compliance at MOP of 3000 kPa. T2/S still non compliant. Leak only; catastrophic rupture not credible	$ 25,000,000	No. High cost and undesirable to install compressors in metro area. Partial MOP reduction possible in conjunction with slabbing	Replace 12.3 km in 13 sections	Full NR / ERR compliance;	$ 37,000,000	No. Cost disproportionate to benefit.	Slabs 12.3 km	Reduces likelihoods to Hypothetical or better.	$ 6,200,000	Yes	Combination recommended - partial MOP to the extent possible while maintaining supply, plus slab protection of exposed areas.
5	RBP DN300 Mt Gravatt to SEA	9.8	Construct DN300 PRS at Eight Mile Plains. MOP of 3000 kPa downstream.	Full NR and T1 ERR compliance at MOP of 3000 kPa. T2/S small area non ERR compliant. Leak only; catastrophic rupture not credible	$ 2,000,000	Yes	Replace 9.8 km in 9 sections	Full NR / ERR compliance;	$ 30,000,000	No. Cost disproportionate to benefit.	Slab 9.8 km	Reduces likelihoods to Hypothetical or better.	$ 4,900,000	No (for widespread slabbing). Localised slab protection recommended near Belmont State School.	
6	RBP DN200 Gibson Is	2.1	MOP reduction provided by upstream Eight Mile Plains. Zero incremental cost.	Full NR and T1 ERR compliance at MOP of 3000 kPa. (No T2/S in this segment) Leak only; catastrophic rupture not credible	$ -	Yes	Replace 2.1 km in 1 section	Full NR / ERR compliance;	$ 6,000,000	No. Cost disproportionate to benefit.	Slab 2.1 km	Reduces likelihoods to Hypothetical or better.	$ 1,100,000	No. MOP reduction is preferable and achieved at no additional cost when DN300 PRS is provided.	
7	RBP DN400 Wallumbilla to Gatton	23.1	Not feasible.	-	-	No. Not feasible with current operational requirements.	Replace 23.1 km in 15 sections	Full NR / ERR compliance;	$ 57,000,000	No. Cost disproportionate to benefit.	Slab 23.1 km	Reduces likelihoods to Hypothetical or better.	$ 11,600,000	Yes. However, HCAs in this segment are mostly rural I and HI zones and lower priority than metro T1/T2.	Rural HCAs are to be prioritised appropriately for slab protection.
8	RBP DN400 Gatton to Moggill	8.8	Construct DN400 PRS @ Brightview with MOP of 6300 kPa	Full NR and T1 ERR compliance at MOP of 6300 kPa. Leak only; catastrophic rupture not credible. 3.4 km remains non compliant upstream of Brightview	$2,000,000	Yes	Replace 8.8 km in 9 sections	Full NR / ERR compliance;	$ 27,000,000	No. Cost disproportionate to benefit.	Slab 8.8 km (Slab 3.4 km if PRS installed)	Reduces likelihoods to Hypothetical or better.	$ 4,400,000	Yes, but in HCAs upstream of Brightview only.	Rural HCAs are to be prioritised appropriately for slab protection where MOP is not reduced.
9	RBP DN400 Swanbank Lateral	8.3	MOP reduction provided by upstream Brightview	Full NR and ERR compliance at MOP of 6300 kPa. Leak only; catastrophic rupture not credible.	$ -	Yes	Replace 8.3 km in 5 sections	Full NR / ERR compliance;	$ 25,000,000	No. Cost disproportionate to benefit.	Slab 8.3 km	Reduces likelihoods to Hypothetical or better.	$ 4,200,000	No. MOP reduction is effective.	
10	RBP DN400 Collingwood Ellengrove	0.0	MOP reduction provided by upstream Brightview	6300 kPa easily achieves NR and ERR requirements.	$ -	Yes	Not required		$ -	No	Not required		$ -	No	

Notes on cost estimate basis:

Slab protection	All	$	500,000	per km
Pipe replacement	DN200/250 'standard' rate	$	2,000,000	per km
Pipe replacement	DN400 'standard' rate	$	2,500,000	per km
Pipe replacement	All sizes 'metro' rate	$	3,000,000	per km
Station construction	Regulator station	$	2,000,000	each
Station construction	MLV station	$	1,000,000	each
Station construction	2-unit compressor station metro	$	25,000,000	each

8.5 Recommended Mitigation

Based on the risk reduction benefits and the estimated costs for each option, APA's recommended mitigation strategy is as outlined in Table 14 by the green highlighted rows. Refer to Table 14 and Appendix E for further information. The following sections outline the study recommendations.

8.5.1 Reduce MOP to meet HCA code requirements

In general it is the recommendation of this study to implement MAOP or MOP reduction where it is feasible to do so, sufficient to achieve No Rupture compliance by increasing the CDL to above 1.5 x the largest credible excavator defect length. This level of MOP reduction typically also achieves energy release rates suitable for T1 location class and therefore compliance with AS 2885.1 Clause 4.7 requirements as if for a new pipeline.

Where MOP reduction achieves the 1.5 CDL factor, localised additional physical protection is still recommended in conjunction with the MOP reduction in the following circumstances:

- In T2 and S location classes, if the energy release rate at the reduced MOP still exceeds 1 GJ/second;
- At identified hot-spot locations where the pipeline may be particularly exposed to external interference such as road crossings, changes of direction and branch connections within road reserve.

Widespread slab protection other than the above is not recommended where the 1.5 x CDL factor is achieved by MOP reduction. The cost of widespread slabbing over many kilometres is grossly disproportionate to the incremental risk reduction gained.

8.5.2 Partially reduce MOP in conjunction with slab protection

In some locations, such as Ellengrove to Eight Mile Plains, it is not feasible to implement MOP reduction sufficient to achieve the HCA code requirements for new pipelines while maintaining existing supply to customers.

In this circumstance it is recommended to implement an MOP reduction to the lowest practical and suitable pressure while maintaining existing supply. Although this does not achieve compliance with the HCA requirements for new pipelines with a 1.5 CDL factor, the partial MOP reduction improves the CDL to between 1.0 and 1.5 and therefore makes catastrophic rupture significantly less likely, and also reduces the consequence of a leak failure due to lower pressure in the pipeline.

In these locations, since the MOP reduction does not achieve full no rupture compliance as required for a new pipeline, it is also recommended to install barrier protection (concrete slabs or similar) above the pipeline to reduce the likelihood of external interference threats reaching the pipeline. This slab protection is recommended to cover all HCA zones where excavator and auger access is credible, including road reserve, parkland and private properties other than suburban residential yards.

The partial MOP reduction with the additional slabbing installation should prevent any mechanical equipment threat causing a pipeline rupture with ignition.

8.5.3 Slab protection only

In locations where MOP reduction is not possible without impacting supply to customers, this study recommends installation of barrier protection to reduce the likelihood of external threats reaching the pipeline.

This includes the DN250 and DN400 pipelines west of the proposed Brightview pressure regulating station. There is over 38 km of HCA pipe in this category. Much of this is rural I or HI zones with only a small amount of T1 and/or S zones around the towns of Dalby, Bowenville, Jondaryan and Toowoomba. It is recommended that the slab protection be appropriately prioritised in conjunction with the metropolitan slab protection as described in Sections 8.5.1 and 8.5.2, with the general approach of Sensitive zones first, T1 second, and rural I/HI third due to the differing societal consequences associated with each location class.

8.6 Options Not Recommended

Pipe replacement or relocation is not recommended by this study. While theoretically possible, the costs are considered grossly disproportionate to incremental benefit achieved. Costs of replacing or relocating all HCA pipe are estimated to be in excess of $250,000,000 as per Table 14.

The previously proposed RBP metro looping project (Stages 2 and 3) is part of the pipe replacement strategy and is therefore not considered as a viable option for risk reduction purposes due to the high capital cost compared to MOP reductions and slab protection. It is therefore recommended that the RBP metro looping stages 2 and 3 are deferred until such time as there is a commercial demand for increased capacity in the metropolitan area.

8.7 ALARP Considerations

In consideration of recent pipeline industry research on ALARP principles, an industry guidance questionnaire developed and under consideration for a future revision of AS 2885 has been considered in this study.

The checklist has been answered on the basis of APA’s recommended approach combining MAOP/MOP reductions and slab / barrier protection for the high consequence areas of the RBP as set out in Section 8.5. The aim is to demonstrate that this approach is rigourously considered and achieves ALARP and that the costs of further measures such as pipe replacement are grossly disproportionate to the risk reduction achievable.

The ALARP checklist is detailed in Appendix F.

8.8 ALARP Conclusion

This study has considered all risk reduction options for the RBP HCAs as required by AS 2885.1 Clause 4.7.4.

Where MOP reduction is completed such that the No Rupture requirements for new HCA pipelines are achieved, a full-bore rupture is effectively no longer a credible outcome from the relevant threats in these sections. Where effective slab protection is installed the likelihood of excavators and augers contacting or damaging the pipeline is reduced to the low end of the Hypothetical range.

After considering all options in this study, the recommended combination of MOP reductions and physical barrier protection is believed to substantially reduce the risk levels associated with external interference threats. The remaining options to further reduce risk are abandonment and/or pipe replacement and the costs associated with these options are considered grossly disproportionate to the incremental risk reduction benefit.

It is therefore concluded that the recommended combination of MOP reduction and physical barrier protection has achieved reduction of risks to as low as reasonably practicable, in accordance with the requirements of AS 2885.1 and the Safety Management Study for the pipeline.

9 DISCUSSION AND CONCLUSIONS

9.1 General

Overall, in consideration of the highly populated location and potential risks to the community and to APA, this study recommends that measures are taken to reduce risks to ALARP in all high consequence areas as per AS 2885.1 – 2012.

9.2 Recommended Approach

As outlined in Section 8, the proposed approach for risk reduction involves:

- Reduction in MOP in the DN250 pipeline from Brightview to Bellbird Park to 3300 kPa – refer Section 4.7
- Reduction in MOP in the DN400 pipeline from Brightview to Swanbank and Ellengrove to 6300 kPa – refer Section 4.8
- Reduction in MOP in the DN300 Metro pipeline from Bellbird Park to Ellengrove to 3000 kPa (refer Section 4.6), from Ellengrove to Eight Mile Plains to 4200 kPa (Section 4.5), and from Eight Mile Plains to SEA to 3000 kPa (Section 4.4)
- Installation of slab protection to other HCA pipe that is exposed to excavator/auger threats on a priority basis, commencing with the DN300 Metro area between Ellengrove and Eight Mile Plains. More detail on this is shown in section 9.3 below.

The above approach will effectively mean clauses 4.7.2 and 4.7.3 of AS2885.1 for non rupture and energy release in HCA are met in the majority of populated areas of the RBP.

The approach taken in reaching ALARP has some conservatism (safety margin) builtin. A bucket force multiplier of 1.3 has been used in determining penetration resistance. In addition, the protection from pipeline rupture was determined based on the critical defect length being not less than 150 percent of the axial length of the largest defect. In the section between Ellengrove and Eight Mile Plains, the maximum defect length caused by a single tooth of a 20 T and a 35T excavator is less than the critical crack length but doesn't achieve the 150% factor. Additional protection through slabbing will be provided to reach ALARP.

The implementation of this recommendation will require new pressure regulating facilities at Brightview and Eight Mile Plains and a new MLV at Ellengrove to be designed and constructed. Detailed design and construction should follow normal APA project processes.

The Eight Mile Plains facility should be considered for use as the MAOP spec break as well as the MOP change, such that the existing Mt Gravatt MAOP spec break can be removed.

9.3 Slabbing Implementation

Slab protection is recommended for areas where 20 t and 35t excavators can access but other measures such as MOP restriction achieve compliance only for smaller excavators. In addition, slab protection of T2 and S areas is recommended where energy release rate limits cannot be met by other methods such as MOP restriction and slab protection is required in areas where other measures e.g. MOP reduction are not possible. Slabbing is not proposed to be installed where depth of cover over the pipeline is such where third party threats are not credible.

In the metropolitan areas there are likely to be some restrictions on slabbing in road reserves, due to the presence of other services and utilities in the area. For example, Brisbane City Council has a standard allocation of road reserve space for electricity, gas, communications, water and sewer assets and installation of conventional slabs may require permission of the Council and the other asset owners.

Alternatives to conventional concrete slabs should be investigated, such as concrete encasement of the pipe, lightweight plastic slabs and other options. Trials are recommended, in order to determine effectiveness of alternative measures against excavators and augers.

Slab protection (or alternative barrier protection) should continue to be implemented across the RBP. The highest priority sites are already identified as road crossings and/or pipeline direction changes within road reserves, where exposure to other utility or road earthworks is greatest. Pipe in T2 and S location classes is also high priority due to the greater consequences in these locations. Finally in the Ellengrove to Eight Mile Plains section, areas accessible by 35 tonne excavators should be prioritised as this section cannot achieve HCA requirements for large excavators.

A detailed scoping exercise is required to establish exact locations and methods of slab protection, considering the existing pipeline protection, depth of cover, excavator accessibility, and type of ground surface above (bitumen road, concrete path, grass verge, etc.).

9.4 Procedural Protection

APA should continue to carry out all operational and procedural protection as identified in the SMS. There are no significant cost hurdles to maintaining and improving the existing procedural regime. APA should continue the daily right-of-way patrols; regular detailed right-of-way audits; active monitoring of development activity; dial before you dig participation; third party and landowner liaison, and other activities as per the Land Management Plan.

Improvements to the ground patrol regime should be investigated further, including the use of unmanned aerial vehicles (drones) for patrolling areas inaccessible to normal road patrols such as suburban residential properties.

A number of related improvements to procedural protection measures were identified in the 2014 and 2015 SMS reviews and these should be implemented within appropriate time frames as per the SMS Actions.

9.5 Review and Update of ALARP Study

This ALARP study should be reviewed regularly, as a minimum at every SMS Review (5-yearly operational full reviews and also at other SMS occasions such as encroachment or land use change.

Potential future refinements and improvements to the ALARP study could include the following items:

- Collection of further Charpy test data from available vintage line pipe, since the CDLs used are based on very limited Charpy testing. Additional testing is recommended as per the RBP Fracture Control Plan to provide additional certainty on the CDLs and therefore the rupture compliance. However, it is not envisaged that the overall outcomes of this study will be significantly changed as a result of the additional testing.
- More comprehensive understanding of excavator and auger threats in RBP HCAs. Improvements to earthworks machinery data collection are recommended such that all sightings on or near the pipeline corridor are reported to a central database including machine size, bucket and tooth type and relevant information on the works being done.
- Improvements to APA's GIS to include more reliable and up to date information on slab extents, pipe type, casings, signage and other measures relevant to external interference protection.
- Site confirmation of pipe location in proposed slabbing areas in the Metro to confirm depth of cover, position in road reserve or property (e.g. under footpath or bitumen or nature strip), and detailed recording of signage.
- In scenarios where only a single point of a tiger tooth can penetrate the pipeline, clarification in AS 2885 of the maximum defect length calculation methodology. This is likely to have only

minor impact on the RBP outcomes as in most scenarios, with B=1.3, both points of a tiger tooth can penetrate.

9.6 Other Recommendations

Other recommendations of this study are as follows:

- Publish the revised location class data following the detailed ALARP assessment to the RBP SMS Database and process MOC approval for necessary changes to the works management system.
- Develop a procedure for future management of the MOP restrictions including any specific procedural controls to be adopted for the duration of raised MOPs, e.g. during pigging.
- Review and update existing pigging procedures to account for the new MLV and pressure regulator facilities.
- Continue to manage pipeline integrity considering the full existing MAOP of the pipelines in terms of ILI, anomaly assessment and defect repair.

9.7 Conclusion

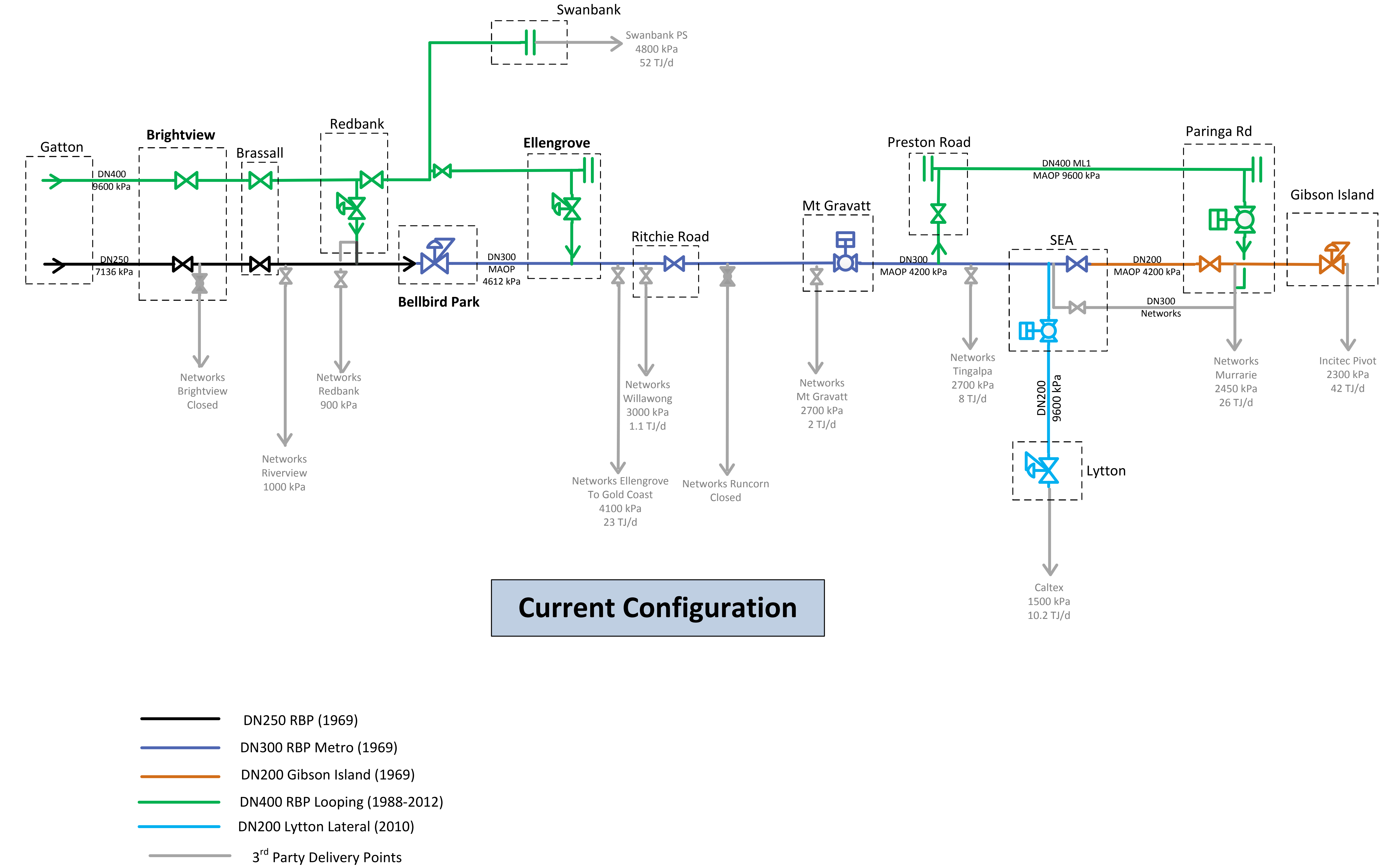
After assessing all feasible risk reduction options in this study, a recommendation has been made to implement MOP reductions and physical slab protection in HCAs on the RBP. No further risk reduction is considered possible without incurring costs grossly disproportionate to the incremental risk benefit.

It is therefore concluded that the recommended combination of MOP reduction and physical barrier protection has achieved reduction of risks to as low as reasonably practicable, in accordance with the requirements of AS 2885.1 and the Safety Management Study for the pipeline.

Appendix A

Pipeline Schematics

Current Configuration and ALARP Proposal



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ROMA BRISBANE PIPELINE
BRISBANE METRO AREA
SYSTEM SCHEMATIC

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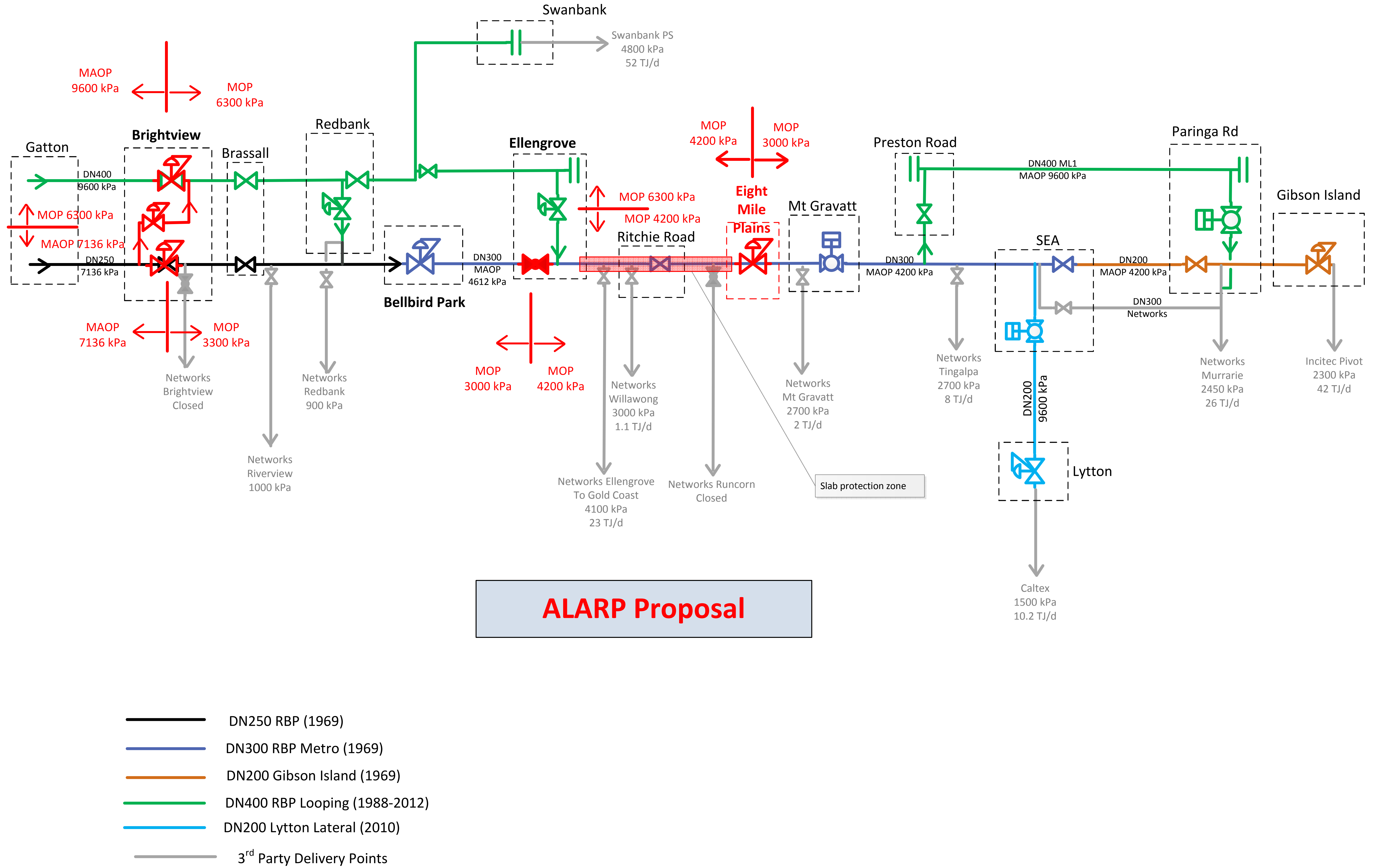

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ROMA BRISBANE PIPELINE
BRISBANE METRO AREA
SYSTEM SCHEMATIC

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Appendix B

HCA Segment Listing

Pipeline	KP Start	KP End	Location	LocClass Primary	LocClass Secondary	LocClass Notes	Pipe	CDL (mm)	Excavator size for 'No Rupture' fail	Total HCA Length	Non compliant @ 9.6MPa (current state)	Non compliant with Gatton Regulators	Non compliant with Brightview regulators	Difference between Gatton / Brightview
RBP DN250 Wallumbilla-Gatton	0.00	0.50	Wallumbilla	R1	HI	Various gas plants - consequence escala	4.78 WT X46	72.3	10 T	0.50	0.50	0.50	0.50	0.00
RBP DN250 Wallumbilla-Gatton	108.20	108.50	Condamine Compressor Station	R1	HI	Alinta compressor - consequence escala	4.78 WT X46	72.3	10 T	0.30	0.30	0.30	0.30	0.00
RBP DN250 Wallumbilla-Gatton	108.50	108.80	Condamine Compressor Station	R1	HI	Alinta compressor - consequence escala	4.78 WT X46	72.3	10 T	0.30	0.30	0.30	0.30	0.00
RBP DN250 Wallumbilla-Gatton	181.50	182.00	Wambo Feedlot	R1	I	Feedlot - personnel in measurement len	4.78 WT X46	72.3	10 T	0.50	0.50	0.50	0.50	0.00
RBP DN250 Wallumbilla-Gatton	183.70	184.80	Kogan North Facilities and Daandine PS	R1	HI	KN and Daandine gas / power plants - es	4.78 WT X46	72.3	10 T	1.10	1.10	1.10	1.10	0.00
RBP DN250 Wallumbilla-Gatton	218.90	219.70	Dalby Town	T1	-	Suburban development Branch Ck Rd	5.16WT X46	82.5	10 T	0.80	0.80	0.80	0.80	0.00
RBP DN250 Wallumbilla-Gatton	221.20	223.00	Dalby Industrial Outskirts	R1	I	Personnel in industrial worksites	5.16WT X46	82.5	10 T	1.80	1.80	1.80	1.80	0.00
RBP DN250 Wallumbilla-Gatton	223.90	224.90	Dalby Industrial Outskirts	R1	I	Personnel in industrial worksites	5.16WT X46	82.5	10 T	1.00	1.00	1.00	1.00	0.00
RBP DN250 Wallumbilla-Gatton	257.80	259.00	Jondaryan	T1	S		5.16WT X46	82.5	10 T	1.20	1.20	1.20	1.20	0.00
RBP DN250 Wallumbilla-Gatton	259.40	261.30	Jondaryan Tip/Golf	R2	I		5.16WT X46	82.5	10 T	1.90	1.90	1.90	1.90	0.00
RBP DN250 Wallumbilla-Gatton	268.70	269.50	Oakey Power	R1	HI		5.16WT X46	82.5	10 T	0.80	0.80	0.80	0.80	0.00
RBP DN250 Wallumbilla-Gatton	297.65	298.50	Toowoomba Outskirts	R2	I	Hermitage Road industry area	6.35WT X46	114.2	20 T	0.85	0.85	0.85	0.85	0.00
RBP DN250 Wallumbilla-Gatton	299.60	300.30	Mt Kynoch	T1	-		6.35WT X46	114.2	20 T	0.70	0.70	0.70	0.70	0.00
RBP DN250 Wallumbilla-Gatton	312.50	316.30	Postmans Ridge	R2	HI	Industry, explosives manufacturing	4.78 WT X46	72.3	10 T	3.80	3.80	3.80	3.80	0.00
RBP DN250 Gatton-Bellbird	335.00	336.10	Redbank Creek Road d/s Gatton CS	R2	I	Seedling nursery	5.16WT X46	82.5	10 T	1.10	1.10	0.00	1.10	-1.10
RBP DN250 Gatton-Bellbird	349.60	350.00	Brightview station western side	T1	-	Borderline T1 maybe R2	4.78 WT X46	72.3	10 T	0.40	0.40	0.00	0.40	-0.40
RBP DN250 Gatton-Bellbird	350.00	350.80	Brightview station east side	T1	-	Borderline T1 maybe R2	4.78 WT X46	72.3	10 T	0.80	0.80	0.00	0.00	0.00
RBP DN250 Gatton-Bellbird	353.90	355.60	Brightview Evans Rd	T1	-	Borderline T1 maybe R2	4.78 WT X46	72.3	10 T	1.70	1.70	0.00	0.00	0.00
RBP DN250 Gatton-Bellbird	375.40	378.60	Blacksoil	T1	-		5.16WT X46	82.5	10 T	3.20	3.20	0.00	0.00	0.00
RBP DN250 Gatton-Bellbird	381.50	383.00	Kholo Road - Francis St	T1	-		6.35WT X46	114.2	20 T	1.50	1.50	0.00	0.00	0.00
RBP DN250 Gatton-Bellbird	384.80	386.00	Coal Rd - Mt Crosby Rd	T1	-		6.35WT X46	114.2	20 T	1.20	1.20	0.00	0.00	0.00
RBP DN250 Gatton-Bellbird	386.00	386.80	Karalee shopping centre / tavern	T2	-		6.35WT X46	114.2	20 T	0.80	0.80	0.00	0.00	0.00
RBP DN250 Gatton-Bellbird	386.80	389.50	Karalee	T1	-		6.35WT X46	114.2	20 T	2.70	2.70	0.00	0.00	0.00
RBP DN250 Gatton-Bellbird	389.50	391.10	Dinmore meatworks	R2	I		6.35WT X46	114.2	20 T	1.60	1.60	0.00	0.00	0.00
RBP DN250 Gatton-Bellbird	391.70	393.20	Salvation Army land	T1	S	DN250 measurement length misses S re	6.35WT X46	114.2	20 T	0.00	0.00	0.00	0.00	0.00
RBP DN250 Gatton-Bellbird	393.20	394.20	Redbank	T1	-		6.35WT X46	114.2	20 T	1.00	1.00	0.00	0.00	0.00
RBP DN250 Gatton-Bellbird	395.00	395.20	Redbank	T1	-		6.35WT X46	114.2	20 T	0.20	0.20	0.00	0.00	0.00
RBP DN250 Gatton-Bellbird	395.20	396.10	Collingwood State School	T1	S	No slab in back of houses	6.35WT X46	114.2	20 T	0.90	0.90	0.00	0.00	0.00
RBP DN250 Gatton-Bellbird	396.10	397.40	Redbank Plains	T1	-		6.35WT X46	114.2	20 T	1.30	1.30	0.00	0.00	0.00
RBP DN250 Gatton-Bellbird	397.40	398.10	Kruger Primary School	T1	S		6.35WT X46	114.2	20 T	0.70	0.70	0.00	0.00	0.00
RBP DN250 Gatton-Bellbird	398.10	399.10	Bellbird Park	T1	-		6.35WT X46	114.2	20 T	1.00	1.00	0.00	0.00	0.00
RBP DN300 Bellbird - Ellengrove	399.10	400.60	Bellbird Park	T1	-		5.16WT X42	118.3	15 T	1.50	1.50	0.00	0.00	0.00
RBP DN300 Bellbird - Ellengrove	401.20	401.25	Parkwood Ave	T1			5.16WT X42	118.3	15 T	0.05	0.05	0.00	0.00	0.00
RBP DN300 Bellbird - Ellengrove	401.80	404.80	Meier Road to Centenary Mwy	T1	I	Assume 95% slabbing (skip bitumen etc)	5.16WT X42	118.3	15 T	3.00	2.85	0.00	0.00	0.00
RBP DN300 Ellengrove to Mt Gravatt	405.50	409.50	Johnson Rd to Blunder Rd	T1		Assume 95% slabbing (skip bitumen etc)	5.16WT X42	118.3	15 T	4.00	3.80	3.80	3.80	0.00
RBP DN300 Ellengrove to Mt Gravatt	411.20	411.80	Pallara State School	R2	S		5.16WT X42	118.3	15 T	0.60	0.60	0.60	0.60	0.00
RBP DN300 Ellengrove to Mt Gravatt	414.00	415.00	Paradise Rd to Ind Estate	T1			5.16WT X42	118.3	15 T	1.00	1.00	1.00	1.00	0.00
RBP DN300 Ellengrove to Mt Gravatt	415.30	416.50	Ind Estate to Beaudesert Rd	T1			5.16WT X42	118.3	15 T	1.20	1.20	1.20	1.20	0.00
RBP DN300 Ellengrove to Mt Gravatt	416.70	417.20	Jackson Rd to Hellawell Rd	T1			5.16WT X42	118.3	15 T	0.50	0.50	0.50	0.50	0.00
RBP DN300 Ellengrove to Mt Gravatt	417.30	418.00	Hellawell to Borella	T1		Could exclude private property	5.16WT X42	118.3	15 T	0.70	0.60	0.60	0.60	0.00
RBP DN300 Ellengrove to Mt Gravatt	418.00	418.60	Borella to Pinelands / Sunnybank School	T1	S		5.16WT X42	118.3	15 T	0.60	0.60	0.60	0.60	0.00
RBP DN300 Ellengrove to Mt Gravatt	418.95	419.45	Terowi to Beenleigh Rail	T1			5.16WT X42	118.3	15 T	0.50	0.50	0.50	0.50	0.00
RBP DN300 Ellengrove to Mt Gravatt	419.90	421.10	Sports fields to Kandanga St	T1			5.16WT X42	118.3	15 T	1.20	1.20	1.20	1.20	0.00
RBP DN300 Ellengrove to Mt Gravatt	421.30	421.36	Kandanga/Malbon crossings	T1			5.16WT X42	118.3	15 T	0.06	0.06	0.06	0.06	0.00
RBP DN300 Ellengrove to Mt Gravatt	421.55	421.95	Bronte Pl to Padstow Rd	T1			5.16WT X42	118.3	15 T	0.40	0.40	0.40	0.40	0.00
RBP DN300 Ellengrove to Mt Gravatt	422.00	422.90	Padstow Rd to Pacific Mwy	T2	S	90% - few roads etc	5.16WT X42	118.3	15 T	0.90	0.81	0.81	0.81	0.00
RBP DN300 Ellengrove to Mt Gravatt	423.00	424.15	Pacific Mwy to Delavan St	T1		Last section before potential regulator t	5.16WT X42	118.3	15 T	1.15	1.03	1.03	1.03	0.00
RBP DN300 Mt Gravatt to SEA	424.35	424.55	Reserve betw Cummin / Mannetto	T1			5.16WT X42	118.3	15 T	0.20	0.20	0.00	0.00	0.00
RBP DN300 Mt Gravatt to SEA	424.70	424.85	Merrick / village area	T1			5.16WT X42	118.3	15 T	0.15	0.15	0.00	0.00	0.00
RBP DN300 Mt Gravatt to SEA	424.95	425.50	Mt G / Cap Rd	T1		Note- Ham Rd is under bitumen	5.16WT X42	118.3	15 T	0.55	0.55	0.00	0.00	0.00
RBP DN300 Mt Gravatt to SEA	427.40	429.20	Wecker Rd to Pine Mtn Rd	T1		Utility corridor, 95%	5.16WT X42	118.3	15 T	1.80	1.71	0.00	0.00	0.00
RBP DN300 Mt Gravatt to SEA	429.82	430.26	N of golf course to Rainsby Ct	T1			5.16WT X42	118.3	15 T	0.44	0.42	0.00	0.00	0.00
RBP DN300 Mt Gravatt to SEA	430.32	431.15	Winstanley to Elcho	T1			5.16WT X42	118.3	15 T	0.83	0.79	0.00	0.00	0.00
RBP DN300 Mt Gravatt to SEA	431.20	432.90	Old Clev to Kate St / Ck crossing	T1			5.16WT X42	118.3	15 T	1.70	1.70	0.00	0.00	0.00
RBP DN300 Mt Gravatt to SEA	433.30	433.60	Start of T1 to Gateway Mwy	T1			5.16WT X42	118.3	15 T	0.30	0.30	0.00	0.00	0.00
RBP DN300 Mt Gravatt to SEA	433.70	437.90	Gateway to SEA	T1			5.16WT X42	118.3	15 T	4.20	3.99	0.00	0.00	0.00
RBP DN200 Gibson Is	437.85	440.00	SEA - Gibson Island	R2	I		4.78WT X42	152.2	30 T	2.15	2.15	0.00	0.00	0.00

Pipeline	KP Start	KP End	Location	LocClass Primary	LocClass Secondary	LocClass Notes	Pipe	CDL (mm)	Excavator size for 'No Rupture' fail	Total HCA Length	Non compliant @ 9.6MPa (current state)	Non compliant with Gatton Regulators	Non compliant with Brightview regulators	Difference between Gatton / Brightview
RBP DN400 Wallumbilla to Gatton	0.00	0.70	Wallumbilla	R1	HI	Various gas plants - consequence escala	6.4WT X60	79.3	10 T	0.70	0.70	0.70	0.70	0.00
RBP DN400 Wallumbilla to Gatton	108.00	108.50	Condamine Compressor Station	R1	HI	Alinta compressor - consequence escala	5.7WT X70	77.2	10 T	0.50	0.50	0.50	0.50	0.00
RBP DN400 Wallumbilla to Gatton	108.50	109.00	Condamine Compressor Station	R1	HI	Alinta compressor - consequence escala	6.4WT X60	79.3	10 T	0.50	0.50	0.50	0.50	0.00
RBP DN400 Wallumbilla to Gatton	181.30	182.20	Wambo Feedlot	R1	I	Feedlot - personnel in measurement len	5.7WT X70	77.2	10 T	0.90	0.90	0.90	0.90	0.00
RBP DN400 Wallumbilla to Gatton	183.50	185.00	Kogan North Facilities	R1	HI	KN and Daandine gas / power plants - es	5.7WT X70	77.2	10 T	1.50	1.50	1.50	1.50	0.00
RBP DN400 Wallumbilla to Gatton	218.40	220.60	Dalby Town	T1	-	Suburban development Branch Ck / San	7.7WT X60	116.30	15 T	2.20	2.20	2.20	2.20	0.00
RBP DN400 Wallumbilla to Gatton	221.00	223.20	Dalby Industrial Outskirts	R1	I	Personnel in industrial worksites	7.7WT X60	116.30	15 T	2.20	2.20	2.20	2.20	0.00
RBP DN400 Wallumbilla to Gatton	223.75	225.10	Dalby Industrial Outskirts	R1	I	Personnel in industrial worksites	7.7WT X60	116.30	15 T	1.35	1.35	1.35	1.35	0.00
RBP DN400 Wallumbilla to Gatton	245.70	246.80	Bowenville	T1	-	T1 size blocks only in DN400 meas lengt	7.7WT X60	116.30	15 T	1.10	1.10	1.10	1.10	0.00
RBP DN400 Wallumbilla to Gatton	257.50	259.50	Jondaryan	T1	S		7.9WT X60	122.1	30 T	2.00	2.00	2.00	2.00	0.00
RBP DN400 Wallumbilla to Gatton	259.20	261.50	Jondaryan Tip/Golf	R2	I		7.7WT X60	116.30	15 T	2.30	2.30	2.30	2.30	0.00
RBP DN400 Wallumbilla to Gatton	268.40	269.70	Oakey Power	R1	HI		6.4WT X60	79.3	10 T	1.30	1.30	1.30	1.30	0.00
RBP DN400 Wallumbilla to Gatton	297.50	298.70	Toowoomba Outskirts	T1	-		7.9WT X60	122.10	15 T	1.20	1.20	1.20	1.20	0.00
RBP DN400 Wallumbilla to Gatton	299.40	300.50	Mt Kynoch	T1	-		7.9WT X60	122.1	15 T	1.10	1.10	1.10	1.10	0.00
RBP DN400 Wallumbilla to Gatton	312.30	316.50	Postmans Ridge	R2	HI	Industry, explosives manufacturing	5.7WT X70	77.2	10 T	4.20	4.20	4.20	4.20	0.00
RBP DN400 Gatton to Moggill	334.90	336.30	Redbank Creek Road d/s Gatton CS	R2	I	Seedling nursery	7.7WT X60	116.30	15 T	1.40	1.40	1.40	1.40	0.00
RBP DN400 Gatton to Moggill	340.70	341.40	Lake Clarendon school	R1	S		7.7WT X60	116.3	15 T	0.70	0.70	0.70	0.70	0.00
RBP DN400 Gatton to Moggill	349.40	350.00	Brightview station western side	T1	-	Borderline T1 maybe R2	7.7WT X60	116.30	15 T	0.60	0.60	0.60	0.60	0.00
RBP DN400 Gatton to Moggill	350.00	350.90	Brightview station east side	T1	-	Borderline T1 maybe R2	7.7WT X60	116.30	15 T	0.90	0.90	0.90	0.00	0.90
RBP DN400 Gatton to Moggill	353.80	354.22	Brightview Evans Rd	T1	-	Borderline T1 maybe R2	5.7WT X70	77.2	10 T	0.42	0.42	0.42	0.42	0.00
RBP DN400 Gatton to Moggill	354.22	354.70	Brightview Evans Rd	T1	-	Borderline T1 maybe R2	6.8WT X70	110.0	15 T	0.48	0.48	0.48	0.00	0.48
RBP DN400 Gatton to Moggill	354.70	355.50	Brightview Evans Rd	T1	-	Borderline T1 maybe R2	8.1WT X70	152.0	30 T	0.80	0.80	0.00	0.00	0.00
RBP DN400 Gatton to Moggill	355.50	355.80	Brightview Evans Rd	T1	-	Borderline T1 maybe R2	5.7WT X70	77.2	10 T	0.30	0.30	0.30	0.30	0.00
RBP DN400 Gatton to Moggill	375.40	378.60	Blacksoil	T1	-		6.8WT X70	110.0	15 T	3.20	3.20	3.20	0.00	3.20
RBP DN400 Gatton to Moggill	381.50	383.00	Kholo Road - Francis St	T1	-		8.85WT X80	206.00	55 T	1.50	0.00	0.00	0.00	0.00
RBP DN400 Gatton to Moggill	384.80	385.80	Coal Rd - Mt Crosby Rd	T1	-		8.85WT X80	206.00	55 T	1.00	0.00	0.00	0.00	0.00
RBP DN400 Gatton to Moggill	385.80	387.00	Karalee shopping centre	T2	-		8.85WT X80	206.00	55 T	1.20	0.00	0.00	0.00	0.00
RBP DN400 Gatton to Moggill	387.00	389.50	Karalee	T1	-		8.85WT X80	206.00	55 T	2.50	0.00	0.00	0.00	0.00
RBP DN400 Gatton to Moggill	389.50	391.70	Dinmore meatworks	R2	I		8.85WT X80	206.00	55 T	2.20	0.00	0.00	0.00	0.00
RBP DN400 Gatton to Moggill	391.70	393.20	Salvation Army land	T1	S		8.85WT X80	206.00	55 T	1.50	0.00	0.00	0.00	0.00
RBP DN400 Swanbank Lateral	0.00	2.50	Moggill Ferry	T1	-	Borderline compliant - T1 constrn	8.1WT X70	152.0	30 T	2.50	2.50	0.00	0.00	0.00
RBP DN400 Swanbank Lateral	2.50	3.10	Collingwood State School	T1	S		9.7WT X70	208.0	55 T	0.60	0.00	0.00	0.00	0.00
RBP DN400 Swanbank Lateral	3.10	3.50	Collingwood Park	T1	-		9.7WT X70	208.0	55 T	0.40	0.00	0.00	0.00	0.00
RBP DN400 Swanbank Lateral	3.50	5.40	Collingwood Park shopping centre	T2	S	Borderline compliant - T1 constrn	8.1WT X70	152.0	30 T	1.90	1.90	0.00	0.00	0.00
RBP DN400 Swanbank Lateral	5.40	7.95	Collingwood Park - Redbank Plains	T1	-	Borderline compliant - T1 constrn	8.1WT X70	152.0	30 T	2.55	2.55	0.00	0.00	0.00
RBP DN400 Swanbank Lateral	7.95	8.80	Collingwood Park - Redbank Plains	T1	-		6.8WT X70	110.1	15 T	0.85	0.85	0.85	0.00	0.85
RBP DN400 Swanbank Lateral	8.80	10.70	Swanbank	R1	I	Slab only 1 ML from Swanbank	6.8WT X70	110.1	15 T	1.90	0.50	0.50	0.00	0.50
RBP DN400 Collingwood Ellengrove	0.00	2.10	Collingwood Park	T1	S	Borderline - flag	9.5WT X60	170.0	35 T	2.10	0.00	0.00	0.00	0.00
RBP DN400 Collingwood Ellengrove	2.10	5.40	Collingwood Park - Camira	T1	-	Borderline - flag	9.5WT X60	170.0	35 T	3.30	0.00	0.00	0.00	0.00
RBP DN400 Collingwood Ellengrove	5.40	6.50	Camira Primary School	T1	S	Borderline - flag	9.5WT X60	170.0	35 T	1.10	0.00	0.00	0.00	0.00
RBP DN400 Collingwood Ellengrove	6.50	9.30	Camira - Ellengrove	T1	I	Borderline - flag	9.5WT X60	170.0	35 T	2.80	0.00	0.00	0.00	0.00

Appendix C

Penetration Resistance and Energy Release Calculations

PIPELINE PENETRATION CALCULATIONS

AS 2885.1 - 2012 - Appendix M

RBP DN250 1969 4.78 mm

tw		4.78	mm				
MAOP		7.136	MPa				
CDL		72.3	mm				
Pipe Grade	API 5L	X46		σu	435	MPa	(lookup value)
OD, mm		273.1	mm				
Gas density, rho		0.562	kg/sm3				
GHV, MJ/sm3		37	MJ/sm3				

GP TOOTH

Excavator size (t)	L	W	Pipe Rp (kN)	Penetration? B=0.75	B=1	B=1.3
5	51	4	116.3	Resist	Resist	Resist
10	56	14	181.1	Resist	Resist	Resist
15	63	13	194.5	Resist	Resist	Resist
20	76	13	224.1	Resist	Resist	Resist
25	89	18	268.2	Resist	Resist	Resist
30	102	21	306.0	Resist	Resist	Resist
35	121	23	356.7	Resist	Resist	Resist
40	127	24	373.5	Resist	Resist	Resist
55	143	30	423.3	Resist	Resist	Resist

Failure Mode?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration

Hole Size (GP Teeth)?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration

Mass flow rate, kg/s

B=0.75	B=1	B=1.3
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak

Q, energy release rate, GJ/s

B=0.75	B=1	B=1.3
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00

TIGER TOOTH

Can a single point penetrate? | **Can a second point pe** | **Can a second point penetrate?**

Multiplier factor 1.75

Excavator size (t)	L	W	Pipe Rp (kN)	B=0.75	B=1	B=1.3	Equiv Rp	B=0.75	B=1	B=1.3
5	6	5	49.3	Resist	Resist	Resist	86.3	No Penetration	No Penetration	No Penetration
10	8	7	59.3	Resist	Penetrate	Penetrate	103.8	No Penetration	Single	Single
15	11	9	70.0	Penetrate	Penetrate	Penetrate	122.5	Single	Single	Both
20	13	10	76.2	Penetrate	Penetrate	Penetrate	133.3	Single	Both	Both
25	11	17	79.7	Penetrate	Penetrate	Penetrate	139.5	Single	Both	Both
30	12	20	84.1	Penetrate	Penetrate	Penetrate	147.1	Single	Both	Both
35	14	22	90.1	Penetrate	Penetrate	Penetrate	157.6	Both	Both	Both
40	16	25	96.5	Penetrate	Penetrate	Penetrate	168.8	Both	Both	Both
55	17	25	99.0	Penetrate	Penetrate	Penetrate	173.2	Both	Both	Both

Failure Mode?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture

Hole Size for Tiger Teeth?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	20	20
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture

Mass flow rate, kg/s

B=0.75	B=1	B=1.3
No Leak	No Leak	No Leak
No Leak	2.47	2.47
459.81	459.81	459.81
459.81	459.81	459.81
459.81	459.81	459.81
459.81	459.81	459.81
459.81	459.81	459.81
459.81	459.81	459.81
459.81	459.81	459.81

Q, energy release rate, GJ/s

B=0.75	B=1	B=1.3
0.00	0.00	0.00
0.00	0.16	0.16
30.27	30.27	30.27
30.27	30.27	30.27
30.27	30.27	30.27
30.27	30.27	30.27
30.27	30.27	30.27
30.27	30.27	30.27
30.27	30.27	30.27

PENETRATION TOOTH

Excavator size (t)	L	W	Pipe Rp (kN)	Penetration? GP Tooth B=0.75	B=1	B=1.3
5	6	5	49.3	Resist	Resist	Resist
10	8	7	59.3	Resist	Penetrate	Penetrate
15	11	9	70.0	Penetrate	Penetrate	Penetrate
20	13	10	76.2	Penetrate	Penetrate	Penetrate
25	11	17	79.7	Penetrate	Penetrate	Penetrate
30	12	20	84.1	Penetrate	Penetrate	Penetrate
35	14	22	90.1	Penetrate	Penetrate	Penetrate
40	16	25	96.5	Penetrate	Penetrate	Penetrate
55	17	25	99.0	Penetrate	Penetrate	Penetrate

Failure Mode?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture

Hole Size (Penetration Tooth)

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	45	45
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture

Mass flow rate, kg/s

B=0.75	B=1	B=1.3
No Leak	No Leak	No Leak
No Leak	12.48	12.48
459.81	459.81	459.81
459.81	459.81	459.81
459.81	459.81	459.81
459.81	459.81	459.81
459.81	459.81	459.81
459.81	459.81	459.81
459.81	459.81	459.81

Q, energy release rate, GJ/s

B=0.75	B=1	B=1.3
0.00	0.00	0.00
0.00	0.82	0.82
30.27	30.27	30.27
30.27	30.27	30.27
30.27	30.27	30.27
30.27	30.27	30.27
30.27	30.27	30.27
30.27	30.27	30.27
30.27	30.27	30.27

PIPELINE PENETRATION CALCULATIONS

AS 2885.1 - 2012 - Appendix M

RBP DN250 1969 5.16 mm

tw		5.16	mm			
MAOP		7.136	MPa			
CDL		82.5	mm			
Pipe Grade	API 5L	X46		σu	435 MPa	(lookup value)
OD, mm		273.1	mm			
Gas density, rho		0.562	kg/sm3			
GHV, MJ/sm3		37	MJ/sm3			

GP TOOTH

Excavator size (t)	L	W	Pipe Rp (kN)	Penetration? B=0.75	B=1	B=1.3
5	51	4	125.5	Resist	Resist	Resist
10	56	14	195.5	Resist	Resist	Resist
15	63	13	209.9	Resist	Resist	Resist
20	76	13	241.9	Resist	Resist	Resist
25	89	18	289.5	Resist	Resist	Resist
30	102	21	330.3	Resist	Resist	Resist
35	121	23	385.1	Resist	Resist	Resist
40	127	24	403.2	Resist	Resist	Resist
55	143	30	457.0	Resist	Resist	Resist

Excavator size (t)	Failure Mode? B=0.75	B=1	B=1.3	Hole Size (GP Teeth)? B=0.75	B=1	B=1.3
5	No Penetration	No Penetration	No Penetration	No Penetration	No Penetration	No Penetration
10	No Penetration	No Penetration	No Penetration	No Penetration	No Penetration	No Penetration
15	No Penetration	No Penetration	No Penetration	No Penetration	No Penetration	No Penetration
20	No Penetration	No Penetration	No Penetration	No Penetration	No Penetration	No Penetration
25	No Penetration	No Penetration	No Penetration	No Penetration	No Penetration	No Penetration
30	No Penetration	No Penetration	No Penetration	No Penetration	No Penetration	No Penetration
35	No Penetration	No Penetration	No Penetration	No Penetration	No Penetration	No Penetration
40	No Penetration	No Penetration	No Penetration	No Penetration	No Penetration	No Penetration
55	No Penetration	No Penetration	No Penetration	No Penetration	No Penetration	No Penetration

Excavator size (t)	Mass flow rate, kg/s B=0.75	B=1	B=1.3	Q, energy release rate, GJ/s B=0.75	B=1	B=1.3
5	No Leak	No Leak	No Leak	0.00	0.00	0.00
10	No Leak	No Leak	No Leak	0.00	0.00	0.00
15	No Leak	No Leak	No Leak	0.00	0.00	0.00
20	No Leak	No Leak	No Leak	0.00	0.00	0.00
25	No Leak	No Leak	No Leak	0.00	0.00	0.00
30	No Leak	No Leak	No Leak	0.00	0.00	0.00
35	No Leak	No Leak	No Leak	0.00	0.00	0.00
40	No Leak	No Leak	No Leak	0.00	0.00	0.00
55	No Leak	No Leak	No Leak	0.00	0.00	0.00

TIGER TOOTH

Can a second point p Can a second point penetrate?

Multiplier factor 1.75

Excavator size (t)	L	W	Pipe Rp (kN)	Can a single point penetrate? B=0.75	B=1	B=1.3	Equiv Rp	Can a second point penetrate? B=0.75	B=1	B=1.3
5	6	5	53.2	Resist	Resist	Resist	93.2	No Penetration	No Penetration	No Penetration
10	8	7	64.1	Resist	Penetrate	Penetrate	112.1	No Penetration	Single	Single
15	11	9	75.6	Penetrate	Penetrate	Penetrate	132.3	Single	Single	Both
20	13	10	82.2	Penetrate	Penetrate	Penetrate	143.9	Single	Single	Both
25	11	17	86.0	Penetrate	Penetrate	Penetrate	150.6	Single	Both	Both
30	12	20	90.7	Penetrate	Penetrate	Penetrate	158.8	Single	Both	Both
35	14	22	97.2	Penetrate	Penetrate	Penetrate	170.1	Single	Both	Both
40	16	25	104.1	Penetrate	Penetrate	Penetrate	182.2	Single	Both	Both
55	17	25	106.8	Penetrate	Penetrate	Penetrate	187.0	Both	Both	Both

Excavator size (t)	Failure Mode? B=0.75	B=1	B=1.3	Hole Size for Tiger Teeth? B=0.75	B=1	B=1.3
5	No Penetration	No Penetration	No Penetration	No Penetration	No Penetration	No Penetration
10	No Penetration	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)	No Penetration	20	20
15	Rupture	Rupture	Rupture	Rupture	Rupture	Rupture
20	Rupture	Rupture	Rupture	Rupture	Rupture	Rupture
25	Rupture	Rupture	Rupture	Rupture	Rupture	Rupture
30	Rupture	Rupture	Rupture	Rupture	Rupture	Rupture
35	Rupture	Rupture	Rupture	Rupture	Rupture	Rupture
40	Rupture	Rupture	Rupture	Rupture	Rupture	Rupture
55	Rupture	Rupture	Rupture	Rupture	Rupture	Rupture

Excavator size (t)	Mass flow rate, kg/s B=0.75	B=1	B=1.3	Q, energy release rate, GJ/s B=0.75	B=1	B=1.3
5	No Leak	No Leak	No Leak	0.00	0.00	0.00
10	No Leak	2.47	2.47	0.00	0.16	0.16
15	459.81	459.81	459.81	30.27	30.27	30.27
20	459.81	459.81	459.81	30.27	30.27	30.27
25	459.81	459.81	459.81	30.27	30.27	30.27
30	459.81	459.81	459.81	30.27	30.27	30.27
35	459.81	459.81	459.81	30.27	30.27	30.27
40	459.81	459.81	459.81	30.27	30.27	30.27
55	459.81	459.81	459.81	30.27	30.27	30.27

PENETRATION TOOTH

Excavator size (t)	L	W	Pipe Rp (kN)	Penetration? GP Tooth B=0.75	B=1	B=1.3
5	6	5	53.2	Resist	Resist	Resist
10	8	7	64.1	Resist	Penetrate	Penetrate
15	11	9	75.6	Penetrate	Penetrate	Penetrate
20	13	10	82.2	Penetrate	Penetrate	Penetrate
25	11	17	86.0	Penetrate	Penetrate	Penetrate
30	12	20	90.7	Penetrate	Penetrate	Penetrate
35	14	22	97.2	Penetrate	Penetrate	Penetrate
40	16	25	104.1	Penetrate	Penetrate	Penetrate
55	17	25	106.8	Penetrate	Penetrate	Penetrate

Excavator size (t)	Failure Mode? B=0.75	B=1	B=1.3	Hole Size (Penetration Tooth) B=0.75	B=1	B=1.3
5	No Penetration	No Penetration	No Penetration	No Penetration	No Penetration	No Penetration
10	No Penetration	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)	No Penetration	45	45
15	Rupture	Rupture	Rupture	Rupture	Rupture	Rupture
20	Rupture	Rupture	Rupture	Rupture	Rupture	Rupture
25	Rupture	Rupture	Rupture	Rupture	Rupture	Rupture
30	Rupture	Rupture	Rupture	Rupture	Rupture	Rupture
35	Rupture	Rupture	Rupture	Rupture	Rupture	Rupture
40	Rupture	Rupture	Rupture	Rupture	Rupture	Rupture
55	Rupture	Rupture	Rupture	Rupture	Rupture	Rupture

Excavator size (t)	Mass flow rate, kg/s B=0.75	B=1	B=1.3	Q, energy release rate, GJ/s B=0.75	B=1	B=1.3
5	No Leak	No Leak	No Leak	0.00	0.00	0.00
10	No Leak	12.48	12.48	0.00	0.82	0.82
15	459.81	459.81	459.81	30.27	30.27	30.27
20	459.81	459.81	459.81	30.27	30.27	30.27
25	459.81	459.81	459.81	30.27	30.27	30.27
30	459.81	459.81	459.81	30.27	30.27	30.27
35	459.81	459.81	459.81	30.27	30.27	30.27
40	459.81	459.81	459.81	30.27	30.27	30.27
55	459.81	459.81	459.81	30.27	30.27	30.27

PIPELINE PENETRATION CALCULATIONS

AS 2885.1 - 2012 - Appendix M

RBP DN250 1969 6.35 mm

tw		6.35	mm				
MAOP		7.136	MPa				
CDL		114.2	mm				
Pipe Grade	API 5L	X46		σu	435	MPa	(lookup value)
OD, mm		273.1	mm				
Gas density, rho		0.562	kg/sm3				
GHV, MJ/sm3		37	MJ/sm3				

GP TOOTH

Excavator size (t)	L	W	Pipe Rp (kN)	Penetration? B=0.75	B=1	B=1.3
5	51	4	154.4	Resist	Resist	Resist
10	56	14	240.5	Resist	Resist	Resist
15	63	13	258.4	Resist	Resist	Resist
20	76	13	297.7	Resist	Resist	Resist
25	89	18	356.3	Resist	Resist	Resist
30	102	21	406.5	Resist	Resist	Resist
35	121	23	473.9	Resist	Resist	Resist
40	127	24	496.2	Resist	Resist	Resist
55	143	30	562.4	Resist	Resist	Resist

Failure Mode?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration

Hole Size (GP Teeth)?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration

Mass flow rate, kg/s

B=0.75	B=1	B=1.3
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak

Q, energy release rate, GJ/s

B=0.75	B=1	B=1.3
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00

TIGER TOOTH

Can a single point penetrate?

Excavator size (t)	L	W	Pipe Rp (kN)	B=0.75	B=1	B=1.3
5	6	5	65.5	Resist	Resist	Resist
10	8	7	78.8	Resist	Resist	Penetrate
15	11	9	93.0	Resist	Penetrate	Penetrate
20	13	10	101.2	Resist	Penetrate	Penetrate
25	11	17	105.9	Penetrate	Penetrate	Penetrate
30	12	20	111.7	Penetrate	Penetrate	Penetrate
35	14	22	119.6	Penetrate	Penetrate	Penetrate
40	16	25	128.1	Penetrate	Penetrate	Penetrate
55	17	25	131.5	Penetrate	Penetrate	Penetrate

Can a second point pe Can a second point penetrate?

Multiplier factor 1.75

Equiv Rp	B=0.75	B=1	B=1.3
114.7	No Penetration	No Penetration	No Penetration
137.9	No Penetration	No Penetration	Single
162.8	No Penetration	Single	Single
177.1	No Penetration	Single	Single
185.3	Single	Single	Both
195.4	Single	Single	Both
209.4	Single	Both	Both
224.2	Single	Both	Both
230.1	Single	Both	Both

Failure Mode?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	Leak
No Penetration	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
No Penetration	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
Leak (Non HCA Compliant)	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
Leak (Non HCA Compliant)	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture

Hole Size for Tiger Teeth?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	20
No Penetration	20	20
No Penetration	25	25
25	25	85
30	30	95
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture

Mass flow rate, kg/s

B=0.75	B=1	B=1.3
No Leak	No Leak	No Leak
No Leak	No Leak	2.47
No Leak	2.47	2.47
No Leak	3.85	3.85
3.85	3.85	44.54
5.55	5.55	55.64
459.81	459.81	459.81
459.81	459.81	459.81
459.81	459.81	459.81

Q, energy release rate, GJ/s

B=0.75	B=1	B=1.3
0.00	0.00	0.00
0.00	0.00	0.16
0.00	0.16	0.16
0.00	0.25	0.25
0.25	0.25	2.93
0.37	0.37	3.66
30.27	30.27	30.27
30.27	30.27	30.27
30.27	30.27	30.27

PENETRATION TOOTH

Penetration?

Excavator size (t)	L	W	Pipe Rp (kN)	GP Tooth B=0.75	B=1	B=1.3
5	6	5	65.5	Resist	Resist	Resist
10	8	7	78.8	Resist	Resist	Penetrate
15	11	9	93.0	Resist	Penetrate	Penetrate
20	13	10	101.2	Resist	Penetrate	Penetrate
25	11	17	105.9	Penetrate	Penetrate	Penetrate
30	12	20	111.7	Penetrate	Penetrate	Penetrate
35	14	22	119.6	Penetrate	Penetrate	Penetrate
40	16	25	128.1	Penetrate	Penetrate	Penetrate
55	17	25	131.5	Penetrate	Penetrate	Penetrate

Failure Mode?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	Leak
No Penetration	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
No Penetration	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
Leak (Non HCA Compliant)	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
Leak (Non HCA Compliant)	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture

Hole Size (Penetration Tooth)

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	45
No Penetration	55	55
No Penetration	60	60
65	65	65
70	70	70
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture

Mass flow rate, kg/s

B=0.75	B=1	B=1.3
No Leak	No Leak	No Leak
No Leak	No Leak	12.48
No Leak	18.65	18.65
No Leak	22.19	22.19
26.05	26.05	26.05
30.21	30.21	30.21
459.81	459.81	459.81
459.81	459.81	459.81
459.81	459.81	459.81

Q, energy release rate, GJ/s

B=0.75	B=1	B=1.3
0.00	0.00	0.00
0.00	0.00	0.82
0.00	1.23	1.23
0.00	1.46	1.46
1.71	1.71	1.71
1.99	1.99	1.99
30.27	30.27	30.27
30.27	30.27	30.27
30.27	30.27	30.27

PIPELINE PENETRATION CALCULATIONS

AS 2885.1 - 2012 - Appendix M

RBP DN300 Metro 1969

tw		5.16	mm			
MAOP		4.612	Mpa			
CDL		118	mm			
Pipe Grade	API 5L	X42		σu	415 MPa	(lookup value)
OD, mm		323.9	mm			
Gas density, rho		0.562	kg/sm3			
GHV, MJ/sm3		37	MJ/sm3			

GP TOOTH

Penetration?

Excavator size (t)	GP Tooth L	W	Pipe Rp (kN)	B=0.75	B=1	B=1.3
5	51	4	122.5	Resist	Resist	Resist
10	56	14	190.8	Resist	Resist	Resist
15	63	13	205.0	Resist	Resist	Resist
20	76	13	236.2	Resist	Resist	Resist
25	89	18	282.7	Resist	Resist	Resist
30	102	21	322.5	Resist	Resist	Resist
35	121	23	376.0	Resist	Resist	Resist
40	127	24	393.7	Resist	Resist	Resist
55	143	30	446.2	Resist	Resist	Resist

Failure Mode?

Excavator size (t)	B=0.75	B=1	B=1.3
5	No Penetration	No Penetration	No Penetration
10	No Penetration	No Penetration	No Penetration
15	No Penetration	No Penetration	No Penetration
20	No Penetration	No Penetration	No Penetration
25	No Penetration	No Penetration	No Penetration
30	No Penetration	No Penetration	No Penetration
35	No Penetration	No Penetration	No Penetration
40	No Penetration	No Penetration	No Penetration
55	No Penetration	No Penetration	No Penetration

Hole Size (GP Teeth)?

Excavator size (t)	B=0.75	B=1	B=1.3
5	No Penetration	No Penetration	No Penetration
10	No Penetration	No Penetration	No Penetration
15	No Penetration	No Penetration	No Penetration
20	No Penetration	No Penetration	No Penetration
25	No Penetration	No Penetration	No Penetration
30	No Penetration	No Penetration	No Penetration
35	No Penetration	No Penetration	No Penetration
40	No Penetration	No Penetration	No Penetration
55	No Penetration	No Penetration	No Penetration

Mass flow rate, kg/s

Excavator size (t)	B=0.75	B=1	B=1.3
5	No Leak	No Leak	No Leak
10	No Leak	No Leak	No Leak
15	No Leak	No Leak	No Leak
20	No Leak	No Leak	No Leak
25	No Leak	No Leak	No Leak
30	No Leak	No Leak	No Leak
35	No Leak	No Leak	No Leak
40	No Leak	No Leak	No Leak
55	No Leak	No Leak	No Leak

Q, energy release rate, GJ/s

Excavator size (t)	B=0.75	B=1	B=1.3
5	0.00	0.00	0.00
10	0.00	0.00	0.00
15	0.00	0.00	0.00
20	0.00	0.00	0.00
25	0.00	0.00	0.00
30	0.00	0.00	0.00
35	0.00	0.00	0.00
40	0.00	0.00	0.00
55	0.00	0.00	0.00

TIGER TOOTH

Can a single point penetrate?

Excavator size (t)	Tiger Tooth L	W	Pipe Rp (kN)	B=0.75	B=1	B=1.3
5	6	5	52.0	Resist	Resist	Resist
10	8	7	62.5	Resist	Penetrate	Penetrate
15	11	9	73.8	Penetrate	Penetrate	Penetrate
20	13	10	80.3	Penetrate	Penetrate	Penetrate
25	11	17	84.0	Penetrate	Penetrate	Penetrate
30	12	20	88.6	Penetrate	Penetrate	Penetrate
35	14	22	94.9	Penetrate	Penetrate	Penetrate
40	16	25	101.7	Penetrate	Penetrate	Penetrate
55	17	25	104.3	Penetrate	Penetrate	Penetrate

Can a second point p **Can a second point penetrate?**

Multiplier factor 1.75

Excavator size (t)	Equiv Rp	B=0.75	B=1	B=1.3
5	91.0	No Penetration	No Penetration	No Penetration
10	109.4	No Penetration	Single	Single
15	129.1	Single	Single	Both
20	140.5	Single	Single	Both
25	147.0	Single	Both	Both
30	155.0	Single	Both	Both
35	166.1	Single	Both	Both
40	177.9	Single	Both	Both
55	182.5	Both	Both	Both

Failure Mode?

Excavator size (t)	B=0.75	B=1	B=1.3
5	No Penetration	No Penetration	No Penetration
10	No Penetration	Leak	Leak
15	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
20	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
25	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
30	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
35	Rupture	Rupture	Rupture
40	Rupture	Rupture	Rupture
55	Rupture	Rupture	Rupture

Hole Size for Tiger Teeth?

Excavator size (t)	B=0.75	B=1	B=1.3
5	No Penetration	No Penetration	No Penetration
10	No Penetration	20	20
15	20	20	70
20	25	25	80
25	25	85	85
30	30	95	95
35	Rupture	Rupture	Rupture
40	Rupture	Rupture	Rupture
55	Rupture	Rupture	Rupture

Mass flow rate, kg/s

Excavator size (t)	B=0.75	B=1	B=1.3
5	No Leak	No Leak	No Leak
10	No Leak	1.59	1.59
15	1.59	1.59	19.52
20	2.49	2.49	25.50
25	2.49	28.79	28.79
30	3.59	35.96	35.96
35	418.02	418.02	418.02
40	418.02	418.02	418.02
55	418.02	418.02	418.02

Q, energy release rate, GJ/s

Excavator size (t)	B=0.75	B=1	B=1.3
5	0.00	0.00	0.00
10	0.00	0.10	0.10
15	0.10	0.10	1.29
20	0.16	0.16	1.68
25	0.16	1.90	1.90
30	0.24	2.37	2.37
35	27.52	27.52	27.52
40	27.52	27.52	27.52
55	27.52	27.52	27.52

PENETRATION TOOTH

Penetration?

Excavator size (t)	GP Tooth L	W	Pipe Rp (kN)	B=0.75	B=1	B=1.3
5	6	5	52.0	Resist	Resist	Resist
10	8	7	62.5	Resist	Penetrate	Penetrate
15	11	9	73.8	Penetrate	Penetrate	Penetrate
20	13	10	80.3	Penetrate	Penetrate	Penetrate
25	11	17	84.0	Penetrate	Penetrate	Penetrate
30	12	20	88.6	Penetrate	Penetrate	Penetrate
35	14	22	94.9	Penetrate	Penetrate	Penetrate
40	16	25	101.7	Penetrate	Penetrate	Penetrate
55	17	25	104.3	Penetrate	Penetrate	Penetrate

Failure Mode?

Excavator size (t)	B=0.75	B=1	B=1.3
5	No Penetration	No Penetration	No Penetration
10	No Penetration	Leak	Leak
15	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
20	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
25	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
30	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
35	Rupture	Rupture	Rupture
40	Rupture	Rupture	Rupture
55	Rupture	Rupture	Rupture

Hole Size (Penetration Tooth)

Excavator size (t)	B=0.75	B=1	B=1.3
5	No Penetration	No Penetration	No Penetration
10	No Penetration	45	45
15	55	55	55
20	60	60	60
25	65	65	65
30	70	70	70
35	Rupture	Rupture	Rupture
40	Rupture	Rupture	Rupture
55	Rupture	Rupture	Rupture

Mass flow rate, kg/s

Excavator size (t)	B=0.75	B=1	B=1.3
5	No Leak	No Leak	No Leak
10	No Leak	8.07	8.07
15	12.05	12.05	12.05
20	14.34	14.34	14.34
25	16.83	16.83	16.83
30	19.52	19.52	19.52
35	418.02	418.02	418.02
40	418.02	418.02	418.02
55	418.02	418.02	418.02

Q, energy release rate, GJ/s

Excavator size (t)	B=0.75	B=1	B=1.3
5	0.00	0.00	0.00
10	0.00	0.53	0.53
15	0.79	0.79	0.79
20	0.94	0.94	0.94
25	1.11	1.11	1.11
30	1.29	1.29	1.29
35	27.52	27.52	27.52
40	27.52	27.52	27.52
55	27.52	27.52	27.52

PIPELINE PENETRATION CALCULATIONS

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RBP DN400 5.7 mm X70

tw		5.7	mm			
MAOP		9.6	MPa			
CDL		77.2	mm			
Pipe Grade	API 5L	X70		σu	570 MPa	(lookup value)
OD, mm		406.4	mm			
Gas density, rho		0.562	kg/sm3			
GHV, MJ/sm3		37	MJ/sm3			

GP TOOTH

Penetration?

Excavator size (t)	GP Tooth L	W	Pipe Rp (kN)	B=0.75	B=1	B=1.3
5	51	4	160.8	Resist	Resist	Resist
10	56	14	250.4	Resist	Resist	Resist
15	63	13	269.0	Resist	Resist	Resist
20	76	13	309.9	Resist	Resist	Resist
25	89	18	370.9	Resist	Resist	Resist
30	102	21	423.2	Resist	Resist	Resist
35	121	23	493.4	Resist	Resist	Resist
40	127	24	516.6	Resist	Resist	Resist
55	143	30	585.5	Resist	Resist	Resist

Failure Mode?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration

Hole Size (GP Teeth)?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration

Mass flow rate, kg/s

B=0.75	B=1	B=1.3
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak

Q, energy release rate, GJ/s

B=0.75	B=1	B=1.3
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00

TIGER TOOTH

Can a single point penetrate?

Excavator size (t)	Tiger Tooth L	W	Pipe Rp (kN)	B=0.75	B=1	B=1.3
5	6	5	68.2	Resist	Resist	Resist
10	8	7	82.1	Resist	Resist	Penetrate
15	11	9	96.8	Resist	Penetrate	Penetrate
20	13	10	105.3	Resist	Penetrate	Penetrate
25	11	17	110.2	Penetrate	Penetrate	Penetrate
30	12	20	116.3	Penetrate	Penetrate	Penetrate
35	14	22	124.6	Penetrate	Penetrate	Penetrate
40	16	25	133.4	Penetrate	Penetrate	Penetrate
55	17	25	136.9	Penetrate	Penetrate	Penetrate

Can a second point pe Can a second point penetrate?

Multiplier factor 1.75

Equiv Rp	B=0.75	B=1	B=1.3
119.4	No Penetration	No Penetration	No Penetration
143.6	No Penetration	No Penetration	Single
169.4	No Penetration	Single	Single
184.4	No Penetration	Single	Single
192.9	Single	Single	Both
203.5	Single	Single	Both
218.0	Single	Single	Both
233.4	Single	Both	Both
239.5	Single	Both	Both

Failure Mode?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	Leak (Non HCA Compliant)
No Penetration	Rupture	Rupture
No Penetration	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture

Hole Size for Tiger Teeth?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	20
No Penetration	Rupture	Rupture
No Penetration	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture

Mass flow rate, kg/s

B=0.75	B=1	B=1.3
No Leak	No Leak	No Leak
No Leak	No Leak	3.32
No Leak	1369.81	1369.81
No Leak	1369.81	1369.81
1369.81	1369.81	1369.81
1369.81	1369.81	1369.81
1369.81	1369.81	1369.81
1369.81	1369.81	1369.81
1369.81	1369.81	1369.81

Q, energy release rate, GJ/s

B=0.75	B=1	B=1.3
0.00	0.00	0.00
0.00	0.00	0.22
0.00	90.18	90.18
0.00	90.18	90.18
90.18	90.18	90.18
90.18	90.18	90.18
90.18	90.18	90.18
90.18	90.18	90.18
90.18	90.18	90.18

PENETRATION TOOTH

Penetration?

Excavator size (t)	GP Tooth L	W	Pipe Rp (kN)	B=0.75	B=1	B=1.3
5	6	5	68.2	Resist	Resist	Resist
10	8	7	82.1	Resist	Resist	Penetrate
15	11	9	96.8	Resist	Penetrate	Penetrate
20	13	10	105.3	Resist	Penetrate	Penetrate
25	11	17	110.2	Penetrate	Penetrate	Penetrate
30	12	20	116.3	Penetrate	Penetrate	Penetrate
35	14	22	124.6	Penetrate	Penetrate	Penetrate
40	16	25	133.4	Penetrate	Penetrate	Penetrate
55	17	25	136.9	Penetrate	Penetrate	Penetrate

Failure Mode?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	Leak (Non HCA Compliant)
No Penetration	Rupture	Rupture
No Penetration	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture

Hole Size (Penetration Tooth)

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	45
No Penetration	Rupture	Rupture
No Penetration	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture

Mass flow rate, kg/s

B=0.75	B=1	B=1.3
No Leak	No Leak	No Leak
No Leak	No Leak	16.79
No Leak	1369.81	1369.81
No Leak	1369.81	1369.81
1369.81	1369.81	1369.81
1369.81	1369.81	1369.81
1369.81	1369.81	1369.81
1369.81	1369.81	1369.81
1369.81	1369.81	1369.81

Q, energy release rate, GJ/s

B=0.75	B=1	B=1.3
0.00	0.00	0.00
0.00	0.00	1.11
0.00	90.18	90.18
0.00	90.18	90.18
90.18	90.18	90.18
90.18	90.18	90.18
90.18	90.18	90.18
90.18	90.18	90.18
90.18	90.18	90.18

PIPELINE PENETRATION CALCULATIONS

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RBP DN400 6.8 mm X70

tw		6.8	mm				
MAOP		9.6	MPa				
CDL		110	mm				
Pipe Grade	API 5L	X70		σu	570	MPa	(lookup value)
OD, mm		406.4	mm				
Gas density, rho		0.562	kg/sm3				
GHV, MJ/sm3		37	MJ/sm3				

GP TOOTH

Penetration?

Excavator size (t)	GP Tooth					
	L	W	Pipe Rp (kN)	B=0.75	B=1	B=1.3
5	51	4	191.8	Resist	Resist	Resist
10	56	14	298.7	Resist	Resist	Resist
15	63	13	320.9	Resist	Resist	Resist
20	76	13	369.7	Resist	Resist	Resist
25	89	18	442.5	Resist	Resist	Resist
30	102	21	504.8	Resist	Resist	Resist
35	121	23	588.6	Resist	Resist	Resist
40	127	24	616.3	Resist	Resist	Resist
55	143	30	698.5	Resist	Resist	Resist

Failure Mode?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration

Hole Size (GP Teeth)?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration

Mass flow rate, kg/s

B=0.75	B=1	B=1.3
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak

Q, energy release rate, GJ/s

B=0.75	B=1	B=1.3
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00

TIGER TOOTH

Can a single point penetrate?

Excavator size (t)	Tiger Tooth					
	L	W	Pipe Rp (kN)	B=0.75	B=1	B=1.3
5	6	5	81.4	Resist	Resist	Resist
10	8	7	97.9	Resist	Resist	Resist
15	11	9	115.5	Resist	Resist	Penetrate
20	13	10	125.7	Resist	Penetrate	Penetrate
25	11	17	131.5	Resist	Penetrate	Penetrate
30	12	20	138.7	Penetrate	Penetrate	Penetrate
35	14	22	148.6	Penetrate	Penetrate	Penetrate
40	16	25	159.1	Penetrate	Penetrate	Penetrate
55	17	25	163.3	Penetrate	Penetrate	Penetrate

Can a second point p **Can a second point penetrate?**

Multiplier factor 1.75

Equiv Rp	B=0.75	B=1	B=1.3
142.4	No Penetration	No Penetration	No Penetration
171.3	No Penetration	No Penetration	No Penetration
202.1	No Penetration	No Penetration	Single
219.9	No Penetration	Single	Single
230.1	No Penetration	Single	Single
242.7	Single	Single	Both
260.0	Single	Single	Both
278.5	Single	Single	Both
285.7	Single	Both	Both

Failure Mode?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	Leak (Non HCA Compliant)
No Penetration	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
No Penetration	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture

Hole Size for Tiger Teeth?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	20
No Penetration	25	25
No Penetration	25	25
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture

Mass flow rate, kg/s

B=0.75	B=1	B=1.3
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	3.32
No Leak	5.18	5.18
No Leak	5.18	5.18
1369.81	1369.81	1369.81
1369.81	1369.81	1369.81
1369.81	1369.81	1369.81
1369.81	1369.81	1369.81

Q, energy release rate, GJ/s

B=0.75	B=1	B=1.3
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.22
0.00	0.34	0.34
0.00	0.34	0.34
90.18	90.18	90.18
90.18	90.18	90.18
90.18	90.18	90.18
90.18	90.18	90.18

PENETRATION TOOTH

Penetration?

Excavator size (t)	GP Tooth					
	L	W	Pipe Rp (kN)	B=0.75	B=1	B=1.3
5	6	5	81.4	Resist	Resist	Resist
10	8	7	97.9	Resist	Resist	Resist
15	11	9	115.5	Resist	Resist	Penetrate
20	13	10	125.7	Resist	Penetrate	Penetrate
25	11	17	131.5	Resist	Penetrate	Penetrate
30	12	20	138.7	Penetrate	Penetrate	Penetrate
35	14	22	148.6	Penetrate	Penetrate	Penetrate
40	16	25	159.1	Penetrate	Penetrate	Penetrate
55	17	25	163.3	Penetrate	Penetrate	Penetrate

Failure Mode?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	Leak (Non HCA Compliant)
No Penetration	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
No Penetration	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture

Hole Size (Penetration Tooth)

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	55
No Penetration	60	60
No Penetration	65	65
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture
Rupture	Rupture	Rupture

Mass flow rate, kg/s

B=0.75	B=1	B=1.3
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	25.09
No Leak	29.86	29.86
No Leak	35.04	35.04
1369.81	1369.81	1369.81
1369.81	1369.81	1369.81
1369.81	1369.81	1369.81
1369.81	1369.81	1369.81

Q, energy release rate, GJ/s

B=0.75	B=1	B=1.3
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	1.65
0.00	1.97	1.97
0.00	2.31	2.31
90.18	90.18	90.18
90.18	90.18	90.18
90.18	90.18	90.18
90.18	90.18	90.18

PIPELINE PENETRATION CALCULATIONS

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RBP DN400 7.7 mm X70

tw		7.7	mm				
MAOP		9.6	MPa				
CDL		116.3	mm				
Pipe Grade	API 5L	X70		σu	570	MPa	(lookup value)
OD, mm		406.4	mm				
Gas density, rho		0.562	kg/sm3				
GHV, MJ/sm3		37	MJ/sm3				

GP TOOTH

Penetration?

Excavator size (t)	GP Tooth L	W	Pipe Rp (kN)	B=0.75	B=1	B=1.3
5	51	4	217.2	Resist	Resist	Resist
10	56	14	338.3	Resist	Resist	Resist
15	63	13	363.3	Resist	Resist	Resist
20	76	13	418.6	Resist	Resist	Resist
25	89	18	501.0	Resist	Resist	Resist
30	102	21	571.6	Resist	Resist	Resist
35	121	23	666.5	Resist	Resist	Resist
40	127	24	697.9	Resist	Resist	Resist
55	143	30	790.9	Resist	Resist	Resist

Failure Mode?

Excavator size (t)	B=0.75	B=1	B=1.3
5	No Penetration	No Penetration	No Penetration
10	No Penetration	No Penetration	No Penetration
15	No Penetration	No Penetration	No Penetration
20	No Penetration	No Penetration	No Penetration
25	No Penetration	No Penetration	No Penetration
30	No Penetration	No Penetration	No Penetration
35	No Penetration	No Penetration	No Penetration
40	No Penetration	No Penetration	No Penetration
55	No Penetration	No Penetration	No Penetration

Hole Size (GP Teeth)?

Excavator size (t)	B=0.75	B=1	B=1.3
5	No Penetration	No Penetration	No Penetration
10	No Penetration	No Penetration	No Penetration
15	No Penetration	No Penetration	No Penetration
20	No Penetration	No Penetration	No Penetration
25	No Penetration	No Penetration	No Penetration
30	No Penetration	No Penetration	No Penetration
35	No Penetration	No Penetration	No Penetration
40	No Penetration	No Penetration	No Penetration
55	No Penetration	No Penetration	No Penetration

Mass flow rate, kg/s

Excavator size (t)	B=0.75	B=1	B=1.3
5	No Leak	No Leak	No Leak
10	No Leak	No Leak	No Leak
15	No Leak	No Leak	No Leak
20	No Leak	No Leak	No Leak
25	No Leak	No Leak	No Leak
30	No Leak	No Leak	No Leak
35	No Leak	No Leak	No Leak
40	No Leak	No Leak	No Leak
55	No Leak	No Leak	No Leak

Q, energy release rate, GJ/s

Excavator size (t)	B=0.75	B=1	B=1.3
5	0.00	0.00	0.00
10	0.00	0.00	0.00
15	0.00	0.00	0.00
20	0.00	0.00	0.00
25	0.00	0.00	0.00
30	0.00	0.00	0.00
35	0.00	0.00	0.00
40	0.00	0.00	0.00
55	0.00	0.00	0.00

TIGER TOOTH

Can a single point penetrate?

Excavator size (t)	Tiger Tooth L	W	Pipe Rp (kN)	B=0.75	B=1	B=1.3
5	6	5	92.1	Resist	Resist	Resist
10	8	7	110.9	Resist	Resist	Resist
15	11	9	130.8	Resist	Resist	Penetrate
20	13	10	142.3	Resist	Resist	Penetrate
25	11	17	148.9	Resist	Penetrate	Penetrate
30	12	20	157.1	Resist	Penetrate	Penetrate
35	14	22	168.3	Resist	Penetrate	Penetrate
40	16	25	180.2	Resist	Penetrate	Penetrate
55	17	25	184.9	Penetrate	Penetrate	Penetrate

Can a second point p Can a second point penetrate?

Multiplier factor 1.75

Excavator size (t)	Equiv Rp	B=0.75	B=1	B=1.3
5	161.3	No Penetration	No Penetration	No Penetration
10	194.0	No Penetration	No Penetration	No Penetration
15	228.9	No Penetration	No Penetration	Single
20	249.0	No Penetration	No Penetration	Single
25	260.6	No Penetration	Single	Single
30	274.8	No Penetration	Single	Single
35	294.5	No Penetration	Single	Single
40	315.4	No Penetration	Single	Single
55	323.6	Single	Single	Both

Failure Mode?

Excavator size (t)	B=0.75	B=1	B=1.3
5	No Penetration	No Penetration	No Penetration
10	No Penetration	No Penetration	No Penetration
15	No Penetration	No Penetration	Leak (Non HCA Compliant)
20	No Penetration	No Penetration	Leak (Non HCA Compliant)
25	No Penetration	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
30	No Penetration	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
35	No Penetration	Rupture	Rupture
40	No Penetration	Rupture	Rupture
55	Rupture	Rupture	Rupture

Hole Size for Tiger Teeth?

Excavator size (t)	B=0.75	B=1	B=1.3
5	No Penetration	No Penetration	No Penetration
10	No Penetration	No Penetration	No Penetration
15	No Penetration	No Penetration	20
20	No Penetration	No Penetration	25
25	No Penetration	25	25
30	No Penetration	30	30
35	No Penetration	Rupture	Rupture
40	No Penetration	Rupture	Rupture
55	Rupture	Rupture	Rupture

Mass flow rate, kg/s

Excavator size (t)	B=0.75	B=1	B=1.3
5	No Leak	No Leak	No Leak
10	No Leak	No Leak	No Leak
15	No Leak	No Leak	3.32
20	No Leak	No Leak	5.18
25	No Leak	5.18	5.18
30	No Leak	7.46	7.46
35	No Leak	1369.81	1369.81
40	No Leak	1369.81	1369.81
55	1369.81	1369.81	1369.81

Q, energy release rate, GJ/s

Excavator size (t)	B=0.75	B=1	B=1.3
5	0.00	0.00	0.00
10	0.00	0.00	0.00
15	0.00	0.00	0.22
20	0.00	0.00	0.34
25	0.00	0.34	0.34
30	0.00	0.49	0.49
35	0.00	90.18	90.18
40	0.00	90.18	90.18
55	90.18	90.18	90.18

PENETRATION TOOTH

Penetration?

Excavator size (t)	GP Tooth L	W	Pipe Rp (kN)	B=0.75	B=1	B=1.3
5	6	5	92.1	Resist	Resist	Resist
10	8	7	110.9	Resist	Resist	Resist
15	11	9	130.8	Resist	Resist	Penetrate
20	13	10	142.3	Resist	Resist	Penetrate
25	11	17	148.9	Resist	Penetrate	Penetrate
30	12	20	157.1	Resist	Penetrate	Penetrate
35	14	22	168.3	Resist	Penetrate	Penetrate
40	16	25	180.2	Resist	Penetrate	Penetrate
55	17	25	184.9	Penetrate	Penetrate	Penetrate

Failure Mode?

Excavator size (t)	B=0.75	B=1	B=1.3
5	No Penetration	No Penetration	No Penetration
10	No Penetration	No Penetration	No Penetration
15	No Penetration	No Penetration	Leak (Non HCA Compliant)
20	No Penetration	No Penetration	Leak (Non HCA Compliant)
25	No Penetration	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
30	No Penetration	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
35	No Penetration	Rupture	Rupture
40	No Penetration	Rupture	Rupture
55	Rupture	Rupture	Rupture

Hole Size (Penetration Tooth)

Excavator size (t)	B=0.75	B=1	B=1.3
5	No Penetration	No Penetration	No Penetration
10	No Penetration	No Penetration	No Penetration
15	No Penetration	No Penetration	55
20	No Penetration	No Penetration	60
25	No Penetration	65	65
30	No Penetration	70	70
35	No Penetration	Rupture	Rupture
40	No Penetration	Rupture	Rupture
55	Rupture	Rupture	Rupture

Mass flow rate, kg/s

Excavator size (t)	B=0.75	B=1	B=1.3
5	No Leak	No Leak	No Leak
10	No Leak	No Leak	No Leak
15	No Leak	No Leak	25.09
20	No Leak	No Leak	29.86
25	No Leak	35.04	35.04
30	No Leak	40.64	40.64
35	No Leak	1369.81	1369.81
40	No Leak	1369.81	1369.81
55	1369.81	1369.81	1369.81

Q, energy release rate, GJ/s

Excavator size (t)	B=0.75	B=1	B=1.3
5	0.00	0.00	0.00
10	0.00	0.00	0.00
15	0.00	0.00	1.65
20	0.00	0.00	1.97
25	0.00	2.31	2.31
30	0.00	2.68	2.68
35	0.00	90.18	90.18
40	0.00	90.18	90.18
55	90.18	90.18	90.18

PIPELINE PENETRATION CALCULATIONS

AS 2885.1 - 2012 - Appendix M

RBP DN400 8.1 mm X70

tw		8.1	mm				
MAOP		9.6	MPa				
CDL		152	mm				
Pipe Grade	API 5L	X70		σu	570	MPa	(lookup value)
OD, mm		406.4	mm				
Gas density, rho		0.562	kg/sm3				
GHV, MJ/sm3		37	MJ/sm3				

GP TOOTH

Penetration?

Excavator size (t)	GP Tooth					
	L	W	Pipe Rp (kN)	B=0.75	B=1	B=1.3
5	51	4	228.5	Resist	Resist	Resist
10	56	14	355.8	Resist	Resist	Resist
15	63	13	382.2	Resist	Resist	Resist
20	76	13	440.4	Resist	Resist	Resist
25	89	18	527.1	Resist	Resist	Resist
30	102	21	601.3	Resist	Resist	Resist
35	121	23	701.1	Resist	Resist	Resist
40	127	24	734.1	Resist	Resist	Resist
55	143	30	832.0	Resist	Resist	Resist

Failure Mode?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration

Hole Size (GP Teeth)?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration

Mass flow rate, kg/s

B=0.75	B=1	B=1.3
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak

Q, energy release rate, GJ/s

B=0.75	B=1	B=1.3
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00

TIGER TOOTH

Can a single point penetrate?

Excavator size (t)	Tiger Tooth					
	L	W	Pipe Rp (kN)	B=0.75	B=1	B=1.3
5	6	5	96.9	Resist	Resist	Resist
10	8	7	116.6	Resist	Resist	Resist
15	11	9	137.6	Resist	Resist	Resist
20	13	10	149.7	Resist	Resist	Penetrate
25	11	17	156.7	Resist	Penetrate	Penetrate
30	12	20	165.2	Resist	Penetrate	Penetrate
35	14	22	177.0	Resist	Penetrate	Penetrate
40	16	25	189.6	Resist	Penetrate	Penetrate
55	17	25	194.5	Penetrate	Penetrate	Penetrate

Can a second point p Can a second point penetrate?

Multiplier factor 1.75

Equiv Rp	B=0.75	B=1	B=1.3
169.6	No Penetration	No Penetration	No Penetration
204.1	No Penetration	No Penetration	No Penetration
240.8	No Penetration	No Penetration	No Penetration
262.0	No Penetration	No Penetration	Single
274.1	No Penetration	Single	Single
289.1	No Penetration	Single	Single
309.7	No Penetration	Single	Single
331.7	No Penetration	Single	Single
340.4	Single	Single	Both

Failure Mode?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	Leak
No Penetration	Leak	Leak
No Penetration	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
No Penetration	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
No Penetration	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
Leak (Non HCA Compliant)	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)

Hole Size for Tiger Teeth?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	25
No Penetration	25	25
No Penetration	30	30
No Penetration	30	30
No Penetration	35	35
35	35	125

Mass flow rate, kg/s

B=0.75	B=1	B=1.3
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	5.18
No Leak	5.18	5.18
No Leak	7.46	7.46
No Leak	7.46	7.46
No Leak	10.16	10.16
10.16	10.16	129.59

Q, energy release rate, GJ/s

B=0.75	B=1	B=1.3
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.34
0.00	0.34	0.34
0.00	0.49	0.49
0.00	0.49	0.49
0.00	0.67	0.67
0.67	0.67	8.53

PENETRATION TOOTH

Penetration?

Excavator size (t)	GP Tooth					
	L	W	Pipe Rp (kN)	B=0.75	B=1	B=1.3
5	6	5	96.9	Resist	Resist	Resist
10	8	7	116.6	Resist	Resist	Resist
15	11	9	137.6	Resist	Resist	Resist
20	13	10	149.7	Resist	Resist	Penetrate
25	11	17	156.7	Resist	Penetrate	Penetrate
30	12	20	165.2	Resist	Penetrate	Penetrate
35	14	22	177.0	Resist	Penetrate	Penetrate
40	16	25	189.6	Resist	Penetrate	Penetrate
55	17	25	194.5	Penetrate	Penetrate	Penetrate

Failure Mode?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	Leak
No Penetration	Leak	Leak
No Penetration	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
No Penetration	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
No Penetration	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
Leak (Non HCA Compliant)	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)

Hole Size (Penetration Tooth)

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	60
No Penetration	65	65
No Penetration	70	70
No Penetration	80	80
No Penetration	90	90
90	90	90

Mass flow rate, kg/s

B=0.75	B=1	B=1.3
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	29.86
No Leak	35.04	35.04
No Leak	40.64	40.64
No Leak	53.08	53.08
No Leak	67.18	67.18
67.18	67.18	67.18

Q, energy release rate, GJ/s

B=0.75	B=1	B=1.3
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	1.97
0.00	2.31	2.31
0.00	2.68	2.68
0.00	3.49	3.49
0.00	4.42	4.42
4.42	4.42	4.42

PIPELINE PENETRATION CALCULATIONS

AS 2885.1 - 2012 - Appendix M

RBP DN400 8.85 mm X80

tw		8.85	mm				
MAOP		9.6	MPa				
CDL		206	mm				
Pipe Grade	API 5L	X70		σu	570	MPa	(lookup value)
OD, mm		406.4	mm				
Gas density, rho		0.562	kg/sm3				
GHV, MJ/sm3		37	MJ/sm3				

GP TOOTH

Penetration?

Excavator size (t)	GP Tooth L	W	Pipe Rp (kN)	B=0.75	B=1	B=1.3
5	51	4	249.6	Resist	Resist	Resist
10	56	14	388.8	Resist	Resist	Resist
15	63	13	417.6	Resist	Resist	Resist
20	76	13	481.2	Resist	Resist	Resist
25	89	18	575.9	Resist	Resist	Resist
30	102	21	657.0	Resist	Resist	Resist
35	121	23	766.0	Resist	Resist	Resist
40	127	24	802.1	Resist	Resist	Resist
55	143	30	909.0	Resist	Resist	Resist

Failure Mode?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration

Hole Size (GP Teeth)?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration

Mass flow rate, kg/s

B=0.75	B=1	B=1.3
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak

Q, energy release rate, GJ/s

B=0.75	B=1	B=1.3
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00

TIGER TOOTH

Can a single point penetrate?

Excavator size (t)	Tiger Tooth L	W	Pipe Rp (kN)	B=0.75	B=1	B=1.3
5	6	5	105.9	Resist	Resist	Resist
10	8	7	127.4	Resist	Resist	Resist
15	11	9	150.3	Resist	Resist	Resist
20	13	10	163.6	Resist	Resist	Penetrate
25	11	17	171.2	Resist	Resist	Penetrate
30	12	20	180.5	Resist	Penetrate	Penetrate
35	14	22	193.4	Resist	Penetrate	Penetrate
40	16	25	207.1	Resist	Penetrate	Penetrate
55	17	25	212.5	Penetrate	Penetrate	Penetrate

Can a second point p **Can a second point penetrate?**

Multiplier factor 1.75

Equiv Rp	B=0.75	B=1	B=1.3
185.3	No Penetration	No Penetration	No Penetration
223.0	No Penetration	No Penetration	No Penetration
263.1	No Penetration	No Penetration	No Penetration
286.2	No Penetration	No Penetration	Single
299.5	No Penetration	No Penetration	Single
315.9	No Penetration	Single	Single
338.4	No Penetration	Single	Single
362.5	No Penetration	Single	Single
371.9	Single	Single	Both

Failure Mode?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	Leak
No Penetration	No Penetration	Leak
No Penetration	Leak	Leak
No Penetration	Leak	Leak
No Penetration	Leak	Leak
Leak (Non HCA Compliant)	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)

Hole Size for Tiger Teeth?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	25
No Penetration	No Penetration	25
No Penetration	30	30
No Penetration	30	30
No Penetration	35	35
35	35	125

Mass flow rate, kg/s

B=0.75	B=1	B=1.3
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	5.18
No Leak	No Leak	5.18
No Leak	7.46	7.46
No Leak	7.46	7.46
No Leak	10.16	10.16
10.16	10.16	129.59

Q, energy release rate, GJ/s

B=0.75	B=1	B=1.3
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.34
0.00	0.00	0.34
0.00	0.49	0.49
0.00	0.49	0.49
0.00	0.67	0.67
0.67	0.67	8.53

PENETRATION TOOTH

Penetration?

Excavator size (t)	GP Tooth L	W	Pipe Rp (kN)	B=0.75	B=1	B=1.3
5	6	5	105.9	Resist	Resist	Resist
10	8	7	127.4	Resist	Resist	Resist
15	11	9	150.3	Resist	Resist	Resist
20	13	10	163.6	Resist	Resist	Penetrate
25	11	17	171.2	Resist	Resist	Penetrate
30	12	20	180.5	Resist	Penetrate	Penetrate
35	14	22	193.4	Resist	Penetrate	Penetrate
40	16	25	207.1	Resist	Penetrate	Penetrate
55	17	25	212.5	Penetrate	Penetrate	Penetrate

Failure Mode?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	Leak
No Penetration	No Penetration	Leak
No Penetration	Leak	Leak
No Penetration	Leak	Leak
No Penetration	Leak	Leak
Leak (Non HCA Compliant)	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)

Hole Size (Penetration Tooth)

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	60
No Penetration	No Penetration	65
No Penetration	70	70
No Penetration	80	80
No Penetration	90	90
90	90	90

Mass flow rate, kg/s

B=0.75	B=1	B=1.3
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	29.86
No Leak	No Leak	35.04
No Leak	40.64	40.64
No Leak	53.08	53.08
No Leak	67.18	67.18
67.18	67.18	67.18

Q, energy release rate, GJ/s

B=0.75	B=1	B=1.3
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	1.97
0.00	0.00	2.31
0.00	2.68	2.68
0.00	3.49	3.49
0.00	4.42	4.42
4.42	4.42	4.42

PIPELINE PENETRATION CALCULATIONS

AS 2885.1 - 2012 - Appendix M

RBP DN400 9.5 mm X60

tw		9.5	mm			
MAOP		9.6	MPa			
CDL		170	mm			
Pipe Grade	API 5L	X60		σu	520 MPa	(lookup value)
OD, mm		406.4	mm			
Gas density, rho		0.562	kg/sm3			
GHV, MJ/sm3		37	MJ/sm3			

GP TOOTH

Penetration?

Excavator size (t)	GP Tooth L	W	Pipe Rp (kN)	B=0.75	B=1	B=1.3
5	51	4	254.3	Resist	Resist	Resist
10	56	14	396.0	Resist	Resist	Resist
15	63	13	425.4	Resist	Resist	Resist
20	76	13	490.2	Resist	Resist	Resist
25	89	18	586.6	Resist	Resist	Resist
30	102	21	669.3	Resist	Resist	Resist
35	121	23	780.3	Resist	Resist	Resist
40	127	24	817.1	Resist	Resist	Resist
55	143	30	926.0	Resist	Resist	Resist

Failure Mode?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration

Hole Size (GP Teeth)?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration

Mass flow rate, kg/s

B=0.75	B=1	B=1.3
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak

Q, energy release rate, GJ/s

B=0.75	B=1	B=1.3
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00

TIGER TOOTH

Can a single point penetrate?

Excavator size (t)	Tiger Tooth L	W	Pipe Rp (kN)	B=0.75	B=1	B=1.3
5	6	5	107.9	Resist	Resist	Resist
10	8	7	129.8	Resist	Resist	Resist
15	11	9	153.1	Resist	Resist	Resist
20	13	10	166.6	Resist	Resist	Penetrate
25	11	17	174.4	Resist	Resist	Penetrate
30	12	20	183.9	Resist	Penetrate	Penetrate
35	14	22	197.0	Resist	Penetrate	Penetrate
40	16	25	211.0	Resist	Penetrate	Penetrate
55	17	25	216.5	Penetrate	Penetrate	Penetrate

Can a second point p **Can a second point penetrate?**

Multiplier factor 1.75

Equiv Rp	B=0.75	B=1	B=1.3
188.8	No Penetration	No Penetration	No Penetration
227.1	No Penetration	No Penetration	No Penetration
268.0	No Penetration	No Penetration	No Penetration
291.6	No Penetration	No Penetration	Single
305.1	No Penetration	No Penetration	Single
321.8	No Penetration	Single	Single
344.7	No Penetration	Single	Single
369.2	No Penetration	Single	Single
378.8	Single	Single	Both

Failure Mode?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	Leak
No Penetration	No Penetration	Leak
No Penetration	Leak	Leak
No Penetration	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
No Penetration	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
Leak (Non HCA Compliant)	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)

Hole Size for Tiger Teeth?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	25
No Penetration	No Penetration	25
No Penetration	30	30
No Penetration	30	30
No Penetration	35	35
35	35	125

Mass flow rate, kg/s

B=0.75	B=1	B=1.3
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	5.18
No Leak	No Leak	5.18
No Leak	7.46	7.46
No Leak	7.46	7.46
No Leak	10.16	10.16
10.16	10.16	129.59

Q, energy release rate, GJ/s

B=0.75	B=1	B=1.3
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.34
0.00	0.00	0.34
0.00	0.49	0.49
0.00	0.49	0.49
0.00	0.67	0.67
0.67	0.67	8.53

PENETRATION TOOTH

Penetration?

Excavator size (t)	GP Tooth L	W	Pipe Rp (kN)	B=0.75	B=1	B=1.3
5	6	5	107.9	Resist	Resist	Resist
10	8	7	129.8	Resist	Resist	Resist
15	11	9	153.1	Resist	Resist	Resist
20	13	10	166.6	Resist	Resist	Penetrate
25	11	17	174.4	Resist	Resist	Penetrate
30	12	20	183.9	Resist	Penetrate	Penetrate
35	14	22	197.0	Resist	Penetrate	Penetrate
40	16	25	211.0	Resist	Penetrate	Penetrate
55	17	25	216.5	Penetrate	Penetrate	Penetrate

Failure Mode?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	Leak
No Penetration	No Penetration	Leak
No Penetration	Leak	Leak
No Penetration	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
No Penetration	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)
Leak (Non HCA Compliant)	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)

Hole Size (Penetration Tooth)

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	60
No Penetration	No Penetration	65
No Penetration	70	70
No Penetration	80	80
No Penetration	90	90
90	90	90

Mass flow rate, kg/s

B=0.75	B=1	B=1.3
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	29.86
No Leak	No Leak	35.04
No Leak	40.64	40.64
No Leak	53.08	53.08
No Leak	67.18	67.18
67.18	67.18	67.18

Q, energy release rate, GJ/s

B=0.75	B=1	B=1.3
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	1.97
0.00	0.00	2.31
0.00	2.68	2.68
0.00	3.49	3.49
0.00	4.42	4.42
4.42	4.42	4.42

PIPELINE PENETRATION CALCULATIONS

AS 2885.1 - 2012 - Appendix M

RBP DN400 9.7 mm X70

tw		9.7	mm			
MAOP		9.6	MPa			
CDL		208	mm			
Pipe Grade	API 5L	X70		σu	570 MPa	(lookup value)
OD, mm		406.4	mm			
Gas density, rho		0.562	kg/sm3			
GHV, MJ/sm3		37	MJ/sm3			

GP TOOTH

Penetration?

Excavator size (t)	GP Tooth L	W	Pipe Rp (kN)	B=0.75	B=1	B=1.3
5	51	4	273.6	Resist	Resist	Resist
10	56	14	426.1	Resist	Resist	Resist
15	63	13	457.7	Resist	Resist	Resist
20	76	13	527.4	Resist	Resist	Resist
25	89	18	631.2	Resist	Resist	Resist
30	102	21	720.1	Resist	Resist	Resist
35	121	23	839.6	Resist	Resist	Resist
40	127	24	879.1	Resist	Resist	Resist
55	143	30	996.3	Resist	Resist	Resist

Failure Mode?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration

Hole Size (GP Teeth)?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration

Mass flow rate, kg/s

B=0.75	B=1	B=1.3
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak

Q, energy release rate, GJ/s

B=0.75	B=1	B=1.3
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00

TIGER TOOTH

Can a single point penetrate?

Excavator size (t)	Tiger Tooth L	W	Pipe Rp (kN)	B=0.75	B=1	B=1.3
5	6	5	116.1	Resist	Resist	Resist
10	8	7	139.6	Resist	Resist	Resist
15	11	9	164.8	Resist	Resist	Resist
20	13	10	179.3	Resist	Resist	Resist
25	11	17	187.6	Resist	Resist	Penetrate
30	12	20	197.8	Resist	Resist	Penetrate
35	14	22	212.0	Resist	Penetrate	Penetrate
40	16	25	227.0	Resist	Penetrate	Penetrate
55	17	25	232.9	Resist	Penetrate	Penetrate

Can a second point p **Can a second point penetrate?**

Multiplier factor 1.75

Equiv Rp	B=0.75	B=1	B=1.3
203.1	No Penetration	No Penetration	No Penetration
244.4	No Penetration	No Penetration	No Penetration
288.3	No Penetration	No Penetration	No Penetration
313.7	No Penetration	No Penetration	No Penetration
328.3	No Penetration	No Penetration	Single
346.2	No Penetration	No Penetration	Single
370.9	No Penetration	Single	Single
397.3	No Penetration	Single	Single
407.6	No Penetration	Single	Single

Failure Mode?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	Leak
No Penetration	No Penetration	Leak
No Penetration	Leak	Leak
No Penetration	Leak	Leak
No Penetration	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)

Hole Size for Tiger Teeth?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	25
No Penetration	No Penetration	30
No Penetration	30	30
No Penetration	35	35
No Penetration	35	35

Mass flow rate, kg/s

B=0.75	B=1	B=1.3
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	5.18
No Leak	No Leak	7.46
No Leak	7.46	7.46
No Leak	10.16	10.16
No Leak	10.16	10.16

Q, energy release rate, GJ/s

B=0.75	B=1	B=1.3
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.34
0.00	0.00	0.49
0.00	0.49	0.49
0.00	0.67	0.67
0.00	0.67	0.67

PENETRATION TOOTH

Penetration?

Excavator size (t)	GP Tooth L	W	Pipe Rp (kN)	B=0.75	B=1	B=1.3
5	6	5	116.1	Resist	Resist	Resist
10	8	7	139.6	Resist	Resist	Resist
15	11	9	164.8	Resist	Resist	Resist
20	13	10	179.3	Resist	Resist	Resist
25	11	17	187.6	Resist	Resist	Penetrate
30	12	20	197.8	Resist	Resist	Penetrate
35	14	22	212.0	Resist	Penetrate	Penetrate
40	16	25	227.0	Resist	Penetrate	Penetrate
55	17	25	232.9	Resist	Penetrate	Penetrate

Failure Mode?

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	Leak
No Penetration	No Penetration	Leak
No Penetration	Leak	Leak
No Penetration	Leak	Leak
No Penetration	Leak (Non HCA Compliant)	Leak (Non HCA Compliant)

Hole Size (Penetration Tooth)

B=0.75	B=1	B=1.3
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	No Penetration
No Penetration	No Penetration	65
No Penetration	No Penetration	70
No Penetration	80	80
No Penetration	90	90
No Penetration	90	90

Mass flow rate, kg/s

B=0.75	B=1	B=1.3
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	No Leak
No Leak	No Leak	35.04
No Leak	No Leak	40.64
No Leak	53.08	53.08
No Leak	67.18	67.18
No Leak	67.18	67.18

Q, energy release rate, GJ/s

B=0.75	B=1	B=1.3
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	2.31
0.00	0.00	2.68
0.00	3.49	3.49
0.00	4.42	4.42
0.00	4.42	4.42

Appendix D

Critical Defect Length Calculations

CALCULATION SHEET

APA Group

320-CAL-AM-0118

Project Title	*1969 DN200 MAOP Study - CDL*		Project No	
Designed	*Chris Connor*	Date	*30/09/2015*	
Checked	*Martin Jacobson*	Date	*1/10/2015*	Sheet *1* of *4*
Approved	Francis Carroll	Date	*1/10/2015*	

Critical Defect Length AS2885.1-2012 Section 4.8.5

The equations to determine the critical length of an axial through thickness flaw can be presented as follows:

Method 2 - For existing pipe, knowing toughness values (Low toughness steel)

For CDL of low toughness pipe with known Charpy V-notch Test energy (CVN, in Joules), and Fracture Area (Ac, in mm^2)

AS2885.1-2012 Eqn 4.8.5(4)

$$K_C{}^2 = \frac{8c(\sigma_{flow})^2}{\pi} \ln.\sec\left(\frac{\pi M_T \sigma_H}{2\sigma_{flow}}\right)$$

AS2885.1-2012 Eqn 4.8.5(5)

$$\frac{K_C{}^2}{E} = \frac{1000CVN}{A_C}$$

The above equations are simultaniously solved for "c", giving the CDL, where:

σ_{flow}	Flow stress = SMYS + 10 ksi for fracture control	MPa
K_C	In plane stress intensification factor (fracture initiation toughness)	$MPa/mm^{0.5}$
c	Half of the length of an axial through wall flaw	mm
M_T	Folias factor	

$$M_T = \left[1 + 1.255\frac{c^2}{\frac{D}{2}t_W} - 0.0135\frac{c^4}{\left(\frac{D}{2}\right)^2 (t_W)^2}\right]^{0.5}$$

σ_H	Hoop stress	MPa

$$\sigma_H = \frac{P_d D}{2t_W}$$

P_D	Design pressure	MPa
t_W	Wall thickness	mm
D	Nominal outside diameter = Pipe diameter = Pipeline diameter	mm
E	Young's modulus	MPa

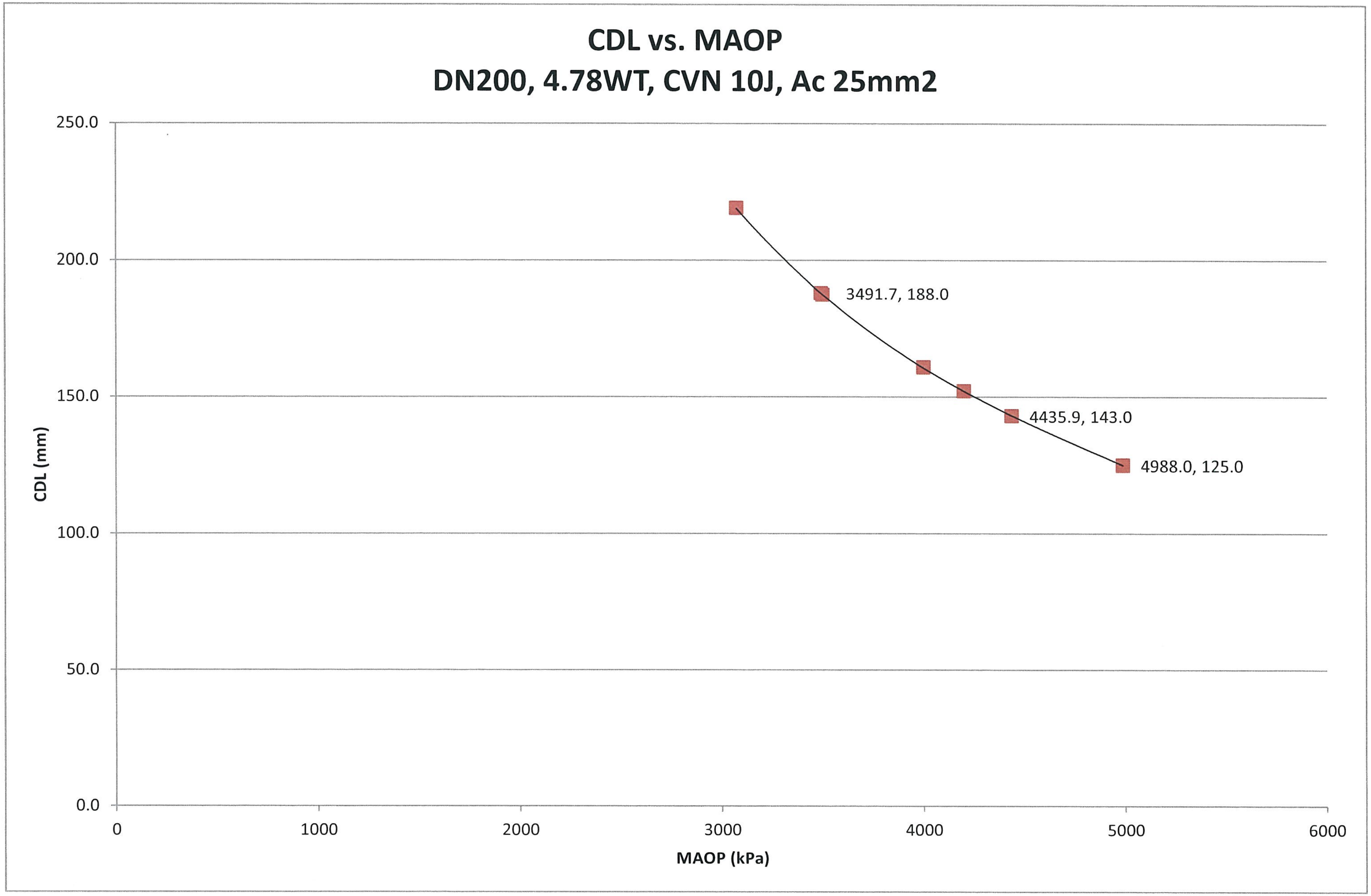
Critical Defect Length Clause 4.8.5 AS 2885.1 - 2012												*Input*				
RBP DN200 4.78WT												*Goal seek*				
Through Wall Defect										**CDL Method 2 Calculation (preferred for original RBP pipe)** Low toughness steel CDL *[toughness dependent] - (note 3)*						
Pipeline	License	Diameter (mm)	Grade (X_)	SMYS (MPa)	σ_{υ} (MPa)	WT (mm)	Pd (kPa)	σ_{flow} (MPa)	σ_H (MPa)	CVN (J) (Note 4)	Ac (mm2) (Note 4)	Kc^2 - cl4.8.5 (5) (Mpa^2/mm)	c (mm)	Kc^2 - cl4.8.5 (4) (Mpa^2/mm)	Mt	**CDL (mm)**
Changing MAOP																
RBP	2	219.1	42	289.59	414	4.78	4200	358.54	96.26	10	25	82000000	76.09	82000000	3.64	**152.2**
RBP	2	219.1	42	289.59	414	4.78	4000	358.54	91.68	10	25	82000000	80.42	82000000	3.80	**160.8**
RBP	2	219.1	42	289.59	414	4.78	3500	358.54	80.22	10	25	82000000	93.73	82000000	4.27	**187.5**
RBP	2	219.1	42	289.59	414	4.78	3073	358.54	70.42	10	25	82000000	109.55	81999999	4.76	**219.1**
Changine CDL																
RBP	2	219.1	42	289.59	414	4.78	4988.0	358.54	114.316	10	25	82000000	62.50	81999951	3.10	**125.0**
RBP	2	219.1	42	289.59	414	4.78	4435.9	358.54	101.664	10	25	82000000	71.50	81999585	3.46	**143.0**
RBP	2	219.1	42	289.59	414	4.78	3491.7	358.54	80.024	10	25	82000000	94.00	82000076	4.28	**188.0**
Changing CVN																
RBP	2	219.1	42	289.59	414	4.78	4200	358.54	96.2573	3	25	24600000	60.71	24600000	3.03	**121.4**
RBP	2	219.1	42	289.59	414	4.78	4200	358.54	96.2573	4	25	32800000	65.23	32800000	3.21	**130.5**
RBP	2	219.1	42	289.59	414	4.78	4200	358.54	96.2573	5	25	41000000	68.53	41000000	3.34	**137.1**
RBP	2	219.1	42	289.59	414	4.78	4200	358.54	96.2573	8	25	65600000	74.23	65600000	3.57	**148.5**
RBP	2	219.1	42	289.59	414	4.78	4200	358.54	96.2573	10	25	82000000	76.09	82000000	3.64	**152.2**
RBP	2	219.1	42	289.59	414	4.78	4200	358.54	96.2573	13	25	106600000	77.47	106600000	3.69	**154.9**

E (young's)	205000	Mpa

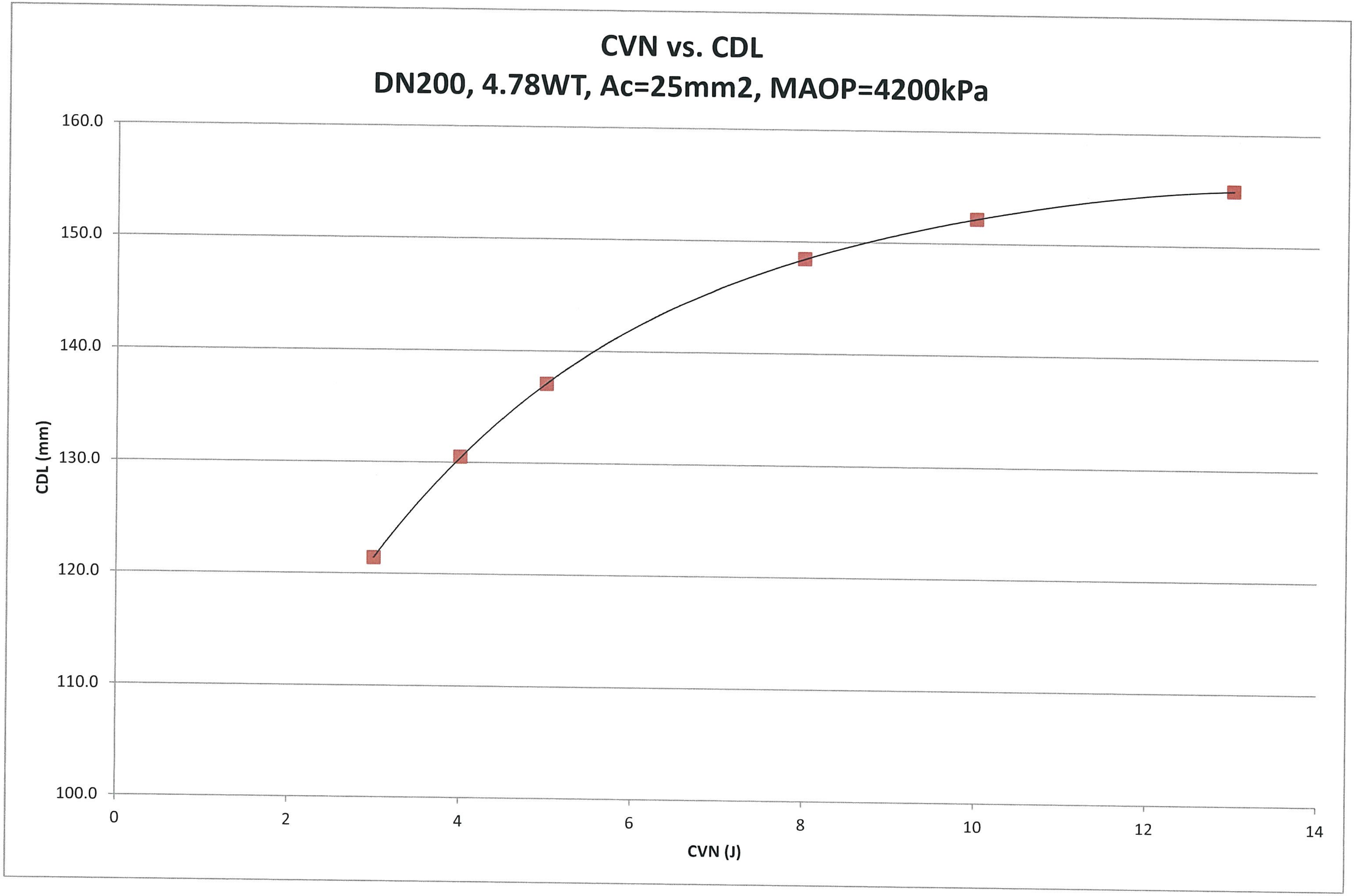
Notes

1. Critcal hoop stress, Flow stress and M factor equations are taken from AS2885.1:2012 Clause 4.8.5
2. MAOP hoop stress is calculated using Barlow's equation.
3. Both equations 4.8.5 (4) and (5) have been used, as to some extent CDL can depend on CVN. If CVN is unknown, recommend assuming 27J minimum.
4. Taken from Charpy Test Results on 1969 DN300 X42, 5.16WT.

Calculated:	C. Connor	*Signature*	Date	30/09/2015
Checked:	M. Jacobson	*Signature*	Date	1/10/2015



CDL vs. MAOP
DN200, 4.78WT, CVN 10J, Ac 25mm2
250.0
200.0
150.0
100.0
50.0
0.0
CDL (mm)
3491.7, 188.0
4435.9, 143.0
4988.0, 125.0
0
1000
2000
3000
4000
5000
6000
MAOP (kPa)


CVN vs. CDL
DN200, 4.78WT, Ac=25mm2, MAOP=4200kPa
160.0
150.0
140.0
130.0
120.0
110.0
100.0
CDL (mm)
0
2
4
6
8
10
12
14
CVN (J)

CALCULATION SHEET

APA Group

320-CAL-AM-0117

Project Title	*1969 DN250 MAOP Study - CDL*		Project No
Designed	Chris Connor	Date	30/09/2015
Checked	Martin Jacobson	Date	1/10/2015 Sheet *1 of 6*
Approved	Francis Carroll	Date	1/10/2015

Critical Defect Length AS2885.1-2012 Section 4.8.5

The equations to determine the critical length of an axial through thickness flaw can be presented as follows:

Method 2 - For existing pipe, knowing toughness values (Low toughness steel)

For CDL of low toughness pipe with known Charpy V-notch Test energy (CVN, in Joules), and Fracture Area (Ac, in mm^2)

AS2885.1-2012 Eqn 4.8.5(4)

$$K_C{}^2 = \frac{8c(\sigma_{flow})^2}{\pi} \ln.\sec\left(\frac{\pi M_T \sigma_H}{2\sigma_{flow}}\right)$$

AS2885.1-2012 Eqn 4.8.5(5)

$$\frac{K_C{}^2}{E} = \frac{1000CVN}{A_C}$$

The above equations are simultaniously solved for "c", giving the CDL, where:

σ_{flow}	Flow stress = SMYS + 10 ksi for fracture control	MPa
K_C	In plane stress intensification factor (fracture initiation toughness)	MPa/mm$^{0.5}$
c	Half of the length of an axial through wall flaw	mm
M_T	Folias factor	

$$M_T = \left[1 + 1.255\frac{c^2}{\frac{D}{2}t_W} - 0.0135\frac{c^4}{\left(\frac{D}{2}\right)^2 (t_W)^2}\right]^{0.5}$$

σ_H	Hoop stress	MPa

$$\sigma_H = \frac{P_d D}{2t_W}$$

P_D	Design pressure	MPa
t_W	Wall thickness	mm
D	Nominal outside diameter = Pipe diameter = Pipeline diameter	mm
E	Young's modulus	MPa

Critical Defect Length Clause 4.8.5 AS 2885.1 - 2012

RBP DN250 4.78WT

Input

Goal seek

CDL Method 2 Calculation (preferred for original RBP pipe)

Low toughness steel CDL

[toughness dependent] - (note 3)

Through Wall Defect

Pipeline	License	Diameter (mm)	Grade (X_)	SMYS (MPa)	σ_{u} (MPa)	WT (mm)	Pd (kPa)	σ_{flow} (MPa)	σ_{H} (MPa)	CVN (J) (Note 4)	Ac (mm2) (Note 4)	Kc^2 - cl4.8.5 (5) (Mpa^2/mm)	c (mm)	Kc^2 - cl4.8.5 (4) (Mpa^2/mm)	Mt	**CDL (mm)**
Changing MAOP																
RBP	2	273.1	46	317.17	435	4.78	7136	386.12	203.86	6	25	49200000	36.17	49199999	1.86	**72.3**
RBP	2	273.1	46	317.17	435	4.78	7000	386.12	199.97	6	25	49200000	37.09	49200000	1.89	**74.2**
RBP	2	273.1	46	317.17	435	4.78	6500	386.12	185.69	6	25	49200000	40.70	49200000	2.02	**81.4**
RBP	2	273.1	46	317.17	435	4.78	6000	386.12	171.41	6	25	49200000	44.75	49199999	2.17	**89.5**
RBP	2	273.1	46	317.17	435	4.78	5500	386.12	157.12	6	25	49200000	49.35	49200000	2.34	**98.7**
RBP	2	273.1	46	317.17	435	4.78	5000	386.12	142.84	6	25	49200000	54.66	49200000	2.54	**109.3**
RBP	2	273.1	46	317.17	435	4.78	4500	386.12	128.56	6	25	49200000	60.93	49200000	2.77	**121.9**
RBP	2	273.1	46	317.17	435	4.78	4000	386.12	114.27	6	25	49200000	68.50	49200000	3.05	**137.0**
RBP	2	273.1	46	317.17	435	4.78	3500	386.12	99.99	6	25	49200000	77.94	49200000	3.39	**155.9**
RBP	2	273.1	46	317.17	435	4.78	3000	386.12	85.71	6	25	49200000	90.26	49200000	3.82	**180.5**
Changing CDL																
RBP	2	273.1	46	317.17	435	4.78	4387.7	386.12	125.343	6	25	49200000	62.50	49199534	2.83	**125.0**
RBP	2	273.1	46	317.17	435	4.78	3827.8	386.12	109.347	6	25	49200000	71.50	49199695	3.16	**143.0**
RBP	2	273.1	46	317.17	435	4.78	2875.1	386.12	82.1335	6	25	49200000	94.00	49199996	3.94	**188.0**
Changing CVN																
RBP	2	273.1	46	317.17	435	4.78	7136	386.12	203.854	2.5	25	20500000	31.06	20500000	1.68	**62.1**
RBP	2	273.1	46	317.17	435	4.78	7136	386.12	203.854	5	25	41000000	35.50	41000000	1.84	**71.0**
RBP	2	273.1	46	317.17	435	4.78	7136	386.12	203.854	7.5	25	61500000	36.70	61500000	1.88	**73.4**
RBP	2	273.1	46	317.17	435	4.78	7136	386.12	203.854	10	25	82000000	37.01	82000000	1.89	**74.0**
RBP	2	273.1	46	317.17	435	4.78	7136	386.12	203.854	12.5	25	102500000	37.09	102500000	1.89	**74.2**

E (young's)	205000	Mpa

Notes

1. Critcal hoop stress, Flow stress and M factor equations are taken from AS2885.1:2012 Clause 4.8.5
2. MAOP hoop stress is calculated using Barlow's equation.
3. Both equations 4.8.5 (4) and (5) have been used, as to some extent CDL can depend on CVN. If CVN is unknown, recommend assuming 27J minimum.
4. Taken from Charpy Test Results on 1969 DN250 X46, 6.35WT, Based on the avarage of samples taken from the weld area, which would yield low energy results when compared to the pipe body

Calculated:	C. Connor	*Signature*	Date	30/09/2015
Checked:	M. Jacobson	*Signature*	Date	1/10/2015

Critical Defect Length Clause 4.8.5 AS 2885.1 - 2012

RBP DN250 4.78WT

Input

Goal seek

Through Wall Defect

CDL Method 2 Calculation (preferred for original RBP pipe)
Low toughness steel CDL
[toughness dependent] - (note 3)

Pipeline	License	Diameter (mm)	Grade (X_)	SMYS (MPa)	σ_{υ} (MPa)	WT (mm)	Pd (kPa)	σ_{flow} (MPa)	σ_H (MPa)	CVN (J) (Note 4)	Ac (mm2) (Note 4)	Kc^2 - cl4.8.5 (5) (Mpa^2/mm)	c (mm)	Kc^2 - cl4.8.5 (4) (Mpa^2/mm)	Mt	**CDL (mm)**
Changing MAOP																
RBP	2	273.1	46	317.17	435	5.16	7136	386.12	188.85	6	25	49200000	41.26	49200000	1.99	**82.5**
RBP	2	273.1	46	317.17	435	5.16	7000	386.12	185.25	6	25	49200000	42.24	49200000	2.02	**84.5**
RBP	2	273.1	46	317.17	435	5.16	6500	386.12	172.02	6	25	49200000	46.08	49200000	2.16	**92.2**
RBP	2	273.1	46	317.17	435	5.16	6000	386.12	158.78	6	25	49200000	50.41	49200000	2.31	**100.8**
RBP	2	273.1	46	317.17	435	5.16	5500	386.12	145.55	6	25	49200000	55.35	49200000	2.49	**110.7**
RBP	2	273.1	46	317.17	435	5.16	5000	386.12	132.32	6	25	49200000	61.06	49200000	2.70	**122.1**
RBP	2	273.1	46	317.17	435	5.16	4500	386.12	119.09	6	25	49200000	67.82	49200000	2.94	**135.6**
RBP	2	273.1	46	317.17	435	5.16	4000	386.12	105.86	6	25	49200000	76.03	49200000	3.22	**152.1**
RBP	2	273.1	46	317.17	435	5.16	3500	386.12	92.63	6	25	49200000	86.31	49200000	3.57	**172.6**
RBP	2	273.1	46	317.17	435	5.16	3000	386.12	79.39	6	25	49200000	99.85	49200000	4.01	**199.7**
Changing CDL																
RBP	2	273.1	46	317.17	435	5.16	4886.3	386.12	129.307	6	25	49200000	62.50	49199759	2.75	**125.0**
RBP	2	273.1	46	317.17	435	5.16	4263.3	386.12	112.821	6	25	49200000	71.50	49200029	3.07	**143.0**
RBP	2	273.1	46	317.17	435	5.16	3197.9	386.12	84.6253	6	25	49200000	94.00	49200414	3.82	**188.0**
Changing CVN																
RBP	2	273.1	46	317.17	435	5.16	7136	386.12	188.841	2.5	25	20500000	34.83	20500000	1.77	**69.7**
RBP	2	273.1	46	317.17	435	5.16	7136	386.12	188.841	5	25	41000000	40.31	41000001	1.96	**80.6**
RBP	2	273.1	46	317.17	435	5.16	7136	386.12	188.841	7.5	25	61500000	42.08	61500000	2.02	**84.2**
RBP	2	273.1	46	317.17	435	5.16	7136	386.12	188.841	10	25	82000000	42.63	82000001	2.04	**85.3**
RBP	2	273.1	46	317.17	435	5.16	7136	386.12	188.841	12.5	25	102500000	42.80	102500000	2.04	**85.6**

E (young's)	205000	Mpa

Notes

1. Critcal hoop stress, Flow stress and M factor equations are taken from AS2885.1:2012 Clause 4.8.5
2. MAOP hoop stress is calculated using Barlow's equation.
3. Both equations 4.8.5 (4) and (5) have been used, as to some extent CDL can depend on CVN. If CVN is unknown, recommend assuming 27J minimum.
4. Taken from Charpy Test Results on 1969 DN250 X46, 6.35WT

Calculated:	C. Connor	*Signature*	Date	30/09/2015
Checked:	M. Jacobson	*Signature*	Date	1/10/2015

Critical Defect Length Clause 4.8.5 AS 2885.1 - 2012

RBP DN250 4.78WT

Input

Goal seek

CDL Method 2 Calculation (preferred for original RBP pipe)
Low toughness steel CDL
[toughness dependent] - (note 3)

Through Wall Defect

Pipeline	License	Diameter (mm)	Grade (X_)	SMYS (MPa)	σ_{υ} (MPa)	WT (mm)	Pd (kPa)	σ_{flow} (MPa)	σ_H (MPa)	CVN (J) (Note 4)	Ac (mm2) (Note 4)	Kc^2 - cl4.8.5 (5) (Mpa^2/mm)	c (mm)	Kc^2 - cl4.8.5 (4) (Mpa^2/mm)	Mt	**CDL (mm)**
Changing MAOP																
RBP	2	273.1	46	317.17	435	6.35	7136	386.12	153.46	6	25	49200000	57.08	49200000	2.35	**114.2**
RBP	2	273.1	46	317.17	435	6.35	7000	386.12	150.53	6	25	49200000	58.25	49200000	2.39	**116.5**
RBP	2	273.1	46	317.17	435	6.35	6500	386.12	139.78	6	25	49200000	62.87	49199999	2.54	**125.7**
RBP	2	273.1	46	317.17	435	6.35	6000	386.12	129.03	6	25	49200000	68.12	49200000	2.71	**136.2**
RBP	2	273.1	46	317.17	435	6.35	5500	386.12	118.28	6	25	49200000	74.14	49200000	2.90	**148.3**
RBP	2	273.1	46	317.17	435	6.35	5000	386.12	107.52	6	25	49200000	81.20	49200000	3.12	**162.4**
RBP	2	273.1	46	317.17	435	6.35	4500	386.12	96.77	6	25	49200000	89.62	49200000	3.39	**179.2**
RBP	2	273.1	46	317.17	435	6.35	4000	386.12	86.02	6	25	49200000	99.96	49200000	3.70	**199.9**
RBP	2	273.1	46	317.17	435	6.35	3500	386.12	75.27	6	25	49200000	113.14	49200000	4.07	**226.3**
RBP	2	273.1	46	317.17	435	6.35	3000	386.12	64.52	6	25	49200000	130.99	49200000	4.53	**262.0**
Changing CDL																
RBP	2	273.1	46	317.17	435	6.35	6538.27	386.12	140.599	6	25	49200000	62.50	49199560	2.53	**125.0**
RBP	2	273.1	46	317.17	435	6.35	5710.62	386.12	122.801	6	25	49200000	71.50	49199582	2.82	**143.0**
RBP	2	273.1	46	317.17	435	6.35	4274.66	386.12	91.922	6	25	49200000	94.00	49200415	3.52	**188.0**
Changing CVN																
RBP	2	273.1	46	317.17	435	6.35	7136	386.12	153.452	2.5	25	20500000	46.38	20500000	2.01	**92.8**
RBP	2	273.1	46	317.17	435	6.35	7136	386.12	153.452	5	25	41000000	55.18	41000000	2.29	**110.4**
RBP	2	273.1	46	317.17	435	6.35	7136	386.12	153.452	7.5	25	61500000	59.02	61500000	2.41	**118.0**
RBP	2	273.1	46	317.17	435	6.35	7136	386.12	153.452	10	25	82000000	60.79	82000000	2.47	**121.6**
RBP	2	273.1	46	317.17	435	6.35	7136	386.12	153.452	12.5	25	102500000	61.59	102500000	2.50	**123.2**

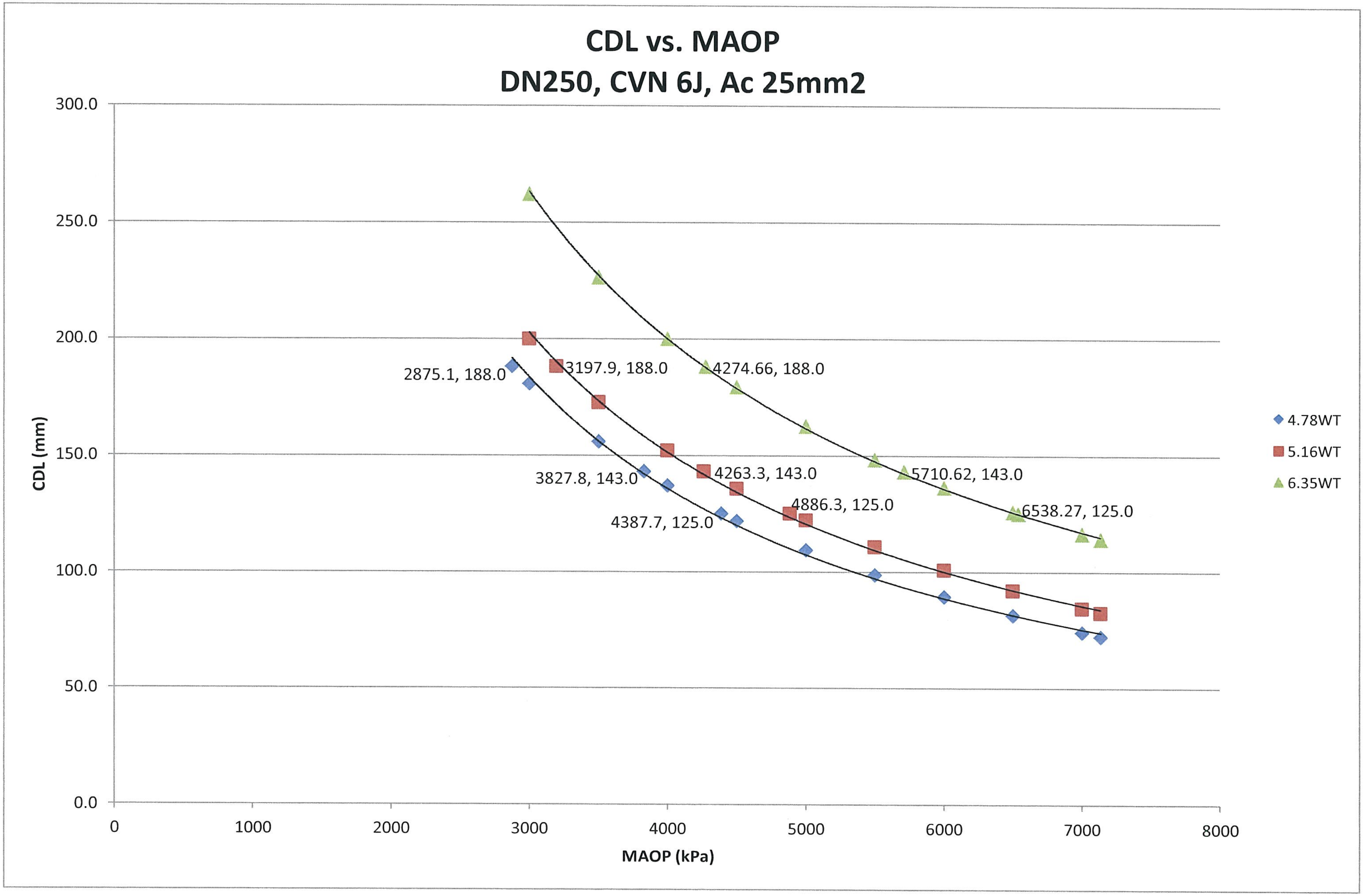
E (young's)	205000	Mpa

Notes

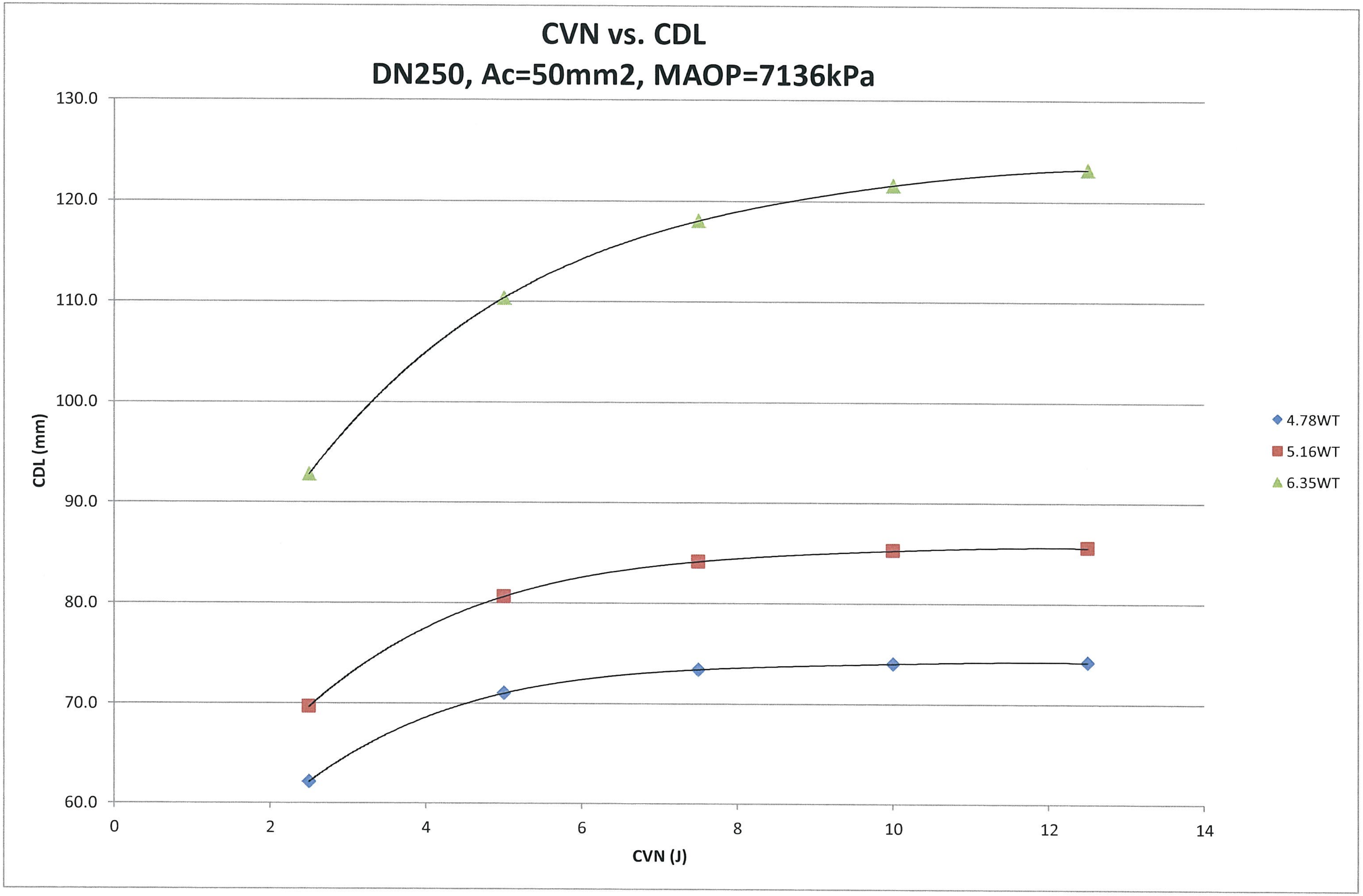
1. Critcal hoop stress, Flow stress and M factor equations are taken from AS2885.1:2012 Clause 4.8.5
2. MAOP hoop stress is calculated using Barlow's equation.
3. Both equations 4.8.5 (4) and (5) have been used, as to some extent CDL can depend on CVN. If CVN is unknown, recommend assuming 27J minimum.
4. Taken from Charpy Test Results on 1969 DN250 X46, 6.35WT

Calculated: C. Connor ______ *Signature* Date 30/09/2015

Checked: M. Jacobson ______ *Signature* Date 1/10/2015



CDL vs. MAOP
DN250, CVN 6J, Ac 25mm2
CDL (mm)
MAOP (kPa)
300.0
250.0
200.0
150.0
100.0
50.0
0.0
0
1000
2000
3000
4000
5000
6000
7000
8000
2875.1, 188.0
3197.9, 188.0
4274.66, 188.0
3827.8, 143.0
4263.3, 143.0
5710.62, 143.0
4886.3, 125.0
4387.7, 125.0
6538.27, 125.0
4.78WT
5.16WT
6.35WT



CVN vs. CDL
DN250, Ac=50mm2, MAOP=7136kPa
CDL (mm)
130.0
120.0
110.0
100.0
90.0
80.0
70.0
60.0
0
2
4
6
8
10
12
14
CVN (J)
4.78WT
5.16WT
6.35WT

CALCULATION SHEET

APA Group

320-CAL-AM-0116

Project Title	1969 DN300 MAOP Study - CDL	Project No	
Designed	Chris Connor	Date	30/09/2015
Checked	Martin Jacobson	Date	1/10/2015 Sheet_ 1 of 4
Approved	Francis Carroll	Date	1/10/2015

Critical Defect Length AS2885.1-2012 Section 4.8.5

The equations to determine the critical length of an axial through thickness flaw can be presented as follows:

Method 2 - For existing pipe, knowing toughness values (Low toughness steel)

For CDL of low toughness pipe with known Charpy V-notch Test energy (CVN, in Joules), and Fracture Area (Ac, in mm^2)

$$K_C^2 = \frac{8c(\sigma_{flow})^2}{\pi} \ln.\sec\left(\frac{\pi M_T \sigma_H}{2\sigma_{flow}}\right)$$

AS2885.1-2012 Eqn 4.8.5(4)

$$\frac{K_C^2}{E} = \frac{1000CVN}{A_C}$$

AS2885.1-2012 Eqn 4.8.5(5)

The above equations are simultaniously solved for "c", giving the CDL, where:

σ_{flow}	Flow stress = SMYS + 10 ksi for fracture control	MPa
K_C	In plane stress intensification factor (fracture initiation toughness)	$MPa/mm^{0.5}$
c	Half of the length of an axial through wall flaw	mm
M_T	Folias factor	

$$M_T = \left[1 + 1.255\frac{c^2}{\frac{D}{2}t_W} - 0.0135\frac{c^4}{\left(\frac{D}{2}\right)^2 (t_W)^2}\right]^{0.5}$$

σ_H	Hoop stress	MPa

$$\sigma_H = \frac{P_d D}{2t_W}$$

P_D	Design pressure	MPa
t_W	Wall thickness	mm
D	Nominal outside diameter = Pipe diameter = Pipeline diameter	mm
E	Young's modulus	MPa

Critical Defect Length Clause 4.8.5 AS 2885.1 - 2012

RBP DN300 5.16WT

Input

Goal seek

										CDL Method 2 Calculation (preferred for original RBP pipe) Low toughness steel CDL *[toughness dependent] - (note 3)*						
		Through Wall Defect														
Pipeline	License	Diameter (mm)	Grade (X_)	SMYS (MPa)	σ_U (MPa)	WT (mm)	Pd (kPa)	σ_{flow} (MPa)	σ_H (MPa)	CVN (J) (Note 4)	Ac (mm2) (Note 4)	Kc^2 - cl4.8.5 (5) (Mpa^2/mm)	c (mm)	Kc^2 - cl4.8.5 (4) (Mpa^2/mm)	Mt	**CDL (mm)**
Changing MAOP																
RBP	2	323.9	42	289.59	414	5.16	4612	358.54	144.76	10	25	82000000	59.17	82000000	2.45	**118.3**
RBP	2	323.9	42	289.59	414	5.16	4200	358.54	131.82	10	25	82000000	66.07	82000000	2.68	**132.1**
RBP	2	323.9	42	289.59	414	5.16	4000	358.54	125.55	10	25	82000000	69.87	82000000	2.81	**139.7**
RBP	2	323.9	42	289.59	414	5.16	3500	358.54	109.85	10	25	82000000	81.11	82000000	3.17	**162.2**
RBP	2	323.9	42	289.59	414	5.16	3000	358.54	94.16	10	25	82000000	95.89	82000000	3.63	**191.8**
RBP	2	323.9	42	289.59	414	5.16	2500	358.54	78.47	10	25	82000000	116.74	82000000	4.23	**233.5**
RBP	2	323.9	42	289.59	414	5.16	2000	358.54	62.78	10	25	82000000	150.83	82000000	5.02	**301.7**
RBP	2	323.9	42	289.59	414	5.16	1894.8	358.54	59.47	10	25	82000000	161.95	81971570	5.20	**323.9**
Changing CDL																
RBP	2	323.9	42	289.59	414	5.16	4404.8	358.54	138.246	10	25	82000000	62.50	82000119	2.56	**125.0**
RBP	2	323.9	42	289.59	414	5.16	3919.5	358.54	123.016	10	25	82000000	71.50	82000260	2.86	**143.0**
RBP	2	323.9	42	289.59	414	5.16	3056.1	358.54	95.918	10	25	82000000	94.00	82000089	3.57	**188.0**
Changing CVN																
RBP	2	323.9	42	289.59	414	5.16	4612	358.54	144.751	5	25	41000000	54.96	41000000	2.32	**109.9**
RBP	2	323.9	42	289.59	414	5.16	4612	358.54	144.751	6	25	49200000	56.52	49200000	2.37	**113.0**
RBP	2	323.9	42	289.59	414	5.16	4612	358.54	144.751	8	25	65600000	58.33	65600000	2.43	**116.7**
RBP	2	323.9	42	289.59	414	5.16	4612	358.54	144.751	10	25	82000000	59.18	82000000	2.45	**118.4**
RBP	2	323.9	42	289.59	414	5.16	4612	358.54	144.751	13	25	106600000	59.67	106600000	2.47	**119.3**

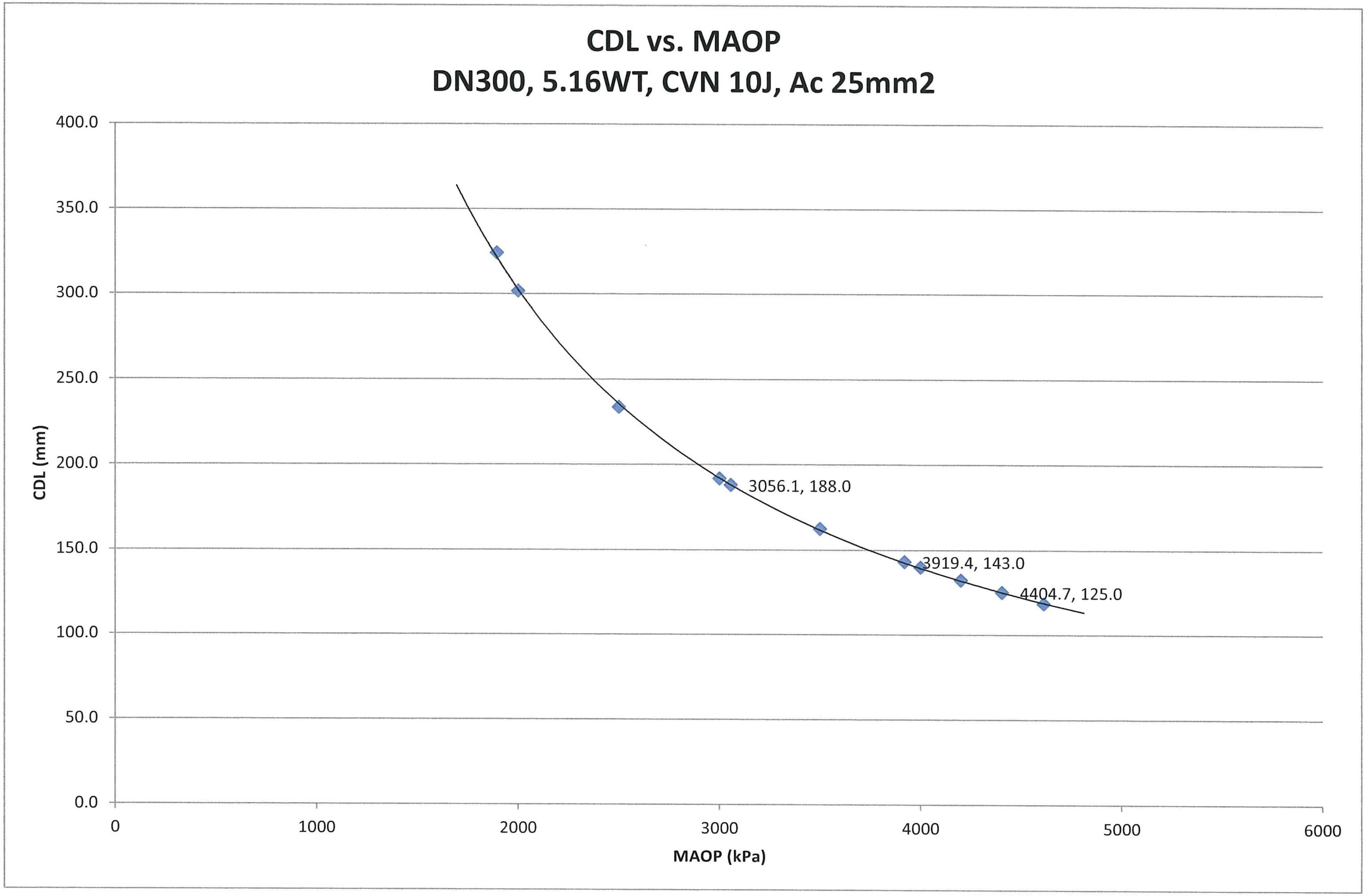
E (young's)	205000	Mpa

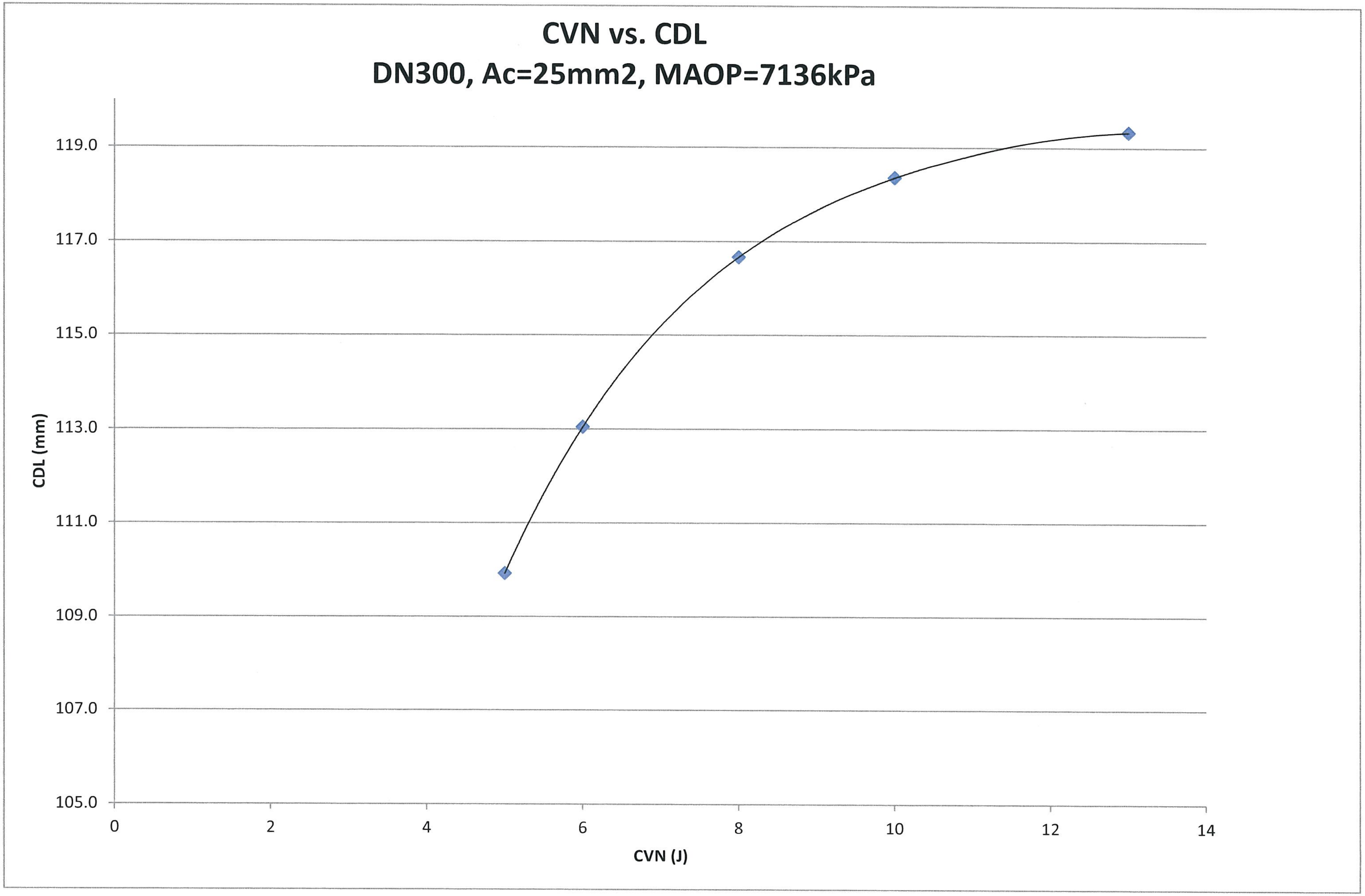
Notes

1. Critcal hoop stress, Flow stress and M factor equations are taken from AS2885.1:2012 Clause 4.8.5
2. MAOP hoop stress is calculated using Barlow's equation.
3. Both equations 4.8.5 (4) and (5) have been used, as to some extent CDL can depend on CVN. If CVN is unknown, recommend assuming 27J minimum.
4. Taken from Charpy Test Results on 1969 DN300 X42, 5.16WT

Calculated: C. Connor ______ *Signature* Date 30/09/2015

Checked: M. Jacobson ______ *Signature* Date 1/10/2015


CDL vs. MAOP
DN300, 5.16WT, CVN 10J, Ac 25mm2
CDL (mm)
400.0
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
0
1000
2000
3000
4000
5000
6000
MAOP (kPa)
3056.1, 188.0
3919.4, 143.0
4404.7, 125.0



CVN vs. CDL
DN300, Ac=25mm2, MAOP=7136kPa
CDL (mm)
119.0
117.0
115.0
113.0
111.0
109.0
107.0
105.0
0
2
4
6
8
10
12
14
CVN (J)

Appendix E

Risk Assessment Detail for Mitigation Option

ROMA BRISBANE PIPELINE ALARP STUDY
AS2885 RISK ASSESSMENT AND MITIGATION OPTIONS

		Current Status	With MOP Reduction to achieve No Rupture (e.g. 3000 kPa in Metro)	With Pipe Replacement	With Slab Protection	With Partial MOP Reduction (e.g. 4200 kPa in DN300 Metro) plus slab exposed areas
Description of Mitigation		RBP Pipeline Current Status (No additional mitigation)	MOP Reduced (>99% of the time) to achieve CDL of 1.5x max excavator defect, e.g. 3000 kPa for DN300 Metro	Pipe Replacement with modern 'no rupture' pipe; remove all non-compliant pipe from service	Concrete slab protection only, compliant with AS 2885.1-2012 clause 5.5.5 (ii). No change to pipe or MOP.	Reduce MOP to 4200 kPa or as low as practical while maintaining supply. Install slab protection at exposed locations e.g. road reserve, parkland.
Code Compliance		No Rupture - not met Energy Release - met in some scenarios	No rupture - met Energy Release - met for T1 only	No Rupture - Compliant all cases Leak Rate - Compliant all cases	No Rupture - not compliant Leak rate - not compliant	No Rupture - not met Leak rate - met for T1 only
20 tonne excavator	**Failure Description**	Other utility maintenance or construction, 10-20t excavator with tiger teeth in HCA. Leak with ignition, few Fatalities (both sensitive and T1)	Leak with ignition, few Fatalities (both sensitive and T1). Lower energy release due to MOP reduced.	No penetration. Coating damage or dent and gouge. Short term supply restriction.	Removes or avoids slab and penetrates pipeline wall. Leak with ignition, few Fatalities (both sensitive and T1)	Avoids slab, causes leak with ignition, few fatalities (both sensitive and T1).
	Consequence	Major	Major	Minor	Major	Major
	Likelihood	Remote	Remote	Remote	Hypothetical	Hypothetical
	Risk Level	Intermediate	Intermediate	Negligible	Low	Low
	Comments	Threat ID 192 2014 SMS Report. Refer LOPA 2 analysis.	No change for small excavator threat	Results in dent/gouge only, requiring short term restriction to supply. Leak or rupture not credible.	Slabbing effective, reduces likelihood to hypothetical or less (threat effectively controlled)	Slab protection reduces likelihood, consequence also lower due to MOP
35 tonne excavator	**Failure Description**	Major roadworks / construction, 35t excavator with tiger teeth in HCA. Rupture with ignition, multiple fatalities.	Penetration of pipe wall, results only in leak with ignition, few fatalities. Rupture non-credible.	Outcome is coating damage or at worst dent/gouge. Short term supply restriction only.	Removes or avoids slab and penetrates pipeline wall. Rupture with ignition, multiple fatalities (both sensitive and T1)	35t excavator with tiger teeth in HCA. Although not fully compliant with No Rupture (CDL < 1.5x credible defect), the likely failure is a leak with ignition.
	Consequence	Catastrophic	Major	Minor	Catastrophic	Major
	Likelihood	Hypothetical (High end 0.5x10^-6)	Hypothetical	Hypothetical	Hypothetical 10^-9 (2 orders of magnitude better)	Hypothetical
	Risk Level	Intermediate	Low	Negligible	Intermediate	Low
	Comments	Approx. 50% of DN300 accessible by 35T excavator & 90% of DN250 accessible by 35T excavator.	Large excavator rupture consequence is made non-credible by MOP reduction with >99% effectiveness.	Results in dent/gouge only, requiring short term restriction to supply. Leak or rupture not credible.	Slabbing effective, reduces likelihood to hypothetical or less (threat effectively controlled)	Likely consequence is a leak rather than rupture due to MOP reduction to 4.2 Mpa. Likelihood reduced by slab protection
Vertical auger (power pole)	**Failure Description**	Truck mounted pendulum auger replacing / installing power poles. 50 mm hole, leak with ignition	Auger still penetrates - slightly lower energy release due to MOP reduced.	Penetration still theoretically possible but thicker stronger pipe means likelihood is reduced.	Concrete slab effectively prevents auger from reaching pipeline	Concrete slab likely to prevent auger from reaching pipeline. Slightly reduced energy release rate.
	Consequence	Major	Major	Major	Major	Major
	Likelihood	Remote	Remote	Hypothetical	Hypothetical	Hypothetical
	Risk Level	Intermediate	Intermediate	Low	Low	Low
	Comments	Refer LOPA 1 and LOPA 4				
Horizontal drill / bore (telecom or power)	**Failure Description**	Small to medium HDD installing new power or telecoms cable in or across road reserve. Worst case a small leak (< 50 mm hole) with ignition	Similar failure consequence - slightly lower energy release due to MOP reduced.	Similar consequence - penetration still possible but thicker stronger pipe means less likely.	No change from current status.	No change from current likelihood - consequence slightly reduced by MOP reduction.
	Consequence	Major	Major	Major	Major	Major
	Likelihood	Hypothetical	Hypothetical	Hypothetical	Hypothetical	Hypothetical
	Risk Level	Low	Low	Low	Low	Low
	Comments	Based on APA experience HDD is expected to glance off pipeline. Refer to LOPA 3 and LOPA 5 in Metro SMS.		Reduced to low end of Hypothetical, bordering on non-credible	Side slabs are not currently proposed, top slabs have no effect on HDD threat	Side slabs are not currently proposed, top slabs have no effect on HDD threat

Appendix F

ALARP Questionnaire

Item	ALARP Question	APA Response for RBP (With MAOP/MOP reductions and slab protection)
(a)	Current level of safety risk (With proposed MAOP/MOP and slabbing)	
(i)	Are the potential consequences of this event particularly severe?	Yes – leak or rupture are possible in vintage pipe which can have a Major or Catastrophic consequence. However, catastrophic rupture event is made non-credible where MOP is reduced and likelihood significantly reduced to low end of Hypothetical when slab protection is provided.
(ii)	What is the level of safety risk to the public from the current arrangement from this threat?	Generally Intermediate (Major/Remote) for leak scenario with ignition. Rupture scenario is hypothetical to not credible.
(iii)	What is the level of safety risk to workers from the current arrangement from this threat?	Not applicable – pipeline staff are not expected to be present in an uncontrolled 3rd party impact scenario
(iv)	Does the risk change in the future?	No – further encroachment may change the extents of the high consequence areas but this will be managed accordingly.
(v)	If this is an existing facility, does it meet the standards that would be required for an equivalent new facility?	No. Modern pipelines would be designed such that excavator penetration is not credible.
(b)	Other drivers for further risk reduction (Beyond the proposed MAOP/MOP and slabbing)	
(vii)	Are there significant security of supply consequences for this event?	Yes – RBP metro area is the sole source of gas supply to Brisbane and SE QLD.
(viii)	Are there significant environmental consequences for this event?	No – natural gas release has limited environmental impact
(ix)	Are there significant reputational or other corporate reasons for wanting to reduce this risk further?	An incident in a populated area would have reputational consequences for APA however the MOP and slab protection is considered to be a sufficient risk reduction.
(x)	Are external stakeholders aware of and objecting to this risk?	DNRM (technical and safety regulator) supports APA's efforts to reduce public safety risk on the RBP however there is no significant external pressure at this stage.
(c)	What more could we do? (Beyond the MAOP/MOP and slab protection proposed)	

Item	ALARP Question	APA Response for RBP (With MAOP/MOP reductions and slab protection)
(i)	How might risk be reduced further? List as many ideas as possible then assess each one, starting with the one with the likely biggest risk benefit.	Refer to earlier sections of this report. The alternatives to increase risk beyond the proposed MOP and slabbing measures would be: 1) Replace all HCA pipe (not warranted due to disproportionate costs) 2) Install widespread slabbing in all HCAs in addition to MOP reductions (not warranted due to disproportionate costs) 3) Install slabbing at T2, S and identified higher-likelihood locations e.g. road crossings in addition to MOP reductions, to provide extra protection against leak consequence (recommended for consideration in ongoing slabbing programme) 4) Review effectiveness of third party liaison and use of drones in areas where patrols can't view the pipe (recommended for consideration by HEL)
(d)	Risk benefit of proposed measure (MAOP/MOP reductions and slabbing)	
(i)	What exactly is the proposed measure?	Reduce pipeline MOP downstream of Brightview in the DN250 pipeline 3300 kPa and the DN400 pipeline to 6300 kPa; and in the DN300 Metro to 3000 kPa except for Ellengrove to Eight Mile Plains which will be 4200 kPa or 3900 kPa. Install slab protection in all areas exposed to excavator/auger threats where MOP reduction is not sufficient to meet no rupture and energy release rate targets.
(ii)	What is the benefit in terms of safety risk to the public from the proposed measure?	Catastrophic rupture consequence becomes effectively not credible where MOP is implemented or slabbing is effected. All external interference threats become leak only (Major consequence) with greatly reduced likelihood where slab protection exists.
(iii)	Is the risk benefit 'real' or does this measure simply shift risk to another part of the system?	Benefit is real. Mitigation measures are applied at the locations of the high consequence areas and the excavator/auger/HDD threats.
(iv)	Is the proposed risk measure effective in all cases against this threat or it is designed to address only some cases?	Based on industry knowledge and experience, MOP reduction is effective in removing the rupture threat and slabbing is known to be effective against excavators and augers. The proposed measure has limited effect against HDD threats however the associated risk is already considered Low.

Item	ALARP Question	APA Response for RBP (With MAOP/MOP reductions and slab protection)
(v)	Is the proposed risk measure reliable in all cases against this threat i.e. will it work when called upon?	In conjunction with existing procedural controls (particularly daily ROW patrols) the slabbing and MOP reductions will effectively prevent external interference access to the pipelines by excavators and augers.
(vi)	Is the proposed risk measure available to be used in all cases when it might be called upon e.g. could it be affected by the threat itself?	MOP is always in place (except for contingency operations or pigging when additional procedural controls will be implemented). Slab protection could be removed by excavators but this process will take time and effort such that daily patrol would likely discover the work, and is expected to alert the operator to the presence of a pipeline.
(vii)	Is the proposed risk measure likely to be impacted by the same threat that it is designed to mitigate?	As above.
(viii)	Is the proposed risk measure a standard industry practice, or something novel?	Slab protection is a standard industry practice where land use around pipelines changes. MOP reductions are considered a step beyond standard practice due to potential commercial / revenue impacts in most pipelines.
(ix)	Is there a plan in place to monitor effectiveness etc?	Yes – APA monitors encroachments and near misses through the existing Land Management Plan and reports to the APGA POG Database.
(x)	Has this proposal been benchmarked against practices of others? If so, what do others think of this proposal?	This proposal is considered an industry leading approach for risk reduction on urban pipelines in Australia.
(xi)	Is the measure dependent on other things in order to function?	No. Budget provisions have been made for its implementation.
(xii)	Are there other tangible or intangible benefits of this measure?	The primary purpose of this proposal is to reduce the risks of external interference causing a pipeline failure in a built-up area. Other flow-on benefits are likely to be minor.
(xiii)	Are there risks associated with the proposed measure itself?	There are normal construction risks associated with installation of MLVs and PRSs on the live pipeline, and with construction of slabs above the pipeline however these are managed as part of the construction process.
(e)	Cost of proposed measure	
(i)	What is the cost of the proposed measure (capital and operating)?	Refer to Table 14 and preceding information.
(ii)	Is this proposed measure an industry standard approach to managing this threat?	Slab protection is a standard industry practice where land use around pipelines changes. MOP reductions are considered a step beyond standard

Item	ALARP Question	APA Response for RBP (With MAOP/MOP reductions and slab protection)
		practice due to potential commercial / revenue impacts.
(iii)	Is the proposed measure more expensive than it would be for a similar new pipeline?	Yes – retrofitting of MLVs, PRSs and slabs is significantly more expensive than when done at the time construction.
(iv)	Is the proposed measure justified on a pure cost/benefit analysis basis?	The benefit of risk reduction in high consequence areas is significant in terms of public safety and corporate reputation. There is no commercial benefit to APA as there is no additional revenue to be gained as a result of the capital works.
(e)	Uncertainty	
(i)	Do we understand the nature of the threat well?	Yes – excavator and auger threats to pipelines are reasonably well understood by the industry and continuing to develop.
(ii)	Is our risk assessment based on a comprehensive review of the history of this threat across the pipeline sector?	Yes – the SMS process considered historical and current knowledge of external interference threats across the industry and the specific regions of the RBP.
(iii)	Is the current and future land use / population well understood?	Yes – SMS process and APA's land management plan manage this.
(iv)	Is the environment around the pipeline at this location well controlled?	APA procedural measures include daily ROW patrols and awareness of threats by patrol personnel is high.
(v)	Is this scenario novel or a standard industry situation?	Standard industry situation however the nature of the RBP (location in road reserves in built up areas) means the extent of the threats is larger than usual.
(vi)	Are all industry standard methods of controlling this threat already in place?	Yes – refer SMS for existing physical and procedural controls. Some improvements are recommended to procedural controls.
(vii)	If we are subcontracting aspects of this situation, how certain are we that those involved have the necessary expertise and have in place the systems, processes and procedures to ensure the work is carried out as we intended?	Not applicable. Work will be carried out by APA and contractors under APA management.
(viii)	Is there evidence that existing risk controls for this threat are effective, available when needed, reliable, will survive in an accident?	Yes, refer (d) above
(ix)	Is there evidence that there are gaps in our knowledge about other risk	Not significantly. Some other controls are still subject to technology development but most are

Item	ALARP Question	APA Response for RBP (With MAOP/MOP reductions and slab protection)
	controls for this threat?	well understood.
(x)	Is there significant uncertainty associated with the effectiveness of the proposed measure?	No for MOP reduction and conventional slabbing. Trials are recommended to establish effectiveness of alternative slabs such as HDPE.

business case

pipeline integrity management upgrade

Business Case – Capital Expenditure

RBP Pipeline Integrity Management

Business Case Number AA-03 – REVISION 2

1 Project Approvals

TABLE 1: BUSINESS CASE – PROJECT APPROVALS

Prepared By	Francis Carroll, *Engineering Services Manager, APA Group*
Reviewed By	Craig Bonar, *Manager East Coast Grid Engineering, APA Group*
Approved By	Mark Fothergill, *General Manager Infrastructure Strategy and Engineering, APA Group*

2 Project Overview

TABLE 2: BUSINESS CASE – PROJECT OVERVIEW

Description of Issue/Project	The RBP 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. 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 its over-the-ditch tape coating system and its age that mean it requires significantly greater effort and expense in corrosion and integrity management that 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
Estimated Cost	$42.5 million over the AA period
Consistency with the National Gas Rules (NGR)	The pipeline integrity management work complies with the new capital expenditure criteria in Rule 79 of the NGR because: • it is necessary to maintain and improve the safety of services and maintain the integrity of services (Rules 79(2)(c)(i) and (ii)); and • it is such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services (Rule 79(1)(a)).
Stakeholder Engagement	Pipeline integrity management activities are an essential part of operating the RBP. DNRM, the Queensland technical regulator is a key stakeholder and their compliance programme includes assurance of RBP safety and integrity. Members of the public, APA staff and contractors working around the pipelines also expect APA to prudently manage the pipeline assets to minimize risks of failure and loss of containment. Shippers on the pipeline also expect APA to safely manage pipeline integrity.

3 Background

3.1 General

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 RBP has particular characteristics, such as its over-the-ditch-applied polyethylene tape coating system (on the original DN250, DN300 and DN200 pipelines) and its age, that mean 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.

APA has engaged the services of DNV GL, an international consultancy with global experience in pipeline integrity issues, to review this business case and the supporting documentation and to provide a review report commenting on the appropriateness and scale of the integrity management program for the RBP. The DNV GL report is available for review with this business case.

3.1.1 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 construction 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 the pipeline traverses many populated areas, and security of supply to customers. Significant portions of the RBP are located within residential areas in Brisbane and surrounding areas.

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 APA has 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, when the RBP was approaching 40 years in service, a design life review was conducted in accordance with AS 2885.3-2001. This review 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 a similar RLR is in progress on the DN250 section.

3.1.2 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. Risks associated with this coating type are splitting, cracking and UV degradation if exposed to sunlight for long periods. The DN400 RBP has tape coating and/or heat shrink sleeves on its field joints which means it is exposed to similar risks as the DN250 pipeline in the field joints. In APA's experience, pipelines from the 1980s such as early stages of the RBP DN400 also have some of the characteristics of 'vintage' pipelines.

Design lives for the DN400 looping stages were nominated as between 40 and 60 years in accordance with normal industry practice, at the time of design and construction of each looping stage. In 2012 APA undertook a MOP Upgrade of the DN400 system, raising its MOP from 8.0 MPa to a maximum of 9.6 MPa. As part of this process an integrity assessment, including inline inspection, was carried out and the pipeline is considered fit to operate at the new MOP. The next Remaining Life Review on the DN400 system will be completed in 2022 (10 years from the MOP Upgrade) in accordance with AS 2885.3-2012, or earlier if required based on ILI and engineering assessment.

3.1.3 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
- Deterioration of dents and gouges by a combination of the above factors with increased risk of fatigue cracking and SCC
- 1960s ERW seam welded pipes 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

Further background information is available in the Pipeline Integrity Management Plan (320-PL-AM-0027) and supporting reference documents.

3.1.4 Scope of Project

The integrity upgrade project comprises a number of different aspects:

- Inline inspection (ILI)
- Excavation, integrity works and new coating upgrades
- CP upgrades

3.2 Code and Regulatory Requirements

Integrity management of pipelines is a core requirement of AS 2885.3 and of the Queensland Petroleum and Gas (Production and Safety) Act and Regulation. APA as the pipeline licencee has an obligation to carry out integrity management activities under the requirements of the Pipeline Management System and the Pipeline Integrity Management Plan. Sections 5, 6 and 9 of AS 2885.3-2012 set out the specific requirements.

The key objectives of the legislation and the Australian Standard is to ensure that pipelines are safely constructed, operated and maintained, and that risks of harm to people and to the environment and security of supply are managed to an acceptable level. Pipeline integrity management is critical to achieving these objectives by reducing the risk of pipeline failure and loss of containment.

3.3 Inline Inspection

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.

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. However, most pipelines covered by the APA national policy are to a standard that permits a 10 year interval.

The RBP is designated in the Queensland Petroleum and Gas (Production and Safety) Regulation 2004 as a 'Strategic Pipeline' (refer Schedule 5 of the Regulation). Under this legislation, in section 80, all pipeline segments comprising 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, as a minimum requirement.

There have been improvements in ILI technology over the life of the RBP such that APTPPL is nowable to identify dents and metal loss that were not detected in previous ILI runs. Other technologies have also been developed to enable inline inspection for cracking and for pipeline strain, which are relevant to the threat of stress corrosion cracking. Further ILI technology developments are ongoing and likely to become commercially available during the next AA period.

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 is 5 years for the DN250 and DN300 pipelines, with unsustainable numbers of repairs predicted if re-inspection intervals are extended beyond 5 years.

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.

ILI on the RBP takes a number of different forms:

- High-resolution magnetic flux leakage (MFL) inspection – detects corrosion, gouges, grooves, mill defects, girth weld anomalies and other metal loss features
- Geometry or caliper 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
- XZY (3-dimensional) inertial mapping – Maps the geographical position of the pipeline centreline and records any movement or change in shape since previous inspection. XYZ pigging enables curvature and strain analysis which is a key factor in mitigation of circumferential stress corrosion cracking.
- Electro-Magnetic AcousticTransducer (EMAT) inspection – recently developed technology that detects cracking and crack-like features. EMAT is used in the RBP to detect and manage stress corrosion cracking and longitudinal weld anomalies.

In 2014-15 APTPPL undertook MFL, geometry and XYZ ILI of the the DN250 (7 sections). Analysis of this combined with the results of the 2011 ILI of Metro DN300 identified a large number of previously unreported dents and a very large number of metal loss features, primarily external corrosion, which has led to the increased scale of integrity excavation and coating upgrade programme.

It was identified by APA that dents are high risk of cracking or gouging and are the most likely defects to lead to pipeline failure. Dents were prioritized based on reported depth and length, o'clock position, seam weld/ girth weld association, metal loss association, multiple dents in close proximity, plus risk prioritization based on location and proximity to populated locations. 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.

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

Due to the increasing volume of pipelines and integrity data to be managed, APA invested in a software system known as Integrity Data Management Tool (IDMT) for the RBP between FY12 and FY14. This software has a geospatial database and manages ILI and repair data to assist in prioritisation of inspection and upgrade works.

3.4 Excavation and integrity upgrade programme

3.4.1 Anomaly Assessment and Defect Repair Process

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

A typical integrity upgrade dig includes:

- Locating the pipeline, ILI anomalies and nearby girth welds (for location reference purposes) by surveying and potholing
- Excavating a trench around the pipeline for safe access and to expose the pipeline for assessment and repair
- Removal of old and deteriorated coating from the pipe surface and abrasive blasting to prepare the surface for inspection
- Assessment of the ILI anomalies by visual, physical and non destructive testing, and engineering assessment of the results to determine repair requirements
- 100% surface inspection for crack detection, using magnetic particle inspection or eddy current array inspection
- Pipeline refurbishment as required, to restore strength and upgrade the lifetime (e.g. fibre composite or steel sleeve)
- Application of modern high-build epoxy coating to extend pipeline life, improve CP performance and prevent further corrosion or cracking
- Reinstatement of the earth fill around the pipeline and reinstatement of environmental and surface treatment

Where girth weld or seam weld anomalies are identified by the ILI or the site inspection, these are assessed by appropriate methods including ultrasonic or radiographic inspection and repaired as required.

3.4.2 Past excavations and coating upgrades

Historically, APA had completed excavation and recoating works in two streams – one based on ILI results addressing mainly metal loss anomalies, and a second stream based on CIPS. Close interval potential surveys (CIPS) were carried out on selected sections of the RBP where CP was known to be less effective. During the 2012-2017 AA period, APA excavated and applied new coating on around 400 metres of the DN250 RBP, selected on the basis of the CIPS. Selected locations were where CP levels were known to be poor, such as near the Wallumbilla where in the past, gas temperatures routinely exceed the coating limitations due to no cooling of the gas after compression to transmission pressure at Wallumbilla.

Following the ILI surveys in 2014-16, the requirement for pipeline excavation and coating repairs increased significantly. As described above, these ILI surveys identified a large number of previously unreported dents and metal loss anomalies. APA made a decision at this time to target the integrity and coating upgrades at areas of metal loss and pipeline deterioration as identified by ILI, and to discontinue the routine use of CIPS for upgrade targeting.

The 2014-15 and 2011 MFL ILI results strongly pointed to a deterioration in the health of the pipeline so APTPPL increased its excavations and integrity upgrades. In FY15 APTPPL undertook ~35 excavations including ILI verification. In FY16 APTPPL undertook ~75 excavations.

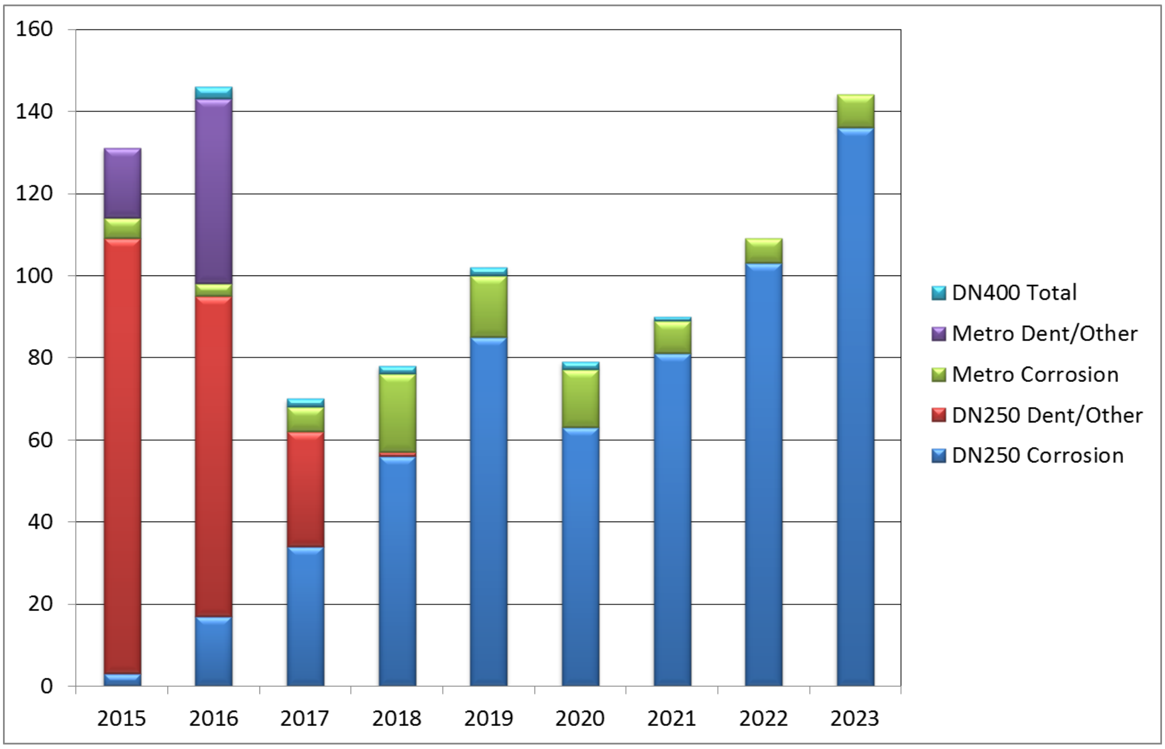
In FY15 and FY16 the integrity upgrade programme was primarily addressing dents and metal loss features which may cause restrictions in maximum operating pressure, as these represent a more present risk to the integrity and safety of the pipeline.

3.4.3 Forecast Look-Ahead

Based on the past ILI results and experience during the excavations, APA is projecting similar number of excavations on the RBP in future years. APA has in fact prioritized the proposed excavation numbers in FY15 and

16 based on risk, to defer some of the work to prudently manage the expenditure. This results in a program of typically 100+ excavations per year.

The following chart shows the outcomes of the pipeline integrity modelling showing the number of excavations and repairs required in each calendar year, based on corrosion growth modelling in accordance with AS 2885.3-2012 and the relevant referenced standards.



Actual digs have been prioritized and scheduled according to risk levels, and sorted into financial-year dig campaigns in FY15 and FY16. As a result of the large number of previously unreported anomalies, some excavations and repairs, which were recommended for repair in 2015 and 2016, will carry over into 2017 and 2018. MOP restrictions are being implemented on the DN250 and Metro pipelines where required to manage any unrepaired anomalies.

It should be noted that the above graph is based on a reinspection of the DN250 pipeline in 2019, which is likely to reduce the excavation requirements in 2020. If reinspection is not done, the required number of digs continues to increase exponentially.

Also, the features have been grouped where they are close together. One excavation and repair in the above graph may incorporate many features if they are within the same pipe spool.

The table below sets out the forecast number of excavations and upgrades for the next 6 financial years, including balancing of work between financial year periods..

Year	FY17	FY18	FY19	FY20	FY21	FY22
Metro #	27	33	36	15	11	7
Non-Metro	81	83	94	76	74	93
Total	108	115	130	91	85	100
Cost	$4,913,000	$5,293,000	$5,971,000	$3,983,000	$3,677,000	$4,231,000

Future years of excavation and upgrade works are expected to focus more on metal loss areas as corrosion growth continues. As APTPPL continues its inspection programme for stress corrosion cracking (SCC) the integrity upgrade program will include any identified SCC defect repairs as part of the new coating and CP upgrades where efficient to do so.

As a result of the different design the RBP DN400 and most laterals,the digup and integrity upgrade programs for these pipelines, including verification digs for ILI and isolated defect repairs, are typically much smaller scale.

The integrity upgrade programme also includes SCC direct assessment as per section 3.6 and selected coating upgrade areas for CP interference / mitigation as required.

3.4.4 Delivery of Integrity Upgrade Programme

APA has the experience and capability to deliver the necessary integrity upgrade program of works. Over the past two years the work has transitioned from ad hoc excavations and repairs by operations personnel, to a major project ‘campaign’ approach using APA’s in house construction and project management team. This is expected to improve efficiency and reduce costs over the long term.

APA has brought experience in pipeline integrity upgrades to this work using lessons learned and management approaches from the Moomba-Wilton gas pipeline repair programme, which typically undertakes several hundred excavations and repairs per year.

3.5 Cathodic Protection Upgrade Programme

An aging pipeline and ongoing coating deterioration requires significant investment in cathodic protection (CP) upgrades. Cathodic protection is a method of preventing corrosion of buried or submerged pipelines by applying a DC electrical current. The current is applied using an external power source and anode, which forces the entire pipeline surface to become the cathode in an electrochemical cell and therefore prevents corrosion. Application of CP is a proven technology and a standard requirement for buried hydrocarbon pipelines. AS 2885.1 and AS 2832.1 are the relevant standards.

Because of the coating type and codition, all CP systems on RBP are under heavy load due to the high current demand, particularly on the DN250 pipeline. Currently, the DN250 and DN400 RBP lines are cross-bonded at many locations to improve distribution of CP current consistent with the CP Plan.

Continual upgrade of CP systems is required including an increase in current output capacity of systems (new TR units and anode beds, new land easements to locate anodes further from pipeline), and the installation of new CP systems to infill low protection areas between existing systems. This is because the increased exposed steel surface area requires additional CP current. Further, the increased current demand causes more rapid attenuation of protection potentials along the pipeline away from CP units.

There are 69 CP units currently on the RBP. All are impressed current current CP systems typically between 20-80 Amps output. Total CP current for the RBP is over 1500 A. The typical anode bed life is 10-15 years meaning that on average 5 or so anode beds per year require replacement.

Linear anodes and other emerging technologies for CP have been considered by APA but have not been sufficiently economical compared to convential remote anode CP to date. Where required in future, linear anodes or deep well anodes may be employed.

Due to increasing requirements and technology changes, the anode beds when upgraded often need to be physically larger and also need to be located further away from the pipeline to improve CP current distribution, meaning that additional land is required. Land requirements include easements and new or improved landholder agreements.

As the coating condition is poor, RBP corrosion protection relies heavily on CP. Awareness and repair of CP outages is vital and currently relies on field staff travelling the pipeline right of way fortnightly to check CP units. Remote telemetry brings the CP unit data (output voltage and current, pipe potential where available) back to SCADA enabling APA control room and engineering staff to see trends live and raise corrective work orders for field staff if power is lost or a CP unit fails. This removes the risk of unit/s being offline for weeks or months depending on field scheduling, ROW access, weather etc. This brings the RBP into line with current industry practice for pipeline CP monitoring.

3.6 Stress Corrosion Cracking

Stress corrosion cracking (SCC) is a failure mechanism for pipelines where in the right conditions of pipeline material, external soil / coating environment, and sufficient tensile stress, cracks can develop and grow over time in the pipe wall. There are two different mechanisms, high-pH and near-neutral-pH SCC.

The RBP, especially the DN250, meets the criteria for susceptibility to near-neutral pH SCC. These criteria include the age of the pipeline, steel metallurgy of the time, lack of abrasive blasting of the pipe surface before coating, use of the PE tape coating system, and potential shielding of CP by disbonded tape coating. Environmental factors for near-neutral pH SCC include soil type, pH and moisture level as well as ground movement or steep slopes. More detail on the SCC mechanisms is set out in the SCC Management Plan (320-PL-AM-0031).

AS 2885.3 requires APA to manage threats to the pipeline's integrity, including SCC. APA has developed a Stress Corrosion Cracking Expert Guide which informs the management of SCC throughout any susceptible pipelines. To meet the requirements of the standard and the Expert Guide, APA has developed a SCC management plan specific for the RBP, with reference to international standards including the CEPA guideline Stress Corrosion Cracking – Recommended Practices and the NACE International SCC Direct Assessment standard.

Near-neutral pH SCC can include both axial and circumferential cracking. Both types of cracks, to differing severities, have been found in RBP. Significant axial SCC has only been detected in areas of high pipeline strain to date.

As the name suggests a circumferential crack is one oriented circumferentially around the pipe. The RBP has had three leaks resulting from circumferential cracks in the pipe body – 1983, 2011, and 2014. The exact nature of this failure mechanism was not fully understood until 2014 as it is an unusual failure mechanism, related to areas of high curvature and bending strain over a period of time. Strain features were subsequently included in the RBP excavation and life extension programme. One inspection of a strain feature resulted in a cutout due to circumferential cracking that had not yet penetrated the pipe wall but was unacceptable to remain in the pipe. The most likely outcome of severe circumferential cracking is a leak. APA has developed screening criteria for pipeline strain magnitude to identify locations at risk of circumferential cracking.

An axial crack travels along and depth-wise through the pipe. Axial cracks provide the highest risk of rupture particularly if their length exceeds the critical defect length for the pipeline. Both leaks and ruptures could occur anywhere in the pipeline as internal pressure provides a significant tensile force. CEPA guidelines apply and this threat is considered in the SCC expert guide. Axial cracking is also affected by general stress and strain state in the pipeline, and axial cracks can also be induced by external loads, e.g. where ovalisation of the pipe occurs.

In order to check for the axial cracking failure mechanism, crack detection ILI is proposed for all of RBP DN250 and DN300 in the SCC Management Plan. The DN300 Metro line was inspected with an EMAT tool in 2016. Similar EMAT inspection is planned for all DN250 segments once a DN250 tool is developed by the vendor. The alternative ILI method is ultrasonic testing - while this is a proven technology for crack detection, is not feasible for gas pipelines without inserting a large liquid slug which is not practical in the RBP without major impacts to distribution network customers and would not be practical with the large elevation changes. The EMAT ILI also has the capability to detect longitudinal seam weld anomalies, which are known to occur in vintage ERW line pipe.

APTPPL is undertaking SCC direct assessment at all digs; this involves 100% coating removal and crack detection by magnetic particle inspection or eddy current array, which increases dig cost and duration compared to standard ILI verification digs. The coating upgrade at digs include abrasive blasting of surface and liquid applied epoxy coating in accordance with APA's current engineering standards.

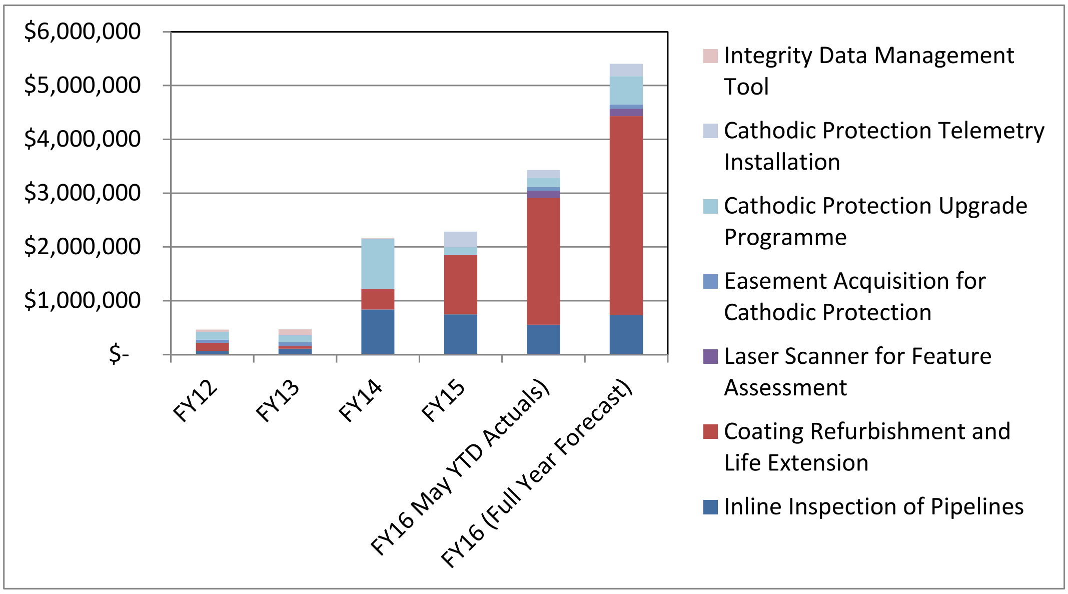
Where SCC is identified, ultrasonic inspection is carried out to estimate the crack depth and length and any sub-surface continuation of cracking. Fine and shallow cracking (typically less than 10% of wall thickness in depth) may be removed by buffing or grinding. Fitness for service assessment is conducted on any remaining cracking. Loss of containment cracks such as the three historic leaks, or severe cracking failing FFS assessment, is generally removed from the pipeline either by depressurisation, purging, cutout and pipe replacement, or by in-service hot tapping to remove the defect area.

4 Historical Capital Expenditure

The table below provides actual capex over the current AA period for projects related to pipeline integrity management.

Project / Programme	FY12	FY13	FY14	FY15	FY16 (May YTD Actuals)	FY16 (Full Year Forecast)
Inline Inspection of Pipelines	$ 66,675	$ 106,612	$ 836,871	$ 746,612	$ 553,289	$ 730,000
Coating Upgrade and Life Extension	$ 154,406	$ 48,159	$ 379,295	$ 1,102,101	$ 2,354,749	$ 3,700,000
Easement Acquisition for CP	$ 54,304	$ 71,954	$ 4,679	$ 612	$ 67,956	$ 75,000
Laser Scanner for Feature Assessment	$ -	$ -	$ -	$ -	$ 139,009	$ 140,000
CP Upgrade Programme	$ 143,912	$ 140,503	$ 932,192	$ 145,807	$ 173,381	$ 527,000
CP Telemetry Installation	$ -	$ -	$ -	$ 287,637	$ 139,990	$ 230,000
Integrity Data Management Tool	$ 43,318	$ 99,352	$ 17,177	$ -	$ -	$ -
Total Capex - Integrity Management	$ 462,615	$ 466,579	$ 2,170,213	$ 2,282,769	$ 3,428,373	$ 5,402,000

The capex spend profile is plotted below.



4.1 Comments on Historical Capex

Comments are provided on the historical expenditure as follows.

4.1.1 Inline Inspection

ILI is traditionally a 'lumpy' spend with substantial costs at long intervals. Across there RBP there have been a number of ILI campaigns in the period:

- FY13-FY15 - DN250 RBP x 7 sections MFL/Geometry/XYZ pigging
- This was interrupted in June 2014 by Toowoomba Range DN250 pipeline incident, resulting in significant carry over of the DN250 ILI into FY15
- FY16 - ILI costs mainly reflect the DN300 Metro pipeline EMAT ILI (crack detection as part of SCC management
- The DN300 EMAT tool became newly available to industry (previously only larger sizes) and APA elected to run the tool in the RBP Metro due to its designation as a high consequence pipeline
- The ILI costs include verification excavations and site inspections conducted as part of the ILI campaign

4.1.2 Coating Refurbishment / Excavation and Integrity Upgrade

- FY12-FY14 costs were for new coating application, targeted on areas of low CP, high current demand, identified by CIPS
- FY15 costs reflect the first round of identified metal loss and dents and strain features from the 2014 DN250 ILI
- As a result of the large number of ILI features and some of the field results in DN250 an expanded programme was developed for FY16 to encompass dents (high risk for cracking) and metal loss. This expanded programme included reprioritised DN300 Metro dents and metal loss features.

CP Upgrades

- There has been an ongoing upward trend in costs due to increasing CP current demand (new systems, replacement anode beds, larger TR units) as discussed elsewhere in the business case
- FY14 large spend – the initially planned FY14 spend was $450k. However, it was identified that it was more efficient to bring forward the materials purchases for FY15 hence increased spend that year to $900k+; this reduced the costs in FY15 to just installation of the prepurchased materials
- Likely costs going forward similar scale to that planned for FY14 as set out in the proposed works section of this business case

4.2 Problem/Opportunity Statement

This project is a proposed continuation of works to improve the safety and integrity of the RBP buried pipelines. The works address ongoing corrosion and deterioration of the buried pipelines associated with their age, construction methods, coating degradation and other time-dependent threats to the pipelines.

If not addressed, this problem would affect all users of the pipeline as the outcomes would be pressure restrictions, loss of supply, shutdown of pipeline sections and eventual pipeline failure by leak or rupture, potentially with significant safety consequences. The upgrades will also slow the rate of growth in pipeline deterioration. This will be expected to reduce the number of urgent repairs required on the pipeline compared to what otherwise would have been the case.

A successful solution will result in pipelines that are safe and fit for purpose and able to be operated in accordance with the relevant legislation and standards without endangering the public or APTPPL employees.

4.3 Timing of the Issue

With any buried pipeline, the issues of pipeline integrity management commence as soon as the pipe is laid. The proposed work is a continuation of the ongoing integrity management activities that have been in progress for decades.

As described in the historical capex review above, work has been ongoing on this issue for some time. It will continue for the life of the assets, or until the pipelines are decommissioned.

Due to the age of the asset and more sophisticated assessment the expenditure of on integrity improvements has been increasing in recent years and are expected to continue at this new level for the duration of the access arrangement. This is expected to reduce the need for significantly more expensive interventions in emergency situations in the future.

4.4 Standards and Legislation

The following standards and legislation apply to the integrity management of the RBP:

- Queensland Petroleum & Gas (Production and Safety) Act and Regulation 2004
- Australian Standard AS 2885.3
- RBP Pipeline Licence #2

The legislation and code requirements are for APA as the Licencee to maintain and operate the pipeline in accordance with AS 2885.3, which includes pipeline structural integrity management, corrosion protection and monitoring, and pipe wall integrity requirements in Section 6.

Further to the AS 2885.3 requirements, the Queensland legislation designates the RBP as a 'strategic pipeline' and specifies mandatory ILI maximum intervals. All RBP pipeline sections require ILI to be completed within 7 years of commissioning, and at least once in every 10-year period following the initial 7 years.

5 Risk Assessment

Risks associated with natural gas transmission pipeline integrity include significant safety hazards. Potential outcomes if integrity management works are not carried out include leak (e.g. from corrosion) or rupture (e.g. from SCC or large corrosion defect) releasing a large inventory of flammable gas, with possible ignition and catastrophic consequences up to and including fatalities to workers and members of the public within the measurement length.

Depending on the location of any such failure, a leak or rupture of the RBP could also have serious operational / customers / reputation and financial impacts to APA. Since the pipeline is the sole source of natural gas to south-east Queensland, loss of containment in certain locations could lead to curtailment or failure of gas supply to significant distribution networks to homes and businesses, as well as large industrial users.

Pipeline integrity risks are managed in APA through the AS 2885 SMS process. The SMS assesses risk levels with existing controls and the relevant SMS records to pipeline integrity management are summarized in Table 3. Details from the SMS database for these relevant existing threats are available in the attachments to the Business Case.

The existing risk rankings in the RBP SMS are listed in Table 3 along with the theoretical risk levels that would apply if the integrity management programme was discontinued. The worst-case risk rankings are generally associated with risk to personnel and public, i.e. injuries and fatalities resulting from a leak or rupture with ignition. Loss of supply risks are also significant in some cases.

TABLE 3: RISK RATING (AS 2885 SMS EXTRACT)

Threat	Risk Level (Existing APA AS 2885 SMS)	Assessed Risk Without Integrity Management (AS 2885)
External corrosion	Low (Remote/Severe)	Intermediate (Unlikely/Severe)
Internal corrosion	Failure not credible	Failure not credible
Stray current corrosion (railway etc)	Failure not credible	Low (Remote/Severe)
Stress corrosion cracking - Axial	Intermediate and ALARP (Catastrophic/Hypothetical)	High (Catastrophic/Unlikely)
Circumferential cracking in DN250 and DN300 pipelines (1969) due to strain on pipe	Low (Remote/Severe)	High (Catastrophic/Remote)
Dents combined with metal loss or located on welds	Low (Hypothetical/Major)	High (Unlikely/Major)

6 Options Considered

6.1 Option 1 – Do Nothing

Under this option APTPPL would cease to undertake the suite of integrity management on the pipeline and would drop back to a minor level of integrity activities. This would be consistent with a modern pipeline but would not meet the safety and integrity requirements of the RBP. It would entail reduced ILI frequencies; greatly reduced excavation, coating upgrade and life extension works, and reduced CP upgrades.

6.1.1 Cost/Benefit Analysis

This option would result in a deterioration of the pipeline, increases in the cost of CP and costs and risks associated with pipeline failure. It would fail to provide the basic integrity requirements of the RBP and would reflect a failure of APA's systems. The safety management study would identify a significantly increased risk level including risks ranked as High under the AS 2885 framework, which is unacceptable to continue operation of the pipeline under the standard.

This would result in APA breaching its obligations under AS 2885 and the P&G Act. Pipeline CP would rapidly deteriorate and the likely outcome would be pipeline failure/s, potentially with catastrophic consequences. At the more extreme level even in the absence of a demonstrated pipeline failure APTPPL may still be directed to cease operation of the pipeline due to the unacceptable risk posed to the public.

The reduction in pipeline integrity would lead to an increase in the indirect costs and risks of responding to failures, including:

- more expensive and intrusive repairs e.g. cut out of failed pipeline section rather than recoating or strengthening in situ; and
- Likely regulatory penalties, civil damages, reputational and customer losses, gas losses and risk of injury and death for the public and employees.

6.2 Option 2 – Continue Integrity Management and Upgrade Program

This option involves the continuation of the IM programme on the existing RBP assets as per the proposed actions set out in the Business Case sections above. Details of the proposed integrity management and upgrade program are set out below.

6.2.1 Inline Inspection

APA would propose to continue the ILI program at intervals as required by the PIMP and set out in the ILI master schedule.

Upcoming ILI within the AA period includes:

- DN300 Metro MFL FY17 (last done 2011 – 5 yr interval)
- DN400 Ellengrove MFL FY20 – 10 year schedule
- DN200 Lytton MFL FY18 – 7 year legislative requirement (Strategic)
- DN400 RBP MFL FY21 – 10 year interval
- DN250 RBP MFL FY19 – 5 year interval
- DN400 Metro Loop 1 – FY19 7 year legislative first inspection
- DN200 Gibson Island FY19 – 7 year interval
- DN250 RBP EMAT SCC FY19 and FY20 – subject to DN250 size EMAT tool becoming available
- DN250 Peat Lateral – FY20 – 10 year interval

The ILI inspection intervals are set by the PIMP and are in line with APA's corporate ILI policies and Queensland legislation.

6.2.2 Excavation and Integrity Upgrades

Under this option, APA would continue the prioritised excavation, repair and recoating works as set out in the forecast in section 3.4.3. The dig program would continue to address dents (prioritised where dents are associated with metal loss, seam weld or girth weld), pipeline strain events, and metal loss indications.

6.2.3 Cathodic Protection Upgrades

This option includes continuation of the CP upgrade program, including CP systems, anode beds, TR units, as well as telemetry units to provide SCADA monitoring and land tenure works to obtain easements for new and existing anode beds where required.

6.2.4 Cost/Benefit Analysis

Benefits of this option are:

- Compliance with statutory obligations and AS 2885
- Mitigation of risk of pipeline failure to acceptable levels
- Extension of asset lifetimes and deferral of eventual replacement costs
- Avoid regulatory fines, civil damages, reputational and customer losses

Costs for the proposed programme are detailed in the cost breakdown in section 6.5.4.

6.3 Option 3 – Replace Pipelines

Another option is to replace sections of the pipeline at the point that its integrity begins to deteriorate through dents or metal loss. In this scenario, no ILI would be done to establish the condition of the pipelines and therefore all sections would be replaced on an age basis.

The highest priority for pipe replacement would be DN300 Metro and DN250 pipeline due to age 47 years and condition (these are where the majority of CP, ILI and upgrade costs are going). DN400 Wallumbilla to Moggill would also need to be replaced within AA period as sections are approaching 30 years old.

This option was considered in the SMS for the Intermediate threat of axial stress corrosion cracking as part of the ALARP analysis, but was not selected in comparison to the integrity management due to the very high costs.

6.3.1 Cost/Benefit Analysis

This option is not a realistic alternative to the preferred option due to the high capital cost of pipeline replacement. A high level estimate, based on the actual cost of metro looping and recent APA experience on other pipelines, would cost the replacement of the DN250 and DN300 pipelines at approximately $920m. While there would be some minor opex savings resulting from the newer pipeline and some capex work would be delayed they would be insufficient to offset the significant upfront cost.

6.4 Summary of Cost/Benefit Analysis

The section should include a general overview of how the options compare and identify any options are not technically feasible.

TABLE 4: SUMMARY OF COST/BENEFIT ANALYSIS

Option	Benefits (Risk Reduction)	Direct Costs	Commentary
Option 1	Do nothing - Minimal integrity management SMS risk = High	0 (additional to normal O&M costs)	Significant risk of early pipeline failure
Option 2	Integrity management and upgrade programme SMS risk = Low to Intermediate / ALARP	$42.5M	This option is the minimum required works to maintain safety and integrity of existing assets
Option 3	Replace Pipelines SMS risk = Low	$920M+	Replace DN250 and DN300 immediately; Others likely during the AA period as well

6.5 Proposed Solution

6.5.1 What is the Proposed Solution?

Option 2 – Continue integrity upgrade programme to manage the safety and integrity of the existing assets

6.5.2 Why are we proposing this solution?

Integrity management activities are a mandatory requirement of AS 2885.3 and the QLD Petroleum & Gas Act. Doing nothing in relation to integrity management would breach our legal obligations and appropriate standards.

Option 2 is also the most efficient means of ensuring the ongoing safety and integrity of the pipeline. Continuing to undertake this in a manner adopted prior to this program would result in higher long term costs as a result of inefficiently targeting the areas of need and not undertaking a sufficient rollout of new coating and upgraded CP resulting in a deterioration in the long term integrity of the RBP.

The option of replacing the pipeline while also effective at achieving an outcome consistent with AS2885 it would cost more than 20 times the cost of the preferred option.

6.5.3 Consistency with the National Gas Rules

6.5.3.1 Rule 79(2)

The capex is consistent with rule 79(2) of the National Gas Rules as it is necessary in order to maintain and improve the safety of services (r79(2)(c)(i)) and it is necessary in order to maintain the integrity of services (r79(2)(c)(ii)). The RBP is aging and is being affected by corrosion and dents. As these corrosion and dents are precursors for pipeline failure it is necessary that they be identified and resolved. Pipeline failure would result in suddent loss of pressure and an inability to continue to provide pipeline services until the issue has been resolved. Further, a sudden pipeline failure is potentially fatal to anyone in the area of impact in addition to the health risks associated with a loss of containment of the natural gas. Therefore, the expenditure is necessary to maintain the safety and integrity of pipeline services.

6.5.3.1.1 Rule 79(1)

Rule 79(1)(a) states:

> *the capital expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services*

This capital expenditure is consistent with rule 79 as it is:

- *Prudent* – In the absence of this expenditure the RBP would reach a point where it could no longer continue to operate. As APTPPL would be directed for safety reasons to cease to operate the pipeline.
- *Efficient* – The option selected is the most cost effective long term option that meets the necessary operational requirements in order remain compliant with legal obligations and Australian standards. The work was identified and considered under APA's expenditure framework *and was and will* continue to be undertaken in accordance with APA's procurement policies.
- *Consistent with accepted and good industry practice* – Addressing the risks associated with the corrosion and metal loss is accepted as good industry practice. In addition the reduction of risk to as low as reasonably practicable in a manner that balances cost and risk is consistent with Australian Standard AS2885.
- *To achieve the lowest sustainable cost of delivering pipeline services –*

6.5.4 Forecast Cost Breakdown

The below table provides a summary of the integrity management capex project cost forecasts as set out in the asset managment plan.

Project / Programme	FY17	FY18	FY19	FY20	FY21	FY22	AA TOTAL
Inline Inspection of Pipelines	$ 225,000	$ 2,000,000	$ 2,830,000	$ 330,000	$ 1,800,000	$ 1,120,000	$8,305,000
Coating Refurbishment and Life Extension	$ 4,913,000	$ 5,293,000	$ 5,971,000	$ 3,983,000	$ 3,677,000	$ 4,231,000	$28,068,000
Laser Scanner for Feature Assessment	$ -	$ -	$ -	$ -	$ 150,000	$ -	$150,000
Easement Acquisition for CP	$ 210,000	$ 215,000	$ 220,000	$ 225,000	$ 230,000	$ 235,000	$1,335,000
CP Upgrade Programme	$ 629,000	$ 642,000	$ 648,000	$ 648,000	$ 648,000	$ 648,000	$3,863,000
CP Telemetry Installation	$ 150,000	$ 150,000	$ 150,000	$ 150,000	$ 150,000	$ -	$750,000
Total Forecast Capex	$ 6,127,000	$ 8,300,000	$ 9,819,000	$ 5,336,000	$ 6,655,000	$ 6,234,000	$42,471,000

Proposed costs (rates and volumes) are based on the following.

ILI – amounts are based on vendor quoted costs, typically standard rates for inspection type x length of pipeline / no. of sections). These are competitively tendered, and currently APA has a preferred ILI vendor selected by a competitive tender process. A new panel tender for ILI services panel is underway in 2016/17 and cost rates are likely to be similar. Some services such as EMAT pigging are not available from all vendors, in which case the pricing is negotiated and agreed with the available vendor/s.

A breakdown of the forecast ILI costs is provided below.

Project / Programme	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
RBP DN250 EMAT ILI - Crack Detection		$ 1,800,000	$ 1,200,000			
Metro MFL - 5 year cycle	$ 220,000					$ 220,000
Coll-Ell MFL - 10 year cycle			$ 10,000	$ 190,000		
Lytton MFL - 7 year strategic	$ 5,000	$ 140,000				
DN250 MFL - 5 year cycle			$ 1,500,000			
DN400 MFL - 10 year cycle					$ 1,800,000	
Metro EMAT - re run 5-6 year cycle / technology improvement						$ 900,000
ML1 MFL - 7 year strategic			$ 120,000			
Gibson DN200 MFL - 7 yr cycle		$ 60,000				
PEAT MFL - 10 year				$ 140,000		
ILI Total	$ 225,000	$ 2,000,000	$ 2,830,000	$ 330,000	$ 1,800,000	$ 1,120,000

Coating refurbishment and life extension – Number of excavations required each year has been developed from APA's integrity modelling based on ILI data, taking into account site verification of ILI results, tool tolerance, and corrosion growth rates. The cost per excavation has been calculated from the FY16 work programme actual costs, taking into account the variation in complexity and cost between metropolitan and rural work sites. The programme is managed prudently in accordance with APA's Infrastructure Development major project framework. Contractors and materials are sourced by competitive processes in accordance with APA procurement policy including a formal tender process for the pipeline excavation and coating upgrade works.

Project / Programme	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
Metro excavation and upgrade costs	$ 1,562,000	$ 1,880,000	$ 2,083,000	$ 839,000	$ 637,000	$ 405,000
Rural excavation and upgrade costs	$ 3,351,000	$ 3,413,000	$ 3,888,000	$ 3,144,000	$ 3,040,000	$ 3,826,000
Integrity Upgrade Total	$ 4,913,000	$ 5,293,000	$ 5,971,000	$ 3,983,000	$ 3,677,000	$ 4,231,000

Laser scanner costs are a vendor price – the existing unit was procured in 2016 and APA expects replacement to be due around a 5 year interval.

CP Upgrades and Easements – this programme is a continuation of current spend profile based on steady increase in work required each year. Refer CP Plan. CP materials/contractors are competitively tendered, new panel currently being evaluated. Procurement requirements will be followed for all CP materials and contractor costs.

CP Telemetry – continuation of current programme – design is being rolled out. Expect completion in FY21.

All cost estimates are based on recent or current similar programme costs. A breakdown of costs to labour, materials, contractors and other costs is provided in the below table.

	ILI	Excavations	Laser Scanner	CP Easement	CP Upgrades	CP Telemetry	TOTALS
Labour	$ 539,825	$ 6,848,592	$ 5,000	$ 105,000	$ 347,500	$ 395,842	$ 8,510,559
Materials	$ -	$ 2,020,896	$ 145,000	$ -	$ 2,213,000	$ 234,767	$ 4,613,663
Contractors	$ 7,632,295	$ 17,795,112	$ -	$ 880,000	$ 1,264,000	$ 108,386	$ 27,560,743
Other	$ 132,880	$ 1,403,400	$ -	$ 350,000	$ 38,500	$ 11,005	$ 1,786,035
TOTAL	$ 8,305,000	$ 28,068,000	$ 150,000	$1,335,000	$ 3,863,000	$ 750,000	$ 42,471,000

Appendix A – Source documents

DNV GL – Independent Review Report

QLD PIMP

National ILI Policy

CP Plan for RBP

Stress Corrosion Cracking Management Plan for RBP

APA Stress Corrosion Cracking Expert Guide

TECHNICAL REVIEW

Technical Review of RBP Pipeline Integrity Management Business Case

APA Group

Report No.: PP161132-01, Rev. 2
Document No.: -
Date: 2016-08-15

Project name:	Technical Review	Det Norske Veritas Pte. Ltd.
Report title:	Technical Review of RBP Pipeline Integrity Management Business Case	DNV GL Oil & Gas
Customer:	APA Group	DNV GL Technology Centre
Contact person:		16 Science Park Drive
Date of issue:	2016-08-15	118227 Singapore
Project No.:	PP161132	Singapore
Organisation unit:	Integrity Solution	Tel: +65 6508 3750
Report No.:	PP161132-01, Rev. 2	
Document No.:	-	

Task and objective:

The main objective of the project is to perform an external technical review and validation of the proposed integrity management business case prepared by APA for Roma Brisbane Pipeline (RBP) in Queensland, Australia. The main document that has been reviewed is the APA Business Case document for the RBP integrity management programme, including the in-line inspection, excavation, repairs and coating refurbishment, cathodic protection upgrade and risk assessment for the RBP Pipeline. The outcome of the study is the gap finding of the Business case based on the APA pipeline integrity management guideline and other best industrial practice.

Prepared by:	Verified by:	Approved by:
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Rev. No.	Date	Reason for Issue	Prepared by	Verified by	Approved by
2	2016-08-15	Final issue	Huraizah Nor/Azura Sharina	Hilman Salleh	Kevin Young

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1 EXECUTIVE SUMMARY

DNV GL was requested by APA to carry out a review of its RBP Pipeline Integrity Management Business Case Number AA-03 Revision 2. The focus of the review regards the technical content of the pipeline integrity management program for the RBP pipeline. Commercial considerations are excluded from the scope of work. The work identified in this document is necessary to maintain the safety and integrity of services. It is also in accordance with accepted industry practice.

Based on the high level technical review performed by DNV GL, below are the main findings for APA consideration;

a) DNV GL believes that the inspection techniques proposed are appropriate for the purpose of anomaly detection and monitoring as part of the integrity management of the pipelines. DNV GL also supports the use of further anomaly assessments using AS 2885.3, ASME B31G, Modified B31G and Effective Area calculation methodologies as mentioned in the Business Case to prioritise locations that may require excavation for repair and maintenance.
b) DNV GL supports the need for excavation as part of pipeline integrity assurance and upgrade programme. The extent of the excavation programme proposed by APA will provide not only the opportunity to confirm the anomalies found and thus the reliability of the inspection and condition of the pipeline; it will also provide an opportunity for concurrent repair and/or upgrading work to ensure continuous safe operations.
c) APA has put together a concise five year plan for the upgrade of the RBP Cathodic Protection (CP) system which includes the Philosophy behind the proposal along with costings. DNV GL supports the need and scale of APA's proposed Cathodic Protection Upgrade Programme.
d) DNV GL supports the need for SCC direct assessment by excavation, in situ inspection and ILI inspection techniques, including EMAT. This will provide opportunity to confirm the identified crack and detail inspection to understand the condition of the pipeline. Moreover, it will also provide an understanding of areas where locations of high strain may or can occur in the pipeline.
e) DNV GL supports the risk assessment conducted by APA for the RBP pipeline. The Pipeline Safety Management Study has been conducted for the pipeline based on the guideline for Safety Management Process (SMS) provided in the AS2885 Part 1. The risk analysis assessed the pipeline threat (internal and external), consequence of any failure and suitable mitigation/control action to bring the risk to the ALARP level for safe operation.

The pipeline integrity management process continues throughout the life of the pipeline to ensure that the pipeline is operated in a safe, effective and efficient manner and that the risk of pipeline failure is managed to an as low as reasonable practicable (ALARP) considering health and safety and security of supply.

DNV GL supports APA's Pipeline Integrity Management Plan and its proposals outlined in this Business Case as that needed to manage the safety and operational integrity of this pipeline for the forecasted period.

2 INTRODUCTION

DNV GL was requested by APA group to perform an independent technical review of the proposed integrity management business case prepared for Roma Brisbane Pipeline (RBP) in Queensland, Australia.

The RBP system includes over 800km 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. All buried pipelines constructed of steel pipe are subject to coating deterioration and corrosion from the soil environment and require integrity management to maintain safe operations and comply with standards and legislation.

The RBP has particular characteristics such as over-the-ditch tape coating system and the pipeline age that result in significantly greater effort and expense in corrosion and integrity management than most other pipelines in Australia. If not sufficiently 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.

Since pipeline integrity management activities are an essential part of safely operating the RBP, an independent review of the proposed integrity management programme prepared by APA has been performed to assess the completeness and that an effective pipeline integrity management system is continued and the pipeline risks are manage to an acceptable level.

Therefore, DNV GL undertakes the role to perform a technical review for the business case and supporting document and provide an independent third party opinion and expert recommendation for APA consideration.

3 SCOPE OF WORK

The main scope of work is as follows:

a) To review APA's integrity management business case number AA-03 Revision 2 and supporting documents (ILI reports, CP reports, other historical data, etc.) and other information as may be required. Overall it is a high level review, i.e. to the level of detail to enable DNV GL to form an opinion on the suitability and adequacy of the programme overall.
b) To meet and discuss the material with APA as required, phone or videoconference as required.
c) To prepare and submit a technical review and validation report containing DNV GL's opinion on the technical suitability of and need for the programme.

4 DOCUMENT LIST

4.1 Reviewed Document

The main document that is reviewed is the RBP Pipeline Integrity Management-Business Case Number AA-03 Revision 2, including the intelligent pigging, excavation, repairs and coating refurbishment, cathodic protection upgrade and risk assessment for the RBP Pipeline. Other documents were also reviewed in conjunction to this work as listed below:

a) APA Pipeline Integrity Management Plan (PIMP) Queensland Transmission System Guideline, Document Number:320-PL-AM-0027, 30th March 2015
b) AS 2885.3 Pipeline Gas and Liquid petroleum, Part 3 Operation and Maintenance, 2012
c) Stress Corrosion Cracking Management Plan, Document Number:320-PL-AM-0031, 29th July 2015
d) 5 Year Maintenance and Upgrade Plan for the RBP CP System, Revision A, 4th May 2015
e) Integrity Update DN250 RBP, DN300 METRO and DN200 METRO, December 2015

5 ASSUMPTION AND LIMITATION

The assumption and limitation made in the review are as follows:

a) The high level review only covered the technical part of pipeline integrity management programme exclude any financial review.
b) The review was performed based on APA Pipeline Integrity Management Plan (PIMP) Queensland Transmission System Guideline (Document Number: 320-PL-AM-0027, 30th March 2015) and other similar industry experience of similarly aged or complexity of pipeline.
c) The review section consists of the following and not limited to:
    i. Quantities of digs;
    ii. Repairs projected;
    iii. Scale and quantity of CP upgrades;
    iv. Type and frequency of inline inspections;
    v. Inspection Type and Frequency;
    vi. Risk Assessment;
    vii. Any additional key factors.

6 FINDINGS OF THE REVIEW

The below sub topic discussed about the findings of the document review:

6.1 In-line Inspection (ILI) - Section 3.3

The technology of In-line Inspection (ILI) has become a reliable tool used in pipeline integrity assessments. If used properly, ILI also known as intelligent pigging, provides many efficiencies and economies in integrity assessment at a relatively small risk. This technology evolved in the 1960s when operators began to use some form of instrumented inspection technology where originally, the primary means of establishing pipeline integrity has been through the use of pressure testing.

When examining the condition of a pipeline, ILI utilising various Non-Destructive Testing (NDT) methods is an essential tool and a significant factor in establishing a quality management program that ensures safe, cost effective operation of the pipeline. It should be understood that there is no NDT technology or technique that is universally applicable. In some cases, a combination of techniques is used to quantify the findings. Therefore, pipeline operators and inspection service companies jointly choose the appropriate technology for each particular situation. In addition, the level of defect specification needed is matched to the performance of the tool.

Hence, for APA, there were four different forms of ILI mentioned. These are:

a) High-resolution magnetic flux leakage (MFL) inspection – detects corrosion, gouges, grooves, mill defects and other metal loss features

b) Geometry or caliper inspection – detects dents, ovality (out of roundness) and similar – can indicate 3rd party mechanical damage, rock dents from flooding or landslides

c) XZY (3-dimensional) inertial mapping – Maps the geographical position of the pipeline centreline and records any movement or change in shape since previous inspection. Curvature and strain analysis is a key factor in mitigation of circumferential stress corrosion cracking and for the assessment of geotechnical hazards.

d) Electro-Magnetic Acoustic Transducer (EMAT) inspection – recently developed technology that detects cracking and crack-like features. Used in the RBP to detect and manage stress corrosion cracking and longitudinal weld anomalies.

The MFL technique highlighted above is the most commonly used ILI technology. The technique is similar to Magnetic Particle Inspection but without the use of an ink. The component/area is magnetised to a level at which the presence of a significant local reduction in material thickness caused distortion of the internal magnetic field to allow flux lines to break the test surface at the location of the discontinuity.

Geometry or caliper pigging is a powerful tool for secondary inspection. The tool will continuously measure the internal diameter through an array of sensing fingers in contact with the pipe wall. As the tool moves through the pipeline, all radial sensor movement are detected and recorded.

The EMAT principal is based on the conventional ultrasound generation technique where transducers produced ultrasound wave pulses are fed into the pipe wall via a coupling liquid. However, the EMAT transducers are dry-coupled. For transmission into the pipe wall, an alternating current in a wire induces an eddy current in the metal surface. When this is combined with a static magnetic field, a force is produced which causes the steel metal grid to oscillate, thus launching a guided ultrasound wave in the pipe wall. Breaks in the homogeneity of this metal grid (i.e. defects such as cracks) will result in reflections of the sound wave. These reflected waves encountering the magnetic field will generate an eddy current, which in turn, induces a current in the wire. This current forms the received signal, which can be further processed and analysed. The signal's characteristics and its time of receipt, when combined with the signals of other sensors, provide accurate information about the feature's size, depth and location.

DNV GL believes that the techniques mentioned above are appropriate for the purpose of anomaly detection and monitoring as part of the integrity management of the pipelines. Additionally the proposed technologies represent the present "State of the art" for ILI and as such represent the most thorough methods available presently to detect and quantify anomalies. By utilising the techniques mentioned above, APA should be able to obtain reliable and critical information about the pipelines that are inspected and make informed decisions on further actions to the taken such as anomaly assessments and/or fitness for purpose assessments to make run, repair or replace decisions, if any, to maintain pipeline integrity for continued operation.

DNV GL supports the reduction of the ILI frequency on the DN250, DN300 and DN200 pipeline sections to five years based on the existing integrity situation. This is in-line with DNV GL's experience of similarly aged complex pipelines.

DNV GL also supports the use of further anomaly assessments using AS 2885.3, ASME B31G, Modified B31G and Effective Area calculation methodologies as mentioned in the Business Case to prioritise locations that may require excavation for repair and maintenance.

The use of a software tool such as the Integrity Data Management Tool (IDMT) is a positive investment made by APA. This will improve the management of the pipelines in terms of data, inspection, anomaly and repair management.

6.2 Excavation and Integrity Update Programme Review – Section 3.4

Excavation based on ILI results are an essential aspect on an integrity program. This typically involves a section of the pipeline being excavated and further inspection for verification and assessments. If required, repairs are then being conducted and the site is backfilled and restored to the original condition or better.

The number of proposed excavations presented in the Business Case is as follows:

Year	FY17	FY18	FY19	FY20	FY21	FY22
Metro #	27	33	36	15	11	7
Non-Metro	81	83	94	76	74	93
Total	**108**	**115**	**130**	**91**	**85**	**100**

These numbers are based on anomaly assessments from previous ILI inspection results. DNV GL views the number of predicted excavations as in-line with the number of anomalies recently identified.

It was recognised that APA and its contractors have the capability and experience to conduct such excavations. This is highlighted in numerous previous successful works. Prior to excavation, various assessments on anomaly findings from the ILI have been conducted. With this, the anomalies will then be prioritised and the decision whether to excavate or not will be made.

Further to this, the number of proposed excavations is also prioritised based on risk assessments which include considerations to factors such as type of defect, severity of the defect, location of the pipeline section etc.

DNV GL supports the need for excavation as part of pipeline integrity assurance and upgrade programme. This will provide not only the opportunity to confirm the anomalies found and thus the reliability of the inspection and condition of the pipeline; it will also provide an excellent opportunity for any repair and/or upgrading work.

6.3 Cathodic Protection Upgrade (CP) Review – Section 3.5

Corrosion Control on the RBP

The RBP pipeline systems primary mitigation against corrosion risk is a protective coating. The secondary mitigation for a buried pipeline is the use of a Cathodic Protection (CP) system.

Elements of the RBP were first commissioned in 1969. The pipeline was installed with an 'Over-the-ditch' single layer tape wrap during its construction at the field site.

Tapes applied over the ditch are more susceptible to deficiencies in surface preparation and to variable temperature and humidity conditions that can affect the condition of the steel or the bonding properties of the adhesive. The tapes are spirally wrapped mainly by machine with small sections by hand as required. Polyethylene (PE) tape coatings are laminated, so delamination can be a problem. Delamination causes the PE film backing to be suspended (disbonded) around the pipeline, impeding the passage of current (CP shielding). Delamination is typically accelerated by soil stress. Even with proper application, some tapes can be affected by soil stress because the backing compounds easily stretch. In clay soil, the PE backing is moved when the soil attaches itself to the PE. Alternate wetting (expansion) and drying (contraction) pulls the PE backing.

The solid backing normally shields CP currents, and, if water penetrates, corrosion occurs. The main problems with tape coatings include:

a) Shielding of cathodic protection current;

b) Disbondment, especially at welds and dents;

c) Damage due to rock impingement;

d) Soil stress problems;

e) Tenting that occurs between the pipe surface and the tape along the ridge created by the longitudinal weld reinforcement.

f) High susceptibility to Stress Corrosion Cracking (SCC).

As coatings deteriorate over time and as the pipeline is buried, then the Cathodic Protection becomes the dominant method of preventing/minimising corrosion.

The outcome of this is the greater reliance on the CP system as the pipeline demands increasing levels of current to protect it from corrosion. The greater current demand reduces the life of the groundbed anodes as they are 'spent' much quicker in these conditions.

From the supplied documentation it can be seen that APA's CP systems are monitored on a regular basis for their effectiveness. However, additional risks such as disbondment of the old tape coating and CP shielding – which is not easily recognised through monitoring and therefore still gives risk to corrosion of the pipeline.

APA appear to have recognises the risks of corrosion to the RBP pipeline and has identified the contributing factors of failing aged tape coatings and increased current demands of its an aging hard worked CP system.

Assumptions:

CP design life for new and good pipeline coatings is generally 20 years, However when fitting retrospect groundbed anodes to deteriorating coatings, then a much more conservative figure should be used. In this case, APA has used 15 years – which is reasonable for the size of the system and the condition of the pipeline coating.

There are currently 69 CP systems (Groundbeds and Transformer Rectifiers 'TR's') on the RBP system. APA estimates that a rolling replacement of the 69 CP systems every 15 years (design life expectancy). DNV GL considers this to be adequate based on previous experience and the supporting documented evidence.

CP systems have been built up from a small number of systems (at original commissioning) to the current 69 systems over time, so therefore will be of varying ages.

Some of the CP systems will be less than 15 years old and some will have been renewed in the past 15 years or so. However, it is reasonable to assume going forward that the 69 CP systems will require ongoing replacement at a rate of five per year (69 systems / 15 years design life)

The increased current demand and voltage outputs has also placed large strains on the aging existing TR units and these have been subjected to burn out and failures resulting in issues with regulating the correct current outputs.

Recent improved designs for TR's include automatically controlled units with increased surge protection and self-limiting controllers which reduce burn out and will be needed to power the higher capacity groundbeds.

Improved design for TR's includes:

a) **Constant current mode** - automatically maintains DC output current at a pre-set level.

b) **Potential control mode** - automatic control to maintain the pipe-to-electrolyte potential at pre-set level in response by a signal from a reference electrode

These improvements will provide the RBP CP system with a greatly improved robust and reliable source of current.

Linking these up to remote monitoring means that CP system downtime is recognised instantly and the technician is able to respond immediately and restore any lost supply. It also allows for the technician to prioritise workload to faults rather than spending large amounts time and distance travelling between CP supplies, in order to check whether it is working sufficiently or not.

APA has put together a concise five year plan for the upgrade of the RBP CP system which includes the Philosophy behind the proposal along with costings. DNV GL supports APA Cathodic Protection Upgrade Programme as being appropriate for the age of the system and the level of current demand needed to continue to mitigate corrosion risk. It is noted that the proposed coating repairs will also assist in maintain the CP demand within scope of the proposed upgrade.

6.4 Stress Corrosion Cracking (SCC) Review – Section 3.6

This section is aimed at providing overview of stress corrosion cracking (SCC) of RBP pipelines exposed to near-neutral pH environments and corresponding integrity strategies being developed based on the understanding of the cracking mechanisms and APA experience. The details failures and findings on the RBP pipeline are specified in the Roma Brisbane Pipeline (RBP) Stress Corrosion Cracking Management Plan (Doc Ref: 320-PL-AM-0031).

The formation of cracks on RBP pipeline is caused by various factors combined with the surrounding of the pipeline. SCC occurs as a result of a combination between corrosion and stress. In RBP case, the conditions are;

a) The susceptibility of the material
    i. Pipeline qualities which include type of steel, cleanliness of the steel and pipe surface condition

b) Ongoing PE tape coating damage and disbondment resulting from stress imposed due to soil movement.

c) The environment surrounding the pipeline
    i. Soil type that is conducive to SCC with presence of CO_2 in the groundwater.
    ii. Potential shielding of CP, resulting in a low pH environment on the pipe surface where the coating is disbonded.

d) Stresses including hoop stress from internal pressure, residual stress from pipe manufacture or construction and bending strain over the operation period.

Both circumferential and longitudinal stresses are discussed in the Business case based on previous failures and findings. Details on location of most cracks occur are documented in the business case but not in the management plan. Based on the historical data, it is confirmed that the failures have mainly occurred on the parent material not on the weldment.

The near-neutral pH form of SCC is transgranular where the cracks propagate through the grains in the metal, where the areas have experienced metal loss from corrosion. Thus, it is mentioned in the business case that the Canadian Energy Pipeline Association (CEPA) guideline is used.

RBP pipeline has experienced failures of SCC resulting in leaks. This has established the extent of SCC susceptibility of the pipeline. Furthermore, APA has utilizes the inspection survey to identify cracks using SCC direct assessment method during excavation. Detail ultrasonic inspection is conducted on the identified cracks and acceptable criteria have been developed to address the fine and shallow crack either by buffing or grinding. It is mentioned that for the remaining cracks, fitness for service is conducted to determine the repair options or replacement action as required. The basis for the assessment and repair criteria is outlined in APA Expert Guide Stress Corrosion Cracking Management.

As part of the SCC management plan, APA is proposing the use ILI to identify areas of crack, corrosion and strain on the pipeline. The information will help in further strain analysis and determine any ground movement occurs along the pipeline.

DNV GL supports the need for excavation, in situ inspection and ILI inspection including EMAT technology as part of SCC direct assessment. This will provide opportunity to confirm the identified crack and detail inspection to understand the condition of the pipeline. Moreover, it will also provide an understanding of areas where locations of high strain may or can occur in the pipeline.

Based on both business case and SCC management plan, most of the fitness for service assessment conducted today on the RBP pipeline is more of corrective action on the identified crack. Once the crack is further analysed, preventive action of pipeline rupture is done by implementing the most appropriate mitigation. With the technology deployment of the inertial mapping tool from the ILI, more data can be collected and an SCC model can be developed to further understand the location and condition the pipeline will experience SCC. The model can be done as part of Fitness for Service (FFS) or MARV™ (Multi Analytic Risk Visualization) assessment. This will result in optimizing the excavation area without compromising the integrity of the pipeline.

6.5 Risk Assessment Review – Section 5

A Pipeline Safety Management Study has been conducted for the RBP pipeline based on the guideline for Safety Management Process (SMS) provided in the AS2885 Part 1. The risk analysis assessed the pipeline threat (internal and external), consequence of any failure and suitable mitigation/control action to bring the risk to the ALARP level.

The threat assessment considers the threat with potential damage the pipeline, cause interruption to service, cause of release of fluid from the pipeline, cause harm to pipeline operators, the public or environment. Effective control for each credible threat is also considered in the assessment based on the recommended interval, risk rank and the severity of the event.

The current summary of the RBP pipeline risk assessment as shown in Table 3 of the Business Case shows that most risks are managed to a level of Low, with the exception of Axial SCC and/or Undetected Cracking, which was assessed as Intermediate/ALARP.

From the supplied documentation it can be seen that APA's manage the risk of the pipeline by using the guideline provided in the AS2885 Part 1 using a deterministic approach.

DNV GL supports this approach to manage the risk of the pipelines and believes that the risk level would increase substantially if the proposed works were not undertaken.

7 CONCLUSION

The operation of the onshore gas industry in Queensland is regulated by a range of laws, standards, codes of practice and guidelines meaning that APA has a legal obligation to operate a safe, effective and efficient gas transmission pipeline system.

Some of the relevant Regulations, Standards and Procedures are stated below:

Queensland Petroleum and Gas (Production and Safety) Act 2004

The purpose of this Act is to facilitate and regulate the carrying out of responsible petroleum activities and the development of a safe, efficient and viable petroleum and fuel gas industry.

AS 2885 Pipelines – Gas and Liquid Petroleum

The overarching Standard that applies to the pipeline industry in Australia is AS 2885 which relates to the design, construction, testing, operations and maintenance of gas and petroleum pipelines that operate at pressures in excess of 1050kpa (10.5Bar) The many other standards used by the pipeline industry are referred to in AS 2885 as the principal document.

AS 2885.3— Pipelines - Gas and Liquid Petroleum Part 3: Operation and Maintenance

Section 5 – Pipeline Integrity Management:

The Licensee shall ensure continued pipeline integrity during the life of the pipeline. As part of the pipeline management system, the Licensee shall prepare and implement a pipeline integrity management plan (PIMP) for the operation and maintenance of the pipeline.

APA Pipeline Integrity Management Plan - Queensland Transmission System

The PIMP summarises the key integrity actions that are performed on a specific asset or set of assets.

The company has adopted the AS 2885.3 standard as the requirement for maintaining the integrity of all buried transmission pipeline assets. This PIMP has been prepared in accordance with the provisions and requirements of AS2885.3

National Gas Rules

The National Gas Rules objective is to promote efficient investment in, and efficient operation and use of, natural gas services for the long-term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.

Pipeline integrity management activities are an essential part of operating a pipeline. DNV GL was requested by APA group to perform an independent technical review of the proposed integrity management business case document prepared for Roma Brisbane Pipeline (RBP) in Queensland, Australia.

The RBP System had no formally identified design life at the time of 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 a similar RLR is in progress on the DN250 section.

APA has outlined a practicable approach to ensuring the ongoing integrity of this aging asset in line with the requirements of AS 2885.3 and the supporting PIMP.

DNV GL has carried out a high level review of the RBP Pipeline Integrity Management Business Case Number AA-03 Revision 2 alongside supporting documents and specifically in the areas:

a) Inline inspection (ILI)

b) Excavation, integrity works and new coating upgrades

c) CP upgrades

d) Stress Corrosion Cracking (SCC)

e) Risk Assessment

DNV GL Supports APA's Pipeline Integrity Management Plan and its proposals outlined in this Business Case.

8 REFERENCES

The main references for this document review are listed as follows:

1. APA Pipeline Integrity Management Plan (PIMP) Queensland Transmission System Guideline, Document Number:320-PL-AM-0027, 30th March 2015

2. AS 2885.3 Pipeline Gas and Liquid petroleum, Part 3 Operation and Maintenance, 2012

3. AS 2885.1 Pipeline and Liquid Petroleum, Part 1 Design and Construction, 2012

4. Stress Corrosion Cracking Management Plan, Document Number:320-PL-AM-0031, 29th July 2015

5. 5 Year Maintenance and Upgrade Plan for the RBP CP System, Revision A, 4th May 2015

6. Integrity Update DN250 RBP, DN300 METRO and DN200 METRO, December 2015

About DNV GL

Driven by our purpose of safeguarding life, property and the environment, DNV GL enables organizations to advance the safety and sustainability of their business. We provide classification and technical assurance along with software and independent expert advisory services to the maritime, oil and gas, and energy industries. We also provide certification services to customers across a wide range of industries. Operating in more than 100 countries, our 16,000 professionals are dedicated to helping our customers make the world safer, smarter and greener

320 Asset Management

PLAN

PIPELINE INTEGRITY MANAGEMENT PLAN

Queensland Transmission System

Owner	M. Fothergill	Next Review Date			March 2020
Document No	320-PL-AM-0027				

Rev	Date	Status	Originated	Checked	Approved	Signature
1	30/03/2015	First Issue	Nick Le	Jonathan Bryan	M. Fothergill	7/12/15.

APA Group

REVISION RECORD

Revision No.	Date	Description	Originated	Checked	Approved
1	30/03/2015	First issue	N. Le	J. Bryan J. Ward f. Carroll	M. Fothergill

IMPLEMENTATION

The Pipeline Integrity Management Plan (PIMP) is required by AS 2885.3-2012 and has been developed from a national template for implementation throughout APA Group. The PIMP implementation will be managed locally.

RESPONSIBILITY

The following signatures represent the commitment from the key operating group leaders to manage their operational management and maintenance responsibilities in compliance with the requirements of the PIMP and to ensure that the PIMP is routinely maintained and reflects the business activity.

Infrastructure Development	**Craig Bonar** Manager East Coast Grid Engineering Infrastructure Strategy and Engineering	
Transmission Operations	**Paul Thorley** Manager Field Services North East Transmission Operations	

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1 INTRODUCTION

The Pipeline Integrity Management Plan (PIMP)is a component of APA's Pipeline Management System developed alongside nationally maintained documentation which detail the asset management requirements and techniques used generically on pipeline assets.

The PIMP summarises the key integrity actions that are performed on a specific asset or set of assets. The technical logic behind APA's standard integrity processes is contained in the PMS documents rather than the asset specific PIMP to avoid duplication and optimise control. The PIMP may though also detail some asset specific requirements. Where necessary the other PMS documentation, which is controlled on The Hub, should be referred to.

The PMS is structured so that the QLD specific Pipeline Management Plan contains static information relating the pipelines, such as a detailed asset description for each pipeline, whereas, the PIMP contains dynamic information and is subject to on-going management.

This document reviews the current integrity and the maintenance requirements determined to ensure safe and reliable operations.

The company has adopted the AS 2885.3 standard as the requirement for maintaining the integrity of all buried transmission pipeline assets. This PIMP has been prepared in accordance with the provisions and requirements of AS2885.3

The Pipeline Management Plan Chapter 3 – QLD Operations sets out the legislative framework, reporting and auditing requirements for Queensland assets.

1.1 Governance

This PIMP is a dynamic document subject to ongoing updates and as such should be considered and Managed as a "live" document.

The adequacy of the PIMP shall be reviewed at least every 5 years or when a potential failure mechanism is identified and immediately following a pipeline failure event.

To facilitate the on-going review and management of this PIMP, and the actions arising from this PIMP, an annual management review meeting shall be held and will include key stakeholders, including, but not limited to, representatives from:

- Infrastructure Strategy and Engineering
- Field Services
- Asset management
- Compliance
- HELM
- Maintenance Planning

The intention of the PIMP review meeting is to monitor the management of the PIMP and provide a platform to discuss proposed and upcoming changes, action items and the effectiveness of the PIMP. The PIMP review meetings are subject to an agenda and are minuted.

The approval and review of this document is the responsibility of the General Manager of Infrastructure Strategy and Engineering as outlined in the 320-MX-AM-0001 "AS 2885.3 Approval Matrix".

APA Group's structure and organisation chart shows the lines of authority and communication within APA. This structure applies to the control of all work. Organisational charts are not contained in this PIMP as they are dynamic and continually changing but they are available to all personnel on the APA Intranet site. Further, each employee at APA Group, including those responsible for control of work, has a job description which specifically details their responsibilities.

Failure mechanisms identified in the review shall be actioned and evaluated against the effectiveness of the PIMP. Structural integrity based reviews shall be carried out as described in section 2.1 to ensure that this PIMP is consistent with pipeline system structural condition and forms the basis to determine the Remaining Life Review described in section 6 of this PIMP is valid.

1.2 Scope

This PIMP relates to the Queensland Assets as defined below. There are a total of 11 current pipeline licences that cover a length of approximately 4,000 km of buried pipeline with varying age, pipe size, coating type, and operating conditions.

In total there are 13 compressor stations associated with the pipeline system.

A summary of the QLD Assets are contained in the tables below (**Table 1**,

Table 2 and

Table 3).

Table 1 – Queensland Pipeline Licenses

License	Pipeline Name
PL 2	Roma to Brisbane Pipeline
PL 24	South West Queensland Pipeline
PL 41	Carpentaria Gas Pipeline
PL 42	Cannington Lateral Gas Pipeline
PL 50	Mica Creek Meter Station
PL 51	Mt Isa Lateral
PL 74	Peat Lateral
PL 120	Kogan North Central Gas Processing Facility
PL 123	Berwyndale to Wallumbilla Pipeline
PL 129	QSN Link (Queensland Portion)

Table 2 – South Australia Pipeline Licenses

License	Pipeline Name
PL 18	QSN Link (SA Portion)

Table 3 - Specification of the Compressor Stations

Pipeline name	Compressor Station Location	Capacity (MW)	Compression Ratio	Compressor type	Driver type	Number of 'Standby' Units	Number of Unit(s)
Roma Brisbane Pipeline (RBP)	Oakey	1.0 – 2.5	1.0 – 1.5	Centrifugal	Turbine	Nil	One single unit T1602 S20 – C168 wet seal compressor
	Dalby	4.6 – 6.0	1.0 – 2.0	Centrifugal	Turbine	Nil	One single unit Centaur compressor - T6100 C50 C33 compressor
	Kogan	1.0 – 2.5	1.0 – 1.5	Centrifugal	Turbine	Nil	One single unit T1602 S20 – C168 wet seal compressor
Carpentaria Gas Pipeline (CGP)	Morney Tank	1.0 – 2.5	1.5 – 2.5	Centrifugal	Turbine	Nil	One single unit T1602 S20 – C166V dry seal compressor
	Davenport Downs	4.0 - 6.0	2.0 - 2.5	Centrifugal	Turbine	Nil	One single unit T6100- C50 – C334 dry seal compressor
South West QLD Pipeline & Expansions (SWQP & QSN)	Wallumbilla Compressor Station WCS1	0.5 – 0.99	2.0 – 2.5	Reciprocating	Reciprocating gas engine	Nil	3 units of Waukesha L7044GSI engines, Ariel JQK/4 compressors
	Wallumbilla Compressor Station WCS2	1.0 – 2.5	2.0 – 2.5	Reciprocating	Reciprocating gas engine	Nil	3 unit s of Caterpillar G3608LE engines, Ariel JGK/4 compressors
	Wallumbilla Compressor Station WCS3	6.0 – 10.0	2.0 – 2.5	Centrifugal	Turbine	1	3 units Solar Mars 90
	Cooladdi (QCS4)	4.0 – 6.0	2.0 – 2.5	Centrifugal	Turbine	1	2 units of Solar Taurus T60 Version 7802 EH engines, Solar C3341 compressors

Pipeline name	Compressor Station Location	Capacity (MW)	Compression Ratio	Compressor type	Driver type	Number of 'Standby' Units	Number of Unit(s)
	Moomba CS	6.0 – 10.0	2.0 – 2.5	Centrifugal	Turbine	1	3 units Solar Mars 90
Kogan North Central Gas Processing Facility	Kogan North KON-K01,2,3	0.5 – 0.99	10-100	Reciprocating	Reciprocating	Nil	3 units Caterpillar G3516 – Ariel JGE4 Recip (4-stage)

1.3 Key Design Features

Table 4 –Key Pipeline Design Features

Pipeline Name	Pipeline License	MAOP [kPag]	Length [km]	Diameter [DN]	Coating Type	Wall Thickness min, max[mm]	Grade[API 5L]	Year Const.
RBP – DN250 "Mainline" from Wallumbilla to Bellbird Park – 7 sections	PL 2	7,136	399	250	Single-layer Polyken Polyethylene tape wrap with 25% overlap	4.78, 5.16, 6.35	X46	1968
RBP – DN400 "Looping" from Wallumbilla to Swanbank – 7 sections		9,300 Wallumbilla to Condamine 9,600 (Condamine to Swanbank)	404	400	Extruded High Density Polyethylene with some PE tape joints and some heat shrink sleeves	6.4, 6.6, 7.7, 7.9, 9.5, (X60) 5.7, 6.8, 8.1, 9.7 (X70) 8.85 (X80)	X60, X70, X80	1988 - 2002
RBP – DN300 "Metro" from Bellbird Park to SEA block valve		4,612 (Bellbird Park to Mt Gravatt) 4,200 (Mt Gravatt to SEA MLV)	38.6	300	Double-layer Polyken polyethylene tape wrap with 55% overlap	5.16, 6.35, 7.92, 8.38	X42	1968
RBP – DN200 from SEA block valve to Gibson Island Meter Station		4,200	2.1	200	Double-layer Polyken polyethylene tape wrap with 55% overlap	4.78	X52	1968
RBP - Lytton Lateral from SEA block valve to Lytton Meter Station		9,600	5.6	200	Fusion Bonded Epoxy(FBE)	8.18	X52	2010
RBP - "Metro Looping 1" from Carina (Mile post 268.4) to Paringa Road Scraper Station		10,200	5.8	400	Dual Layer FBE	12.7	X70	2012

Pipeline Name	Pipeline License	MAOP [kPag]	Length [km]	Diameter [DN]	Coating Type	Wall Thickness min, max[mm]	Grade[API 5L]	Year Const.
RBP – Collingwood-Ellengrove Lateral from Collingwood Park take off to Ellen Grove		9,600	9.4	400	Extruded High Density Polyethylene with PE tape joints	9.5	X60	2001
South West Queensland Pipeline (SWQP)	PL 24	14920	755	400	Fusion Bonded Epoxy(FBE) with field applied epoxy joints	9.4, 13.6	X52	1996
South West Queensland Pipeline Expansion (SWQPE)	PL 24	15300	755	450	Dual Layer FBE with field applied epoxy joints	8.1, 9.7, 10.8	X70	2012
QSN Link	PL 129 (QLD Portion)	15,300	90	400	Trilaminate with Heat Shrink Sleeves	8.1, 9.7, 10.80	X70	2007
	PL 18 (SA Portion)	15,300	92	400	Trilaminate with Heat Shrink Sleeves	8.1, 9.7, 10.80	X70	2007
QSNE	PL129 (QLD portion)	15,300	90	450	Dual Layer FBE with field applied epoxy joints	8.1, 9.7, 10.8	X70	2012
	PL18 (SA Portion)	15,300	92	450	Dual Layer Fusion Bonded Epoxy with field applied epoxy joints	8.1, 9.7, 10.8	X70	2012
Carpentaria Gas Pipeline	PL 41	14,800	840	300	Extruded HDPE “Yellow Jacket” with FBE 10km d/s Ballera and 5km d/s of SS Field applied dual tape joints	6.91, 8.29, 10	X70	1998

Pipeline Name	Pipeline License	MAOP [kPag]	Length [km]	Diameter [DN]	Coating Type	Wall Thickness min, max[mm]	Grade[API 5L]	Year Const.
Cannington Lateral Pipeline	PL 42	9,900	97.5	150	Over-the-ditch Dual Layer HDPE tape wrap	4.13, 4.95, 7.11	X42	1998
Mica Creek Meter Station (MCMS) including Diamantina Power Station (DPS) Off take	PL 50	14,800 (DN150) and 3,300 (DN300)	0.173 0.07	150 300	Dual Layer FBE with field applied tape wrap joints	7.11 6.4	X42	1998
Mt Isa Lateral (MIM)	PL 51	5,100(DN150) and 1,960(DN80)	6.2 0.09	150 80	Extruded HDPE "Yellow Jacket" with field applied tape wrap joints	4.8, 6.4 5.5	X42	1998
Peat Lateral (Woodroyd to Arubial (110.7km), Scotia to Woodroyd (10.7km)	PL 74	10,200	121.4	250	Extruded HDPE "Yellow Jacket" and field applied dual tape wrap joints	4.7 (Main line), 5.7	X60	2001
Kogan North Central Gas Processing Facility (KNCGPF)	PL 120	9,600	0.040	200	Extruded HDPE "Yellow Jacket"	12.7	Grade B	2005
Berwyndale to Wallumbilla Pipeline	PL 123	15,300	112	400	Trilaminate & Heavy Duty application HDPE Heat Shrink Sleeves	8.10 and 9.61	X70	2007

2 PIPELINE STRUCTURAL INTEGRITY

Continued pipeline structural integrity is achieved by implementing pipeline mitigation strategies and protecting the QLD Assets against the following external threats:

- third party damage
- corrosion
- excessively high or low temperature or pressure
- natural events
- ground movement either natural or man-made
- Ensuring that any modifications, maintenance and repair of the pipeline are carried out in a manner that maintains pipeline integrity
- Ensuring the pipeline is not adversely affected by mechanical stresses from operation, e.g. fatigue

2.1 Pipeline Structural Integrity Review

APA utilises a number of methods for analysing the structural integrity of pipelines and relies upon technical data collection and verification, calculation and analysis. Periodic Remaining Life Reviews (RLR) will ensure the pipeline system's failure mechanisms are identified, minimised and rectified in a timely manner.

The PIMP shall be reviewed and updated as required to ensure that it is consistent with pipeline system structural condition. This is achieved through a pipeline structural integrity based review, outlined in the following table (**Table**). Note, this table should be read together with section 7 Integrity Programs of this PIMP.

Table 5 – Review Methods for Structural Integrity

Control Methods and Review Process	Interval	Other Basis
Data Collection and verification		
Coating assessment including DCVG survey	5 to 10 yearly on non-pigged pipelines & sections or as required on pigged pipelines.	Where possible third party pipeline damage has occurred or if required to improve CP or if access for excavation may become impeded e.g. new road crossing.
Cathodic Protection Survey	6 monthly (metro); 1 yearly (rural) with report	AS 2885.3 and AS 2832.1
Inline Inspection Pipeline Report	Subsequent to intelligent (ILI) pig run	Integrity
Ground Movement Surveying	As set out in procedures and maintenance plans	Known areas of unstable slopes or mine subsidence
Hazardous Area Inspection	2 yearly	AS 60079.17,
Maintenance and inspection of station equipment	On-going	AS 2885.3
Maintenance and inspection of rotating plant and equipment	On-going	OEM recommendations, APA Group overhaul philosophy

Control Methods and Review Process	Interval	Other Basis
Plan & Procedural Reviews		
Pipeline Integrity Management Plan (this PIMP)	5 yearly or where new integrity issues have been identified	AS 2885.3
SCC Management Plan	5 yearly or as required	Integrity
Emergency Response Plan (Exercise)	2 yearly	Queensland Legislation
Asset Management Plan	5 yearly	PMS
Corrosion Management Guideline	5 yearly or as required	Integrity
Land Management Plan	5 Yearly	PMS
Pipeline Remaining Life Review		
Remaining Life Review (RLR)	10 yearly	AS 2885.3
Safety Management Study	5 yearly	AS 2885.3 & RLR
Location Class Review	5 yearly	AS 2885.3 & RLR (with SMS)
Isolation Plan Review	5 yearly	With RLR
Pressure Control and Over-Pressure Protection System Review	10 yearly	With RLR
Structural Integrity Calculations		
MAOP / MOP	5 yearly	With RLR
Fracture Control Plan	10 yearly	AS 2885.1 & RLR
Fatigue assessment	5 yearly	With RLR
Pipe wall integrity Assessment	As required	With RLR

2.1.1 Integrity Data Management Tool

APA operates an Integrity Data Management Tool (IDMT). This tool is loaded with the transmission pipeline assets coordinates and details and is updated with all survey and excavation data to provide a searchable and comprehensive record of integrity related work carried out on the asset. The tool provides a GIS output which enables data to be assessed and visualised geographically, generally utilising satellite imagery as a background.

The tool is kept up to date with new data including coating and defect repairs and provides the platform for integrity management. IDMT roll-out is still in progress for QLD assets.

2.2 Pipeline Operation & Control

APA owns and maintains a number of regulating stations and 13 compressor stations as highlighted in **Table 1**

Table 3 - Specification of the Compressor Stations. The stations control and regulate the pressure and flows within the system and are continually maintaining operating parameters in accordance with the design, construction, approved operating requirements, AS2885.1 requirements and GTA pipeline agreements.

Operating parameters are monitored at all key stations. Control of pressures, temperatures and flows are managed within the limits determined by APA for each asset as defined in the Pipeline Management Plan, Design Basis, approved drawings and operating procedures. These controls generally comprise two independent layers; Process Control limits to the operating set points and Rate-of-Change and process Safety System trips within the site controls.

2.2.1 Pipeline Operation Parameters

2.2.1.1 *Process Control and Safety Shut off Systems*

Operating process control capability keeps the pressure and temperature within acceptable pressure and temperature limits. The system ensures both a primary pressure control and a secondary independent pressure limiting system to ensure overpressure protection is in accordance with AS2885.1 requirements.

Over and under-temperature alarms ensure that the temperature of the gas inside the pipeline shall not exceed the design limit of the pipeline as specified in the Pipeline Management Plan.

2.2.1.2 *Operating Temperature*

Certain APA QLD pipelines were constructed and commissioned before the introduction of the AS2885 standard, however by enforcing the Process Control and Safety System the operating temperature within the QLD Assets is managed nominally between a minimum design temperature of -10°C, to limit low temperature brittle failure and a nominal maximum of 60°C. The high operating temperature range is enforced such that the coating temperature rating and thermal stress limits on the pipeline do not become compromised.

Elevated pipeline temperatures on the system can also assist in the formation of some types of SCC. The QLD Assets have a number of older pipelines coated with tape wrap which is susceptible to thermal damage. However these pipelines do not currently experience elevated operating temperatures. There is no compression without after-cooling on any of the QLD pipelines.

SCC is further discussed in detail in Section 3.2 of this PIMP.

2.2.2 Pipeline Control - Compressor Stations

APA Compressor stations are located at Yuleba, Condamine, Kogan, Dalby, Oakey, Gatton, Morney Tank Scraper Station, Davenport Downs, Moomba, Cooladdi (QCS4), Wallumbilla WCS1, WCS2,WCS3 and the Kogan North processing facility.

APA has remote start and stop control and pressure set point control at each compressor station site. The local APA control system Programmable Logic Controller (PLC) determines the allowable operating range whilst the Safety System provides independent process safety trips.

Detail of the compressor station sites can be found in

Table 3.

2.2.3 Pipeline Control - Regulator Stations

Pressures are monitored at all regulator stations. High pressure alarms and trips are made available to APA if pressure limits are exceeded. APA regulator installations are designed to protect a downstream pipeline with a lower MAOP than the upstream pipeline; they are designed to AS 2885 requirements and have at least two levels of protection against overpressure of the downstream pipeline. In addition some stations have more than one regulator run where security of supply is paramount. A typical class break facility will have either a Slamshut (overpressure shutoff valve) or PSV, plus monitor regulator and active regulator in each run.

Where downstream temperature would be unacceptable due to cooling associated with large pressure drops, the facilities include gas heating and low temperature trips.

2.2.4 Pipeline Control Operating Systems

2.2.4.1 *Supervisory Control and Data Acquisition (SCADA) System*

The SCADA system is the primary means of monitoring and managing the QLD Assets. The SCADA host is owned, operated and maintained by APA under the change management procedures. The associated communications infrastructure is also owned and managed by APA, and is designed to carry data for APA. Data interfaces, signal names, storage requirements, polling frequencies and alarm responses shall be specified by APA in the functional specification for each particular Remote Terminal Unit (RTU). The master location for the alarms is currently within the SCADA system however changes to this are managed under the ENG2-03 “Plant Change Procedure”.

All compressor stations, scraper stations, metering stations and other specific equipment are connected by the SCADA system to a Control Centre and monitored 24 hours per day and 7 days per week by Pipeline Controllers. SCADA data from the facilities is returned to the Control Centre via dedicated landlines, Telstra Next G network and satellite links.

In addition to the above, the SWQP system uses a volume based Pipeline Leak Monitoring system configured in the SCADA system to alarm when a defined volume imbalance is experienced in a defined period of time.

Pipeline Controllers continually review data from all sites to ensure each site is operating in conjunction within the specific operational parameters required by APA Group’s Gas Transportation Agreements, manufacturer’s recommendations and the pipeline licences.

Data collected from the various sensing devices at the telemetered sites is monitored and stored on disk and back-up systems.

Initial response to alarm conditions monitored by the SCADA system is handled by Gas Control and “on call” staff while major equipment failures or third party encounters are managed as per the Emergency Response Plan from the Brisbane office.

The QLD Assets operating parameters are highlighted in the Pipeline Management Plan, Chapter 3: QLD Operations.

APA is currently implementing an APA National ALARM Philosophy. The purpose of this philosophy is to provide a consistent approach for the setting of alarms to assist the Pipeline Controllers to respond effectively to each alarm that occurs. It also provides guidance on alarm documentation and rationalisation.

A key outcome of this will be a master register for recording and approving all key alarms on the QLD assets, which will be referenced in this PIMP once approved.

2.2.4.2 *Telemetry Systems*

The monitoring and control system comprises Instrumentation, PLC, and RTU. Communications services comprise a range of Internet Protocol (IP) and serial communications, with linkage to the APA SCADA network using fixed wire communications (BDSL/ADSL), mobile communications (NextG, GSM), and/or Satellite services, which are used either as the primary communications device, or in combinations to provide greater security where required. Sites are rated as gold, silver or bronze based on their criticality and communications security requirements.

The APA Control Room monitors all telemetered facilities.

2.2.4.3 *Backup Communications System*

Backup communications are provided to sites where failure of primary communications could limit the effective operation. The backup communications may be Satellite, GSM connection where PSTN lines are not available.

In case of total failure of the SCADA communications system, certain key sites may require personnel to attend to monitor or control the site subject to gas demand and pipeline line pack conditions. This would be managed under APA's emergency response plans and procedures.

3 PIPELINE CORROSION PROTECTION

3.1 Corrosion Mitigation Strategy

Document 530-GD-E-0001 “Corrosion Management Guideline” is a technical document detailing the process of providing corrosion mitigation for the above ground and below ground assets. This document supports the ensuring that above and below ground assets perform to their engineering design and operating criteria and identifies maintenance requirements, including responsibilities and accountabilities to protect against the threat of pipeline corrosion. .

The Corrosion Mitigation Strategy for the QLD Assets shall include the activities summarised in the subsequent sections, whilst the “Corrosion Management Guideline” provides finer details with respect to above ground and below ground coating and Cathodic Protection systems. The guideline is reviewed on a 5-yearly interval and shall be reviewed immediately after new corrosion threat is identified.

3.1.1 Pipeline External Coating Strategy

External coating is the primary protection for a pipeline.

The purpose of external coating is to:

- Electrically isolate the external surfaces of the pipeline from its environment
- Have sufficient adhesion to resist under-film migration of electrolyte
- Be sufficiently ductile to resist cracking
- Resist damage due to soil stress and normal handling
- Be compatible with cathodic protection
- Resist deterioration due to environment and service temperature

The Queensland assets are externally protected by various means including FBE, tape wrap, trilaminate and factory coated HDPE. These coating systems also vary in age. Joint coating methods are primarily heat shrink sleeves or HDPE tape wrap. All above ground pipe work has a protective coating predominantly to prevent atmospheric corrosion.

Assessment of pipeline coating is discussed further in **Error! Reference source not found.**.

3.1.2 Cathodic Protection Strategy

The QLD Assets use cathodic protection as a supplement to the coating protection for all buried pipelines. The system uses and combination of sacrificial anodes, cathodic or impressed current cathodic protection systems with installation, operation and maintenance complying to AS2832 standard. Cathodic protection system assessments are discussed in details in Section 3.5 of this PIMP.

3.1.3 In-Line Inspection Strategy

Condition based maintenance applied to pipelines is predominately determined by Inline Inspection (ILI) results. In-line inspections are used on pipelines that are piggable to detect pipe-wall thickness loss (internal and external) due to metal loss corrosion, and physical and construction pipeline damage. ILI is also used to detect strain/curvature and dents.

In-Line Inspection is discussed further in Section 4.3. The frequency for Inline-Inspection is outlined in **Table** 9.

3.1.4 Internal Corrosion Strategy

The gas transported is dry sales-quality natural gas and therefore the threat of internal corrosion is not considered credible for the QLD pipelines under current operating conditions. Historical experience including inline inspection has substantiated this assessment as minimal internal corrosion has been detected.

Gas Chromatographs and ancillary equipment are used to measure gas composition and gas quality at injection points and at strategic locations with additional provisions put in place to terminate supply when 'off' specification gas is detected in the pipeline.

Metal loss surveys (ILI) have been utilised in all piggable pipelines to detect internal and external corrosion and in some instances a scrubber pig or cleaning pig have been used to remove dust and debris on affected pipelines.

In addition, some inlet points contain internal corrosion probes which are monitored for internal corrosion.

The frequency for testing and checking of gas quality is outlined in **Table** 10 whilst **Table** 9 outlines the frequency of ILI inspection.

Pipelines that are internally coated are primarily used to improve flow efficiency.

3.1.5 Work Management System (WMS) - Recording and Reporting

APA's Work Management System (WMS) is used to schedule and record the completion of all maintenance work including all corrosion mitigation activities.

Data recording and reporting is an important part of the corrosion mitigation strategy. These records are therefore required as evidence of compliance to the state regulatory authority when requested. This data collection also provides valuable information for identifying corrosion issues over extended periods, as historical data is used to assess and predict metal loss corrosion in the pipeline and appropriately addressing pipeline integrity issues.

3.2 Stress Corrosion Cracking Mitigation Strategy

3.2.1 Stress Corrosion Cracking (SCC)

SCC is the cracking of the external pipe wall induced from the combined influence of cyclic stress, susceptible pipe material, a corrosive environment and in some cases elevated temperature. The impact of SCC on a material usually falls between dry cracking and the fatigue threshold of that material. Cyclic stresses may be in the form of directly applied stresses or in the form of residual stresses.

SCC may be promoted by the following five key areas:

- Elevated pipe wall temperature (in some cases)
- Cyclic stresses and or high operating stress
- Aggressive environmental factors
- pipe wall condition and a prone coating system
- Pipe wall potential in the cracking region

There are different categories of SCC; the main distinction being high pH (classical SCC) or near-neutral pH (low pH SCC). The factors influencing initiation of each type differ slightly thus the method for vulnerability detection varies. The management of the different types of SCC is discussed below.

3.2.2 SCC Assessment of QLD Assets

Most pipelines in QLD have been assessed as having a very low to low risk of being subject to SCC due to design and operating parameters. The exception is the Roma Brisbane Pipeline, which due to its age and coating type has a credible risk of SCC.

Prior to 2011 monitoring for SCC on the RBP system had included ad hoc magnetic particle inspections during opportunistic and corrosion excavations, with no reported evidence of SCC being present on the pipeline.

However, following a severe flooding in South East Queensland in 2011, the RBP was impacted at a number of locations from washout and landslip events which resulted in loss of containment incidents; one in 2011 and one in 2014

The failure analysis conducted in 2014 concluded the root causes of the failure of the pipe were:

- high bending stresses applied to the pipe due to land slippage;
- a pipe material, environment and stress state that were conducive to near neutral pH stress corrosion cracking

The cracks observed originated on the pipe outer surface and were consistent with near-neutral pH SCC. The cracking present was almost entirely circumferentially aligned due to the high loadings imposed by soil movement in the years prior to the landslip event.

While minimal axially aligned cracking has been detected on the RBP system the confirmed presence of circumferential cracking indicates the older tape wrapped sections of the pipeline could be susceptible to axial cracking in areas of stress.

Cracking growth rates are currently unable to be estimated from the Toowoomba failure and applied to the remainder of the pipeline as:

- Stress levels due to soil loading/bending were unusually high; and
- The time of initiation is unknown

3.2.3 SCC Mitigation Strategy

Methods available for investigation and condition monitoring of pipeline segments determined to be susceptible to SCC are:

- In line inspection (ILI) and correlation excavations
- SCC Direct Assessment (SCCDA)
- Opportunistic Excavation and Inspections and
- Hydro-test

In order to provide necessary supporting data, any excavations on APA pipelines where coating damage is present or suspected shall be subject to 100% Magnetic Particle Inspection (MPI) and Ultrasonic Testing (UT) for detection of SCC and crack depth respectively.

In addition to these requirements, APA are developing an SCC Management Plan which will detail necessary activities for inspection and repairs for all known SCC types. Once the plan is implemented this PIMP will be revised and any additional maintenance activities or reviews will be added to the Work Management System (WMS).

The strategies employed by APA include the following:

- XYZ ILI and strain/curvature analysis to identify locations of high bending strain on the pipelines;
- Ground and pipeline survey monitoring in known areas of ground movement;
- Crack detection ILI (UT or EMAT) where practical and justified;
- Other mitigation and management strategies as detailed in the SCC management plan.

3.3 Above-Ground External Coating

Above ground piping is vulnerable to atmospheric corrosion and therefore the surface of the pipeline is protected against the threat by applying a three coat system, a prime coat (first coat) of organic zinc primer, an intermediate coat (second coat) and top coat (third coat) to provide additional mechanical strength and resistance to impact and abrasion.

All above ground coated piping is coated at time of installation. For coating repair and for all new pipework the coating specification shall comply with the SP-M-9602 “Coating for above-ground pipework” specification and AS 2312 “Guide to protection of structural steel against exterior atmospheric corrosion”.

All types of above ground corrosion are mitigated by routine station pipework inspection. These station pipework inspections also address the following specific types of corrosion found at stations:

- Corrosion under insulation resulting from moisture ingress. Spot checks required as part of routine pipework inspections in addition to pressure equipment inspection in accordance with AS3788 and APA’s guideline TP-APAA-104-EG-0043 “Technical Guideline for In-Service Inspection of Pressure Equipment”
- Corrosion at soil to air interface due to a combination of soil stress and moisture ingress and limitations on the CP system at these points

- Crevice corrosion specifically associated with pipe supports, valves and flanges from coating breakdown. Replacement of rusted flange components (studs / nuts) shall be carried out during maintenance work as required.

3.4 Below-Ground External Coating

Coating systems applied to buried pipework on the QLD Assets reflects the advancement in coating technologies and the need to tailor coating systems to specific environmental and physical conditions.

For all below-ground coating of new pipeline and coating repair of existing pipeline the coating assessment and repair shall comply with the SP-M-9601 "Buried Pipeline Coating" specification and at all-time complies with AS 2885.3.

The coating systems on the QLD assets are summarised in Table earlier, which also show the pipeline year of construction to give an indication of the age of the coating.

The below sections only address any QLD pipelines by exception that require specific mention of coating installation or coating condition based on their age or complexity. Some of these may require additional mitigation measures outside of the routine maintenance. Pipelines not included in these subsections generally have good to excellent coating condition as demonstrated by a combination of factors including recent installation, recent DCVG data and low cathodic protection current demand.

3.4.1 RBP – Mainline Original Build (1968-69)

The original DN250 mainline external coating consists of over-the-ditch applied single layer tape polyethylene (PE) wrap. Isolated sections seem to have received multilayer wrapping. This coating is generally in poor to very poor condition with the single layer suspected of passing some degree of cathodic protection current even when well adhered. The coating has been heavily degraded due to factors such as soil stress and high temperature in certain areas. Even in areas not subject to soil stress or high temperatures, the dielectric strength of the tape coating after 45+ years of service is generally very low and CP current demand is very high.

The DN300 "RBP Metro", while the same age as the DN250 pipeline, was constructed with over the ditch applied dual layer PE tape. This coating has been found to be in reasonable to good condition.

The DN200 "SEA Block Valve to Gibson Island Meter Station" was constructed with over the ditch applied dual layer PE tape. This coating has been found to be in reasonable to good condition.

Repair works have been completed with a variety of brands of tape wrap systems and some more recent pipe replacements have been undertaken with alternate coating systems such as factory applied trilaminate or FBE or field applied epoxy. Pipeline alignment sheets and the GIS contain the latest information in regards to coating type at specific locations.

Specific measures are in place for upgrading the coating on the RBP mainline in selected areas, which are budgeted and managed as part of the annual SIB project upgrade program.

3.4.2 RBP – DN400 Mainline Looping (1988-2002)

The DN400 is more complex than it would first appear from an integrity view point. The looping was completed in 7 stages over the period of 14 years. These stages were far from linear in their progression and utilised different pipe grades and field joint coating systems.

Repair works have been completed with a variety of brands of tape wrap system and some pipe replacements have occurred utilising other factory applied coatings. Overall the HDPE ("Yellowjacket") line pipe coating has performed satisfactorily and is consistent with other HDPE-coated pipelines. Typical issues are associated with improperly installed heat shrink sleeve joint coatings, or splitting and cracking of the HDPE at locations of mechanical damage.

The table below (

Table 4) describes the pipeline construction stages in detail.

Table 4 – RBP Mainline Looping coating condition

Stage & Construction Year	Mile point	Coating	Coating condition
Stage 1 - 1988	0-6, 31.3-40.4, 78-86.05, 117.5-126, 161.1-172.4,	Extruded High Density Polyethylene(HDPE) with Canusa Heat Shrink Sleeves	Generally good except where sleeves have disbonded
Stage 2 – 1990	25.3-31.3, 67.4-78, 126-135, 200.97-217.5,	HDPE with heat shrink sleeve joints	Generally good except where sleeves have disbonded
Stage 3 – 1998	40.4-54, 100.5-106.27, 152.8-161.1, 172.4-178	HDPE with PE tape wrap joints	Generally good
Stage 4 – 2000	6-14, 147.24-152.8, 178-189, 237-344.3	HDPE with PE tape wrap joints	Generally good
Stage 4B – 2002	217.5 -224	HDPE with PE tape wrap joints	Generally good
Stage 5 - 2002	14-25.3, 54-67.4, 86.05-100.5, 106.27-117.4, 134.4-147.24, 189-200.97, 224-236.97, 244.3-245.6, Swanbank Lateral	HDPE with P tape wrap joints	Generally good
Stage 6 - 2002	Collingwood Ellengrove Pipeline	HDPE with PE tape wrap joints	Excellent

3.4.3 South West Queensland Pipeline (SWQP)

The original DN400 “South West Queensland Pipeline” was commissioned in 1996 utilised a Fusion Bonded Epoxy coating of no less than 400 micron on the line pipe with field applied epoxy used for the field joints. The coating of the line is in excellent condition as indicated by the good DCVG result obtained in 2009.

The DN450 South West Queensland Expansion” (SWQE) pipeline was commissioned in 2012 as part of the QSN3 project featured a 800 micron dual layer FBE coating for line pipe and 1250 micron FBE for HDD pipe and liquid epoxy for induction bends.

While a DCVG was completed on the DN450 pipeline post construction the report was severely lacking in detail and found no defects despite two defects being identified by a separate survey at the Warrego River HDD location. This raises questions about the quality and completeness of the DCVG survey.

Overall, given modern construction practice it would be expected that the coating of the loop line would be in very good condition. This is difficult to confirm due with the lack of a reliable DCVG report due to the way the CP systems between SWQP and SWQE are tied together. Based on total output current and previous CP currents for the SWQP it can be assumed pipe coating is very good to excellent.

3.4.4 Below-Ground Coating Survey

Protective coating on buried structures often contains defects once it is buried. Handling during construction can cause damage to coating, which can also be damaged by soil movement and stress factors once in operation. As much as possible, this is mitigated by construction QA including holiday testing of the coated pipe at several stages including before lowering in.

Condition of pipelines is typically assessed by ILI (refer to the National APA Coating Assessment Policy). Overall coating condition is tracked by monitoring CP current demand. In addition, the CP system is providing corrosion protection regardless of coating damage. Routine DCVG surveys are not undertaken on piggable pipelines.

APA utilises coating defect surveys such as Direct Current Voltage Gradient (DCVG) on some pipelines (or sections of pipelines) which are un-piggable, when a pipeline is suspected to have been damaged due to excavation work, or as otherwise required (such as prior to construction of a road over the pipeline which would limit future access for repairs).

Where significant coating defects have been identified from a DCVG survey, pipeline validation digs at selected locations shall be carried out to assess the pipe wall and the coating damage, followed by coating repair.

Currently DCVG surveys are conducted on all un-pigged pipelines and pipeline sections and the scheduling and completion completion of the survey is managed via the WMS as outlined in **Error! Not a valid bookmark self-reference.**10 below lists all routine maintenance activities currently undertaken by APA Group in relation to maintaining pipeline integrity for QLD assets.

Table 10.

3.5 Cathodic Protection System

3.5.1 Cathodic Protection System Operation

Cathodic protection systems are operated and managed in accordance with the "Corrosion Management Guideline", AS 2885 and AS 2832. Specific guidance on operation is further defined in Section 6 of this guideline and section 10 of AS 2832.1, which includes the following areas:

- System operation checks
- Structure inspection
- Cathodic protection survey and
- Interference testing

Competent corrosion technicians are engaged to carry out appropriate tests to determine the adequacy of the cathodic protection system; these tests include but are not limited to the following:

- Monitor cathodic protection unit operation by remote monitoring where practicable and by pipeline operator inspection at all non-monitored sites.
- In areas where structures are affected by traction stray current, nominal 24 hour recordings at 10 second intervals are taken at all test points.
- For all non-traction stray current pipelines On/Off potential measurements are taken at every test point with nominal 24 hour recordings taken as required to assess telluric activity and other extraneous events.
- Monitor stray current drainage bonds and confirm operation of drainage bonds
- Measure and determine foreign CP system interference through routine monitoring and coordinated interference testing.
- Measure decoupling device performance and earthing bed resistance

Cathodic protection inspections and surveys are carried out in accordance with APA QLD procedures and work instructions and as set out in the maintenance management system.

Cathodic protection technicians shall be equipped with the correct tools and equipment to adequately carry out cathodic protection surveys. CP equipment shall be maintained within APAs internal register and the record shall be kept at the relevant operational sites. Cathodic protection equipment shall be calibrated and maintained in accordance with AS 2832.1. For a full listing of the CP equipment listing refer to Table 8 of the "Corrosion Management Guideline".

The personnel responsible for the monitoring and maintaining cathodic protection on the QLD Assets is defined in Section 2.2 of the "Corrosion Management Guideline".

Any rectification work required shall be implemented through the WMS, and the frequency for carrying out cathodic protection work is outline in **Error! Not a valid bookmark self-reference.**10 below lists all routine maintenance activities currently undertaken by APA Group in relation to maintaining pipeline integrity for QLD assets.

Table .

3.5.2 Cathodic Protection System Details

QLD uses predominantly impressed current cathodic protection systems and stray current drainage in traction affected areas to provide cathodic protection in accordance with AS2832.1. 6 pipelines are protected using sacrificial anodes.

Generally station underground pipework and vent lines are grouped together and protected by sacrificial anodes.

Further details of cathodic protection systems for each asset are detailed in the sub-sections below.

3.5.3 Roma Brisbane Pipeline and Laterals

The RBP mainline from Wallumbilla to Swanbank (DN400) and Bellbird Park (DN250) is protected by an impressed current system with cross bonds between the DN250 and DN400. They system comprises of 69 units ranging from 25Amp to 80Amp capacity with a total system operating output exceeding 1400 Amps. Many of these units are quite old and operate near their maximum capacity with unit failure not uncommon. As such the fortnightly Transformer Rectifier Unit checks are critical to maintain the systems operation. An ongoing CP Upgrade programme includes replacement and upgrade of TR units, anode beds and associated equipment, as well as construction of new CP sites. New CP sites are required from time to time to maintain protection as current demand increases due to coating deterioration.

The Redbank to Swanbank laterals were designed to be protected by a combination of magnesium anode and zinc earthing. However, these magnesium anodes have since been disconnected and the system has been bonded to the 16" mainline at Redbank station. The zinc earthing remains connected to combat AC pickup.

The Collingwood to Ellengrove lateral was split into a number of electrically short sections during construction with buried insulating flanges and a bed of sacrificial zinc anodes at the midpoint of each section. This design was adopted due to the line sharing its easement with high voltage power along the majority of its length.

The "Brisbane Metro" section from Bellbird Park utilises impressed current cathodic protection provided by two 20V / 10 Amp CP units capable of operating in auto potential mode. This system is bonded to the DN200 from SEA to Gibson Island.

The Lytton Lateral Pipeline is electrically isolated from the other sections of the RBP and uses two sacrificial magnesium anode beds to provide cathodic protection.

The RBP Metro looping 1 pipeline is currently cross bonded to the DN300 line at the Preston Rd valve pit and at the Paringa Rd Station in Murarrie.

Refer to CP Schematics RB-PL-GEN-C-001 and RB-PL-GEN-C-002 for further details.

3.5.4 Peat Lateral Pipeline

The Peat lateral Pipeline is protected via three sacrificial anode beds between Woodroyd and Arubial stations. The Scotia to Woodroyd extension is protected by a single sacrificial anode bed.

CP problems are sometimes experienced on this pipeline due to liquids from upstream production facilities entering the system and bridging insulating joints. This is currently managed by cleaning pig runs.

3.5.5 Carpentaria Pipeline

The CGP was originally built and commissioned to be protected via solar powered impressed current Cathodic Protection systems at each scraper station. However, the installed units proved ineffective at operating at the very low outputs required by the pipeline. The pipeline was then retrofitted with 2 sacrificial magnesium anode installations per section, except for Section 1 which only has 1 magnesium anode bed.

Impressed current CP systems are operational at Mica Creek and Trekelano in Section 6 of the CGP, in order to counter telluric current effects. The remaining 5 sections are all satisfactorily protected by sacrificial anode systems and the original ICCP systems have been switched off.

Refer to CP Schematic BI-PL-PCP-C-014 for further detail.

3.5.6 Cannington Lateral

The Cannington Lateral pipeline is protected by three galvanic (sacrificial) magnesium anode beds.

3.5.7 Mica Creek Meter Station and Laterals

The underground pipework at MCMS is protected by galvanic (sacrificial) magnesium anodes. The various laterals and offtakes are also individually protected by galvanic systems. These include the Mica Creek Power Station DN300 pipeline, Diamantina and Leichhardt Power Station Laterals, the MIM/Mt Isa Lateral and the X41 Lateral.

3.5.8 Kogan North Gas Processing Facility

Due to the very short underground length of the Kogan North export pipeline to the RBP, cathodic protection is provided by a single sacrificial anode.

3.5.9 South West Queensland Pipeline (SWQP) and SWQ Expansion (SWQE)

The South West Queensland Pipelines DN400 (SWQP) and DN450 (SWQE) are protected via SCADA monitored, impressed current cathodic protection systems located at Scraper Stations 1-7 and MLV 1 and 8.

Each scraper station is equipped with a pair of CP units. Due to the method of pipeline looping, odd number scraper stations have effectively been converted to main line valve stations. At even numbered scraper stations this results in one CP unit outputting to the East on both pipelines (SWQE & SQWP) while the other outputs to the west on both pipelines. At the odd numbered stations which now act as MLVs, each CP unit outputs to one pipeline only (either the SWQP or SWQE), both east and west of that location.

The unit located at MLV 1 is only connected to the SWQP, outputting east and west of the MLV, while the unit at MLV8 outputs east and west to both SWQE and SWQP via a cross bond at the station.

Refer to CP Schematics Q-01-103-C-001 and Q-01-103-C-002 for further detail.

3.5.10 QSN Link and QSNE (QSN Loop)

The QSN and QSNE pipelines share the Cathodic Protection system originally designed and installed for the QSNE line. This system features 3 impressed current cathodic protection systems, one each located at Ballera, MLV-102 and Moomba.

Refer to CP Schematic Q-02-102-C-003 for further detail.

3.5.11 Berwyndale to Wallumbilla Pipeline

The BWP is protected by an Impressed Current Cathodic Protection system located at Dulacca South about midway of the pipeline. The operating system current is normally less than 10 mA and has adequately Cathodic Protection.

4 PIPE WALL INTEGRITY

4.1 Pipe Wall Thickness

The QLD pipelines are constructed from pipe with differing wall thicknesses depending upon the installation location of the pipe. In general a thicker wall pipe is adopted for roads, railways and bores and other higher risk and stress areas with significantly thicker material for above ground pipe work and downstream of the scraper stations. Sufficient pipe wall thickness is maintained in all pipelines at all locations to contain the gas at the MAOP or at reduced pressures where a MOP restriction is in place. MAOP/MOP is assessed in line with managing operating condition changes in section 9 of this document.

4.2 Corrosion Growth Rate and Corrosion Inspection

Corrosion growth rate estimation shall be undertaken and documented for all pipelines with reported or confirmed metal loss. As a minimum a mean and maximum growth estimate will be established.

All piggable pipelines will be inspected for internal and external corrosion through the use of Magnetic Flux Leakage (MFL) In-line Inspection as a minimum. Where previous MFL inspection information is available a corrosion growth assessment will be completed by the inspection vendor based on magnetic flux profile comparison techniques.

Where no previous inspection has been performed the corrosion growth rate may be estimated from inspection findings and tolerances in consultation with suitable literature and previous experience (where applicable). Corrosion growth based on reported feature depths divided by total service time may be conservative and consideration should be given to the use of an incubation period for initiation.

Where a depth growth rate has been established, length growth may be estimated by applying constant defect length and depth ratio.

4.3 In-Line Inspections

In-Line Inspections (ILI) are utilised to determine the integrity of each piggable pipeline in accordance with the APA pigging policy and national schedule. The purpose of ILI is primarily to assess the pipeline wall thickness metal loss resulting from corrosion of the steel pipe and mechanical damage using MFL and geometry (caliper) tools. ILI is also used for assessing centreline changes and associated strain events using XYZ (inertial) tools. In-Line Inspection is always contracted externally to a third party pigging operator who provides the hardware 'intelligent pig' and software data analysis to determine the pipeline anomalies and wall thickness metal loss.

When an ILI survey has been completed a detailed report of the ILI inspection is submitted to APA for review and to determine pipeline validation dig requirements.

Typically the Inline Inspection frequency is dependent on the following criteria:

- Determined interval based upon State Regulations
- Pipeline Remaining Life Review
- Assessing special integrity concerns
- Pipeline base-line surveying and corrosion growth rate
- Previous corrosion anomaly defect assessment and detection

ILI frequency is approved in accordance with the Approval Matrix and nominated in the Asset Management Plan. Details of the current QLD pipeline Inline Inspection frequencies can be found in **Table** along with the basis for the inspection interval.

4.4 Un-Piggable Pipelines

There are currently three (3) pipelines that are unpiggable within QLD. In addition, there are a number of sections of underground pipelines that are unpiggable (including offtakes).
Unpiggable lines are assessed in the SMS for each pipeline and current philosophy is to ensure that these lines undergo DCVG at a 5 yearly frequency in the short-term. This frequency will be assessed once recent survey data is evaluated and will be revised in the WMS. These are also managed in conjunction with CP monitoring and direct assessment as required.

4.5 Pipeline Material and Construction Anomalies

All material and construction anomalies shall be assessed at the time of construction of the pipeline for their effect on the short term and long term integrity. Any anomaly deemed detrimental to the operation or the performance of the pipeline shall be repaired or replaced as required.

All material and construction anomalies located during operation or maintenance of the pipeline will be assessed at the time of finding, and appropriate corrective action shall be determined.

All pipe wall repair techniques will be determined for each type of damage with the pipe wall anomaly assessment in Section 4 of this PIMP.

4.6 Pipeline Joints

The integrity of pipeline welded joints is managed by the ILI surveys and associated excavation programs. Pipeline joints shall be inspected by Non Destructive Examination (NDE) methods when a joint is exposed at selected location during pipeline validation dig.

4.7 Ground movement

There are some pipeline sections within the QLD assets that are exposed to ground movement. The majority of these sections are on the RBP and there have been a range of emergency works triggered by heavy rainfall events during the period from 2011 – 2014. In addition to mechanical damage impacts on the pipelines, these events pose risks to the pipeline at high strain locations.

To mitigate these risks an in line inspection with XYZ inertial mapping tools including a strain/curvature analysis to identify where bending is imposed on the pipeline. Strain change analysis can also be undertaken by comparing XYZ data from sequential runs, to identify where the curvature / bending shape has changed in between pig runs. These locations are included in the pipeline excavation listing and program for assessment and repair as required.

There are also some pipelines in the QLD assets that are susceptible to mine subsidence, mainly in the Ipswich region where numerous old underground coal mines exist. These sections have survey monitoring points installed to measure movement and these points are surveyed in accordance with the WMS planned maintenance frequency. Two locations on the Swanbank Lateral pipeline are installed beneath inverted culverts to allow flexibility; these are routinely inspected as a planned maintenance task. Long-term underground coal fires are known to be present in some areas and APA has installed underground temperature probes which are also routinely monitored. Strain analysis will also be employed where appropriate for these segments.

In addition to the high strain locations, the Toowoomba Range rail crossing has suffered containment failures in both 2011 and 2014 due to landslips. A reduced diameter crossing has been installed inside the DN250 pipeline at this location, until approvals are in place for a permanent replacement DN250 crossing.

A land stability management plan is being developed to specify any additional monitoring that will be required in the Toowoomba range, and this will include guidance on actions that will be required to be taken once monitoring data is reviewed.

4.8 Leakage Detection

APA deploys a number of methods to detect gas leaks in buried pipeline and above ground pipework within the QLD Assets. The most common methods used are ground and aerial patrolling of pipeline from external interference. As detailed in SCADA section 2.2.4.1 of this document, the SWQP SCADA system also operates with a leak detection system.

APA utilises a pipeline patrolling system to ensure adequate monitoring of the pipeline corridors. Pipeline patrols shall include the identification of external interferences resulting in a pipeline gas leak due to pipeline damage caused from heavy machinery excavation work, or through an unlikely occurrence of a pipeline gas leak caused from an integrity issue.

Ground patrol and aerial surveillance are used to identify signs of pipeline leakage in addition to the leak surveys carried out annually.

As part of the routine maintenance of mainline valves, pit sites and above ground pipework and equipment shall be gas leak tested using specialised gas detectors and snoop testing equipment.

All Leakage detection activities are highlighted in **Error! Not a valid bookmark self-reference.**10 below lists all routine maintenance activities currently undertaken by APA Group in relation to maintaining pipeline integrity for QLD assets.

Table 10.

Odorising of natural gas is only undertaken at MCMS in Mt Isa and Lytton Meter Station in Brisbane, for delivery of odorised gas to specific customers. Most gas in the APA QLD transmission pipelines is not odorised.

5 INSPECTION AND MAINTENANCE PLAN

This PIMP is the basis for the creation of the pipeline maintenance activities related to pipeline integrity; it provides the necessary requirement for routine and non-routine pipeline inspection associated with a pipeline asset as outlined in **Error! Not a valid bookmark self-reference.**10 below lists all routine maintenance activities currently undertaken by APA Group in relation to maintaining pipeline integrity for QLD assets.

Table 10.

5.1 Inspection Record and Location

The Works Management System (WMS) is the main repository of all routine maintenance inspection results. The result of completed maintenance work shall be entered into the maintenance database. In some instances pipeline inspection results are submitted to the team leader or managers for reporting purposes, the data and report document shall be kept on the local server typically within the pipeline Integrity folder.

Each pipeline maintenance activity within the Computerised Maintenance Management System (CMMS) contains comprehensive information linking with the resources required for the job such as trade, personnel, maintenance procedures and work instructions and the estimated duration for the tasks.

The maintenance system classifies all assets according to a hierarchy and contains a complete history of when a maintenance task is required.

A review of an existing operating and maintenance procedure is normally carried out when a plant change is required and it shall include the design parameters, control, design documentation for the plant and its equipment. Therefore reviews of the operating and maintenance procedures are carried only when required. By default, most QLD procedures and work instructions are set for 5-yearly reviews.

Maintenance procedures and work instructions were created for each asset during design and prior to putting the pipeline into operation. These procedures and work instructions are controlled documents that can only be changed by formal change management processes and will require management approval through the 320-MX-AM-0001 “Approval Matrix” prior to implementation.

5.2 Frequency of Inspection

The frequency of inspection of each pipeline inspection activity is determined by a number of factors, they may include but not be limited to the following:

- Statutory requirements
- Historical data records
- Current knowledge of their condition
- The rate of deterioration (both internal and external corrosion, and coating degradations)
- And review and implementation of this PIMP

Pipeline inspection frequency shall be carried out as outlined in The tables in this section document the activities undertaken by APA Group to monitor and manage integrity of QLD pipelines.

Table 8, **Table** 9, and **Error! Not a valid bookmark self-reference.**10 below lists all routine maintenance activities currently undertaken by APA Group in relation to maintaining pipeline integrity for QLD assets.

Table 10.

6 EXTERNAL INTERFERENCE MANAGEMENT

6.1 General

External interference is one of the biggest threats to the QLD Assets and APA applies significant resources towards minimising this threat.

External interference threats can arise from third party property owners, contractors, other service authorities, changing land use around the Right of Way (ROW) and other pipeline operators.

A separate nationalised land management plan found in 320-PL-HEL-0001 "Land Management Plan" has been developed to manage pipeline external interference threats. The entirety of the plan was created in accordance with Section 7 of AS 2885.3.

For full coverage of external interference management, the plan shall be read in conjunction with the subsequent sections.

The SMS process (addressed in Section 9.2 of this document) is the primary process for identifying and assessing these threats and as a result generates actions for any increased mitigation on top of existing procedures as required.

6.2 Third Party Pipeline Awareness

APA shall implement a third party awareness program designed to inform stakeholders of specific obligations that is required when working in the vicinity of the QLD Assets.

Three key areas highlighting the pipeline awareness program includes:

- APA awareness program (stakeholder, landowner, emergency services, landowner complaints and unauthorised works)
- Placement of pipeline markers and
- Easement data

6.3 External Interference Detection

APA utilise a pipeline patrolling system to ensure adequate monitoring of the easements which include the following:

- Pipeline aerial surveillance
- Pipeline ground patrolling
- Land use change identification through Location class review and assessment

6.4 External Interference Control

APA implements the external interference control program to appropriately manage external interference threats which include:

- Dial Before You Dig (DBYD)
- Third party work authorisations
- External interference guidelines (easement maintenance, easement access, restricted activities encroachment on the pipeline corridor, unauthorised works and future encroachments).

There are a number of procedures that support this program that are referenced in the Land Management Plan.

7 STATION OPERATIONS AND MAINTENANCE

Station operation and maintenance is conducted on a risk based routine to ensure they operate within the limits of their design. This section of the PIMP describes in some detail the station's asset maintenance activities, whilst the **Error! Not a valid bookmark self-reference.**10 below lists all routine maintenance activities currently undertaken by APA Group in relation to maintaining pipeline integrity for QLD assets.

Table 10 detailing the station's maintenance inspection checks and frequencies.

Records of all inspection and maintenance activities are kept in the WMS or at the appropriate local drive.

7.1 Safety Critical Equipment

Systems that were designed with a minimum Safety Integrity Level (SIL) requirement under AS61511 will be maintained as per the designed parameters, with particular attention to routine functional safety testing and operator training. The equipment is incorporated into the maintenance plan and shall be maintained in accordance with the manufacturer maintenance recommendations. These systems can range from:

- Basic electric, pneumatic or combination 'hard-wired' devices;
- SIL-rated safety relays and/or devices; and
- SIL-rated safety PLCs.

Gas compressors and some specialised gas processing units (such as TEG units and heaters) come under the AS3814 definition of a 'Type B' appliance and require additional safety verification and maintenance to remain compliant.

7.2 Pressure Vessels

Pressure vessels are adequately maintained and routinely inspected with external inspection being carried out on a 2 yearly interval and internal inspection carried out on a 4-yearly interval as indicated in **Error! Not a valid bookmark self-reference.**10 below lists all routine maintenance activities currently undertaken by APA Group in relation to maintaining pipeline integrity for QLD assets.

Table 10.

Scheduling of vessel inspections is co-ordinated through the WMS with inspection procedure created to comply with AS 3788 'Pressure Vessel – In Service inspection' and APA's TP-APAA-104-EG-0043 'Technical Guideline for In-Service Inspection of Pressure Equipment'. Corrective actions are addressed as follow up work orders.

7.3 Station Operation Checks

All above ground pipe work and equipment is routinely inspected and maintained to ensure it remains fit for purpose and is operating within the limits of the process design.

Station operation checks are conducted and scheduled in the WMS for control equipment including electrical, mechanical and piping equipment including cathodic protection system.

Safety valves and devices used for pipeline isolation and during an Emergency Response are maintained as part of station maintenance work and are regularly tested. The frequency of station operation check can be found in **Error! Not a valid bookmark self-reference.**10 below lists all routine maintenance activities currently undertaken by APA Group in relation to maintaining pipeline integrity for QLD assets.

Table 10.

7.4 Station Structural Integrity

7.4.1 Pipe Supports

Pipe supports provide structural stability to components including pipe work, pig traps, piping valves and filters. Pipe supports are routinely inspected as part of the general facility inspection program. Ongoing maintenance activities such as repair or replacement are performed as required.

The design of some pipe supports prevents the full inspection of the piping they support and could be subject to hidden corrosion over time. This is monitored and addressed as part of the station inspections and raised with Engineering Services for closeout.

Pipe supports will be inspected during routine valve station and site inspections and maintenance. The frequency of station pipe support inspection can be found in Error! **Not a valid bookmark self-reference.**10 below lists all routine maintenance activities currently undertaken by APA Group in relation to maintaining pipeline integrity for QLD assets.

Table .

7.4.2 Station Piping

Station pipework incorporating pipe, reducers, elbows and flanges are regularly inspected for indication of atmospheric corrosion.

Corrosion on piping at the interface between below ground and above ground is the main focus during station piping inspection due to the potential for corrosion caused by water ingress between the interfaces.

There is an ongoing painting program on QLD sites. These are determined by Operations inspections and budgeted in the Asset Management Plan as a major opex item.

Cathodic protection systems are installed to protect all buried pipeline assets including station buried piping. The cathodic cathodic protection is achieved via cross bonding the buried structure to the CP system. All buried station piping is incorporated into the routine cathodic protection survey and the unpiggable pipe coating assessment surveys outlined in outlined in **Error! Not a valid bookmark self-reference.**10 below lists all routine maintenance activities currently undertaken by APA Group in relation to maintaining pipeline integrity for QLD assets.

Table 10.

7.5 Compressors

7.5.1 Gas or Diesel Engine Alternator (GEA or DEA)

Maintenance requirements have been developed for all rotating plant based upon the manufacturer recommendations and scheduling is implemented in WMS detailed in Error! **Not a valid bookmark self-reference.**10 below lists all routine maintenance activities currently undertaken by APA Group in relation to maintaining pipeline integrity for QLD assets.

Table . All compressors and turbines are overhauled based on the number of hours of operation and condition monitoring as determined by the rotating engineer.

7.5.2 Gas or Diesel Engine Alternator (GEA or DEA)

Gas Engine and Diesel Engine Alternators are employed at various APA sites for either primary or backup power generation. Where installed, each engine and electrical equipment is maintained in accordance with manufacturer recommendations.

GEAs and DEAs are maintained in accordance with the station's maintenance frequency detailed in **Error! Not a valid bookmark self-reference.**10 below lists all routine maintenance activities currently undertaken by APA Group in relation to maintaining pipeline integrity for QLD assets.

Table 10. All GEAs and DEAs are overhauled based on the number of hours of operation and condition monitoring as determined by the rotating engineer.

7.6 Valve Station Security

Valve station security inspections and checks are performed in accordance with the station's maintenance activities detailed in **Error! Not a valid bookmark self-reference.**10 below lists all routine maintenance activities currently undertaken by APA Group in relation to maintaining pipeline integrity for QLD assets.

Table 10.

All stations are secured within a fence and a locked compound displaying identifying signage. The fence structure is typically a two metre high cyclone mesh fence with triple row barbed wire topping. A minimum of two access points are provided, at least one of which is a double vehicle gate. All gates are padlocked closed when the site is unmanned.

Chain link fences shall be inspected for rust and general wear and tear as part of the routine site inspections. Replacement fencing deemed as a safety and security concern shall be secured as a priority.

Critical manual valves are locked in position as shown on P&IDs to prevent interference and all above ground facilities are monitored on a regular basis and complete station checks performed.

All hard standing of compounds are inspected to ensure they provide a stable surface on which personnel can safely conduct their work.

7.7 Station Equipment & Components

7.7.1 Valves, Regulators, Actuators & PSVs

Isolation valves including actuated and non-actuated line, branch and station valves are maintained in accordance with the with the station's maintenance frequency activity detailed in **Error! Not a valid bookmark self-reference.**10 below lists all routine maintenance activities currently undertaken by APA Group in relation to maintaining pipeline integrity for QLD assets.

Table 10.

Actuator spares are readily available. All site gauges have safety glass fitted and are changed if they turn opaque with time.

Regulators on the QLD Assets limit pressure excursions beyond set limits. The devices are maintained in accordance with with the station's maintenance activities detailed in **Error! Not a valid bookmark self-reference.**10 below lists all routine maintenance activities currently undertaken by APA Group in relation to maintaining pipeline integrity for QLD assets.

Table 10.

7.7.2 Pig traps, Launcher Enclosures

Pig traps and launcher enclosures are maintained as part of the above ground piping inspection as detailed in **Error! Not a valid bookmark self-reference.**10 below lists all routine maintenance activities currently undertaken by APA Group in relation to maintaining pipeline integrity for QLD assets.

Table 10.

Scraper facilities are routinely checked and are fully serviced prior to the commencement of an ILI operation.

Pig traps and launcher enclosures are inspected for safety and functionality and to ensure they achieve a gas tight seal.

7.7.3 Gas Quality

Gas quality measurement ensures the gas entering the QLD Assets is within the limits set and monitored by APA.

Gas Chromatographs and ancillary equipment measure gas composition and gas quality at injection points and at other strategic locations of the QLD Assets. Gas quality measurements are also undertaken by third parties for some sites where inlet stations do not have a full suite of analysis equipment or where confirmation of internal APA measurement is required.

The maintenance frequency of the gas quality facilities can be found in **Error! Not a valid bookmark self-reference.**10 below lists all routine maintenance activities currently undertaken by APA Group in relation to maintaining pipeline integrity for QLD assets.

Table 10.

7.7.4 Metering

APA owns and operates numerous custody transfer metering stations, located at most receipt and delivery points on the QLD Assets which comprise a number of different meter types requiring different levels of planned maintenance.

APA metering stations are designed to operate up to the MAOP of the respective pipelines. Calibration and maintenance maintenance checks are performed on a routine basis, the frequency for carrying out checks and calibration of meter can can be found in **Error! Not a valid bookmark self-reference.**10 below lists all routine maintenance activities currently undertaken by APA Group in relation to maintaining pipeline integrity for QLD assets.

Table 10. In addition to the meter types, the drivers for these frequencies are also dependent on the Gas Transportation Agreements in place for the pipelines.

7.7.5 Ancillary Station Equipment

Ancillary gas processing equipment exists at some stations and includes Water Bath Heaters and TEG (Tri-Ethylene Glycol) moisture removal equipment. This equipment is maintained in accordance with AS3788 requirements and the frequency is managed through planned maintenance in WMS – refer table 10.

7.7.6 Electrical Equipment in Hazardous areas

Every site with above ground pipework with potential sources of release is considered a “hazardous area”, under the AS60079 series of standards and regulated by the Queensland Petroleum and Gas (Production and Safety) Act and Regulation. Every electrical device in the hazardous area must comply with the standard, including the implementation of the appropriate protection techniques and regular inspection regimes. For each site, there will be:

- Hazardous area design documents and drawings, detailing the extent of the hazardous area.
- A hazardous area verification dossier, including a register of electrical equipment and their protection techniques;
- Regular inspections (two yearly) to ensure the protection techniques have been maintained.

7.7.7 Control Systems Equipment

Reliability and testing on control systems and instrumentation will be ensured through the means of regular maintenance and inspections. This testing will cover the accuracy and reliability of all electrical transmitters, control valves and overpressure protection systems (such as high pressure and low temperature trips).

- A limited inspection is typically on a fortnightly or monthly regime, with a thorough testing procedure on an annual schedule. These frequencies can be reduced if a design assessment requires a more frequent testing. Separate testing regimes will be implemented for targeted systems, including: Fire suppression systems;
- Function safety systems (refer section 7.1);
- Fiscal Metering devices (refer section 7.7.4);
- Complex analytical devices, such as gas chromatographs and moisture analysers (refer section 7.7.3); and
- Power and Battery systems.

8 ANOMALY ASSESSMENT AND DEFECT REPAIR

8.1 General

Pipe wall anomaly assessment and defect repair shall be carried out to maintain the pipe wall integrity. As documented in the PIMP, pipeline sections are inspected, assessed and repaired as required. Where the pipe wall integrity has been compromised, immediate steps are taken to prevent loss of containment until full integrity of the pipeline is restored. The subsequent section describes in detail how APA manages pipe wall anomaly assessment and repair.

8.2 Pipe Wall Anomaly Assessment Methodologies

8.2.1 ILI Anomaly Assessment

In-Line Inspection shall be used to detect and assess the following pipeline anomalies:

- Corrosion metal loss anomaly through Magnetic Flux Leakage (MFL) tools
- Gouges and dent anomaly through MFL and caliper tools
- Some cracking including girth-weld anomaly (if specified in SMS as a credible threat)
- Note: there are specialised ILI tools available for SCC detection which will be stipulated by the SCC Management Plan as required

The validation and assessment of an ILI pipe wall anomaly will be assessed as part of the pipeline In-Line Inspection program. Upon an internal review of the ILI report a Remaining Life Review may be undertaken to assess the pipeline integrity. All ILI anomaly assessments shall be carried out in accordance with APA's 'Assessment of metal loss results from metal flux leakage In-line Inspection Policy'.

Refer to section 4.4 above for further details.

8.2.2 Fitness for Purpose (FFP) Anomaly Assessment

Pipeline anomalies are monitored through follow-up excavation and inspection of the pipeline at the anomaly location and shall be assessed in accordance with section 9.5 of the AS 2885.3 standard.

8.2.2.1 *Anomaly Assessment Level*

The pipe wall condition will be measured using approved and industry accepted assessment methods. Typically a Level 1, 2, or 3 engineering assessment shall be used in assessing pipe wall anomaly. All anomaly assessments shall be carried out in accordance with section 9.5 of AS 2885.3 and APA-TR-3469 "Assessing Corrosion on Pipelines".

8.2.2.2 *Personnel*

All engineering assessment methods shall be approved and carried out by competent personnel or under the guidance of competent personnel as outlined in the 530-GD-E-0001 "Corrosion Management Guideline".

Competent engineer who is qualified to conduct a level 1, 2 or 3 anomaly assessments are designated by engineering management.

8.2.3 Maximum Operating Pressure (MOP) Restriction

Pipeline anomalies may require a reduction in the pipeline operating pressure to maintain safe operation. These QLD restrictions are in place to ensure safety in pipeline operation whilst the pipeline anomalies are under management. MOPs are approved and implemented formally through the MOP Change Procedure ENG 1-22.

The adjustment of a MOP is a short-term practice for dealing with a 'managed situation' involving a known or anticipated defect or temporary modification to operating conditions.

The following practices are adopted for managing MOP:

- For managed defects on a pipeline, temporary MOP reductions will be considered with the requirement to ensure safe operation of the defect(s)
- Location specific risk is considered in relation to defect failure mode and suitable MOP and repair strategies developed
- Where MOP's are in place, annual reviews are completed and documented
- Where defects are deemed to be permanent and are not actively managed, they become part of the risk profile and are dealt with by a RLR.

8.3 Defect Repair Methodologies

Pipeline repair is conducted in accordance with section 9 of AS 2885.3 and the process detailed under PMS Element 12.

Repair requirements are selected to suit the assessed defect as above. Alternative repairs are assessed and approved utilising the industry recognised PRCI repair manual and all repairs are approved in accordance with the Approvals matrix. Refer to the APA technical guide APA-TR-3469 "Assessing Corrosion on Pipelines" within the PMS for further information.

All repair techniques shall be determined for each type of damage and the repair method can either be temporary or permanent. If a temporary repair has been chosen due to time constraints or potential loss of supply (including cost and implications), a permanent repair shall be followed as soon as possible and subject to a specific risk assessment.

9 OPERATING CONDITION CHANGES & REMAINING LIFE REVIEW

9.1 Changes of Operating Condition

9.1.1 Design Condition Changes

Design condition changes shall be subject to an assessment in accordance with the Engineering plant change procedure ENG2-03. Design condition changes may require the modification of the:

- Operating, maintenance and emergency procedures
- MAOP and
- Remaining life review.

The assessment shall include a review of the following:

- The primary and secondary location class of all pipeline;
- Management of risk to the public, property, environment or to the pipeline system in accordance with AS 2885.1;
- The protection measures, both physical and procedural, required against third-party damage in accordance with AS 2885.1;
- The physical characteristics of the pipeline, including the diameter, wall thickness, Specified Minimum Yield Strength (SMYS), fracture toughness properties, strengths test pressure and leak test pressure;
- The physical condition of the pipeline, as determined from records of the operation and maintenance and from reports of examinations, inspections and monitoring including those pertinent to corrosion mitigation; and,
- The pipeline design pressure.

Following an update to design condition changes, the PIMP will be updated where it is determined that revision and or adjustment is required.

9.2 Safety Management Study (SMS)

The Safety Management Study for each transmission pipeline is reviewed for any changes or developments which may impact on the pipeline. The studies are reviewed at a maximum interval of 5 years or as required in the course of operation should circumstances change, and provide the rationale for pipeline upgrading and the ongoing or routine maintenance and operations activities.

Where the risks have changed, a review of that section of the SMS may be completed rather than a full review. The pipeline SMS is updated to reflect these on-going changes and also considers the latest requirements of AS 2885 at those opportunities. In addition to implementing design controls for external threats identified in the original SMS, the effectiveness of the threat mitigation controls themselves are monitored and discussed at the SMS review.

The Safety Management Study is a multi-faceted process, which is carried out by a multi-disciplinary team with an intimate knowledge of the different pipeline aspects.

The risk evaluation is conducted for raw risks and for the residual threats based on the Risk Matrix of AS2885.1.

Following an SMS the PIMP may need to be updated where additional actions are required to achieve ALARP status.

The SMS shall be conducted in accordance with APA's "Safety Management Study and Location Class Review Policy – Gas and Liquid Pipelines".

APA QLD transmission pipeline SMS records are contained in an SMS Database for each asset.

9.2.1 Pipeline Location Class Review

Pipeline location classes are assigned in accordance with AS 2885.1. The location class is reviewed as part of the Safety Management Study review and complies with the requirements of AS 2885 part 1 and 3.

Location class reviews are conducted on a 5-yearly interval and immediately after the following threats were identified:

- External threat and encroachment;
- New development or subdivision approval request;
- New infrastructure encroachment;
- Identification of new or modified land use.

9.2.2 QLD Assets SMS Summary

A summary of the SMSs for each asset is in

Table 7. The items contained in this table summarise the specific actions that impact the PIMP which are required to maintain ALARP for intermediate risks and above. These activities are above the normal practices described in the PMS and the routine maintenance section of this document and may involve special location specific requirements. Low or Negligible risks are not included in this section.

The table may contain wording that requires reading in conjunction with the actual SMS study report. A full copy of the SMS Review reports can be found in the following references:

- Q-01-Q1-RAE-G-004 "South West Queensland Pipeline – AS 2885 Safety Management Study Report" (2011 – SWQP only)
- Q-01-Q1-RAE-G-006 "2011 SWQP Risk Assessment Threats and Failure Assessment" (2011 – follow up to G-004 above)
- Q-01-100-RAE-G-001 "QSN3 Project – Safety Management Study" (2011 – SWQE and QSNE – only SWQE still valid, QSNE superseded by Q-02-102-RAE-G-004 below)
- Q-02-102-RAE-G-004 "QSN Link and QSNE – Safety Management Study 5-year Review" (2013)
- RB-RP-P-002_RBP_SMS "Pipeline Safety Management Study, Roma – Brisbane Pipeline (2011)"
- RBP Metro SMS Review 2014
- CGP-SMS-2011 "Carpentaria Gas Pipeline – SMS Report"
- BWP 2013 SMS Review
- Peat Lateral 2011 SMS Review
- Kogan North 2012 SMS Review

Note that there have been no actions requiring adjustment of the maintenance plan frequency or schedule.

Table 7 - Risk Assessment Result of 'Intermediate' Risk Impacting the PIMP

Pipeline	Location	Threat / Comment	Consequence	Likelihood	PIMP Related actions to achieve ALARP
SWQP and SWQE	Non Locational	Boring vertical/Possible pipeline interference from boring or exploratory drilling activities. Water boring is also considered credible.	Major	Remote	Threat considered being ALARP due to procedural measures, and heavy wall (*heavy reliance on external interference management)*
	Non Locational	Excavation of Dams/Landowner could construct dams, borrow pits etc. (note applies to any earth moving activity involving the use of bulldozers and similar equipment	Major	Remote	Procedural controls, control, particularly landowner liaison is robust. Mail outs are targeted to this type of activity. Threat is considered to be ALARP

	Non Locational	Boring horizontal/ HDD activities could occur along the pipeline route	Major	Remote	With the controls in place, and the low likelihood of the HDD occurring along the SWQP, this threat is considered to be ALARP
	Non Locational	Communication cable installation/optic fibre installation to unknown depths	Major	Remote	Threat considered being ALARP particularly due to most cables buried at shallower depth than pipeline and where cables are buried at approx. 1200mm, this occurs at roads where pipe is heavier wall and at greater depths
	Various Stations	Vehicle impact causing damage to valves and pipework	Major	Remote	Threat considered to be ALARP due to procedural controls and change to permanent pig traps
	HI area at Ballera. (KP 0.57)	Boring Vertical - Possible pipeline interference from boring or exploratory drilling activities.	Major	Remote	Threat considered to be ALARP due to procedural measures, and heavy wall in vicinity of Ballera (*heavy reliance on external interference management for ALARP)*
	Sectional – Bul 02 – Pastoral lease – Nappa Merrie (KP 1.760)	Damage to piping during excavation -Epic excavation of SWQP using excavator with general purpose bucket, or light equipment	Major	Remote	Procedural measures considered being robust in controlling this threat, plus wall thickness expected to provide some protection. Threat is considered to be ALARP with action raised to reinforce DOC with landowner
	Sectional – Bul 02 – Pastoral lease – Nappa Merrie (KP 1.760)	Maintenance activities by third parties over the pipeline - Landowner excavates to 300mm in depth and has a grader	Major	Remote	Procedural measures considered being robust in controlling this threat, plus pipeline separation by burial will be 900mm minimum. Threat is considered to be ALARP with action raised to reinforce DOC with landowner
	Pastoral Lease (Bundella) (KP 751.054)	Boring Vertical/Possible pipeline interference from boring or exploratory drilling activities.	Major	Remote	Liaison with relevant parties can be expected to identify boring activities ahead of time, and procedures are robust *(heavy reliance on external interference management for ALARP)*
	SWQP/ SWQE - Non Locational	Construction of other oil/gas pipelines/Excavation activities from 3rd Party	Major	Unlikely	Unlikely frequency as area not considered to have high construction activity (*reliance on external interference management for ALARP)*

QSN Link and QSNE	Non Locational	Boring horizontal/ HDD activities could occur along the pipeline route	Major	Remote	With the controls in place, and the low likelihood of the HDD occurring along the QSN, this threat is considered to be ALARP
	Sectional – QSN-02-NAPPA MERRIE-415CP8355115 (KP 0.01)	A maintenance activity by third parties over the pipeline/Santos contractors has maintenance and excavation equipment ranging from 12.5T to 36T which may impact the pipeline or the above ground facilities.	Major	Remote	Procedural measures considered being robust in controlling this threat, plus wall thickness expected to provide some protection. Threat is considered to be ALARP with action raised to reinforce DOC with landowner.
Carpentaria Gas Pipeline	Threat ID:1275 Buried utility – gas pipeline crossing and parallel	External interference/ Maintenance of buried utility adjacent or crossing the pipeline	Major	Remote	Review emergency response protocols for this pipeline and repair equipment/strategies for such incident
	Threat ID: 1335 General rural location (excluding water ways) – grazing land	External interference/Core sampling by mining exploration companies	Major	Remote	Upon discussion with lease/permit owners, determine optimum location for additional signage in areas where sampling activity likely. Consider a sign that is unique to this application (rather than just the standard)
Peat/Scotia lateral Pipeline	Threat ID: 1455 General installation – Rural	External interference/Buried service installation, major (CSM pipelines etc., incl. excavators and chain trenchers)	Major	Low	Increase gas awareness programs with new resources/infrastructure companies and ensure they are on the register. *heavy reliance on external interference management)*
	Threat ID: 1505 General installation – All Control fails	External interference/ Buried service maintenance, excavation – all control fails	Major	Remote	Consider installing a concrete slab at every pipeline crossing on the Peat Lateral pipeline. This action was not adopted due to it costing a greater amount tan the maximum justifiable spend; therefore the intermediate risk was deemed to be 'As Low As Reasonably Practical' (ALARP) (*heavy reliance on external interference management)*

RBP	Non-location-specific	Axial SCC leading to leak or rupture of 1969 pipeline	Catastrophic (worst case – rupture in populated area)	Hypothetical	Finalise and implement SCC Management Plan. Review wall thickness and location class data to identify any light-wall DN250 pipe in populated areas.
	Non-location-specific	Circumferential SCC due to strain on pipe leading to leak or rupture	Catastrophic (worst case – rupture in populated area)	Hypothetical	Finalise and implement SCC management plan as above. Complete digup and MPI of remaining strain events Complete XYZ pigging and strain analysis of remaining 2x DN250 sections
	Non-location-specific	Dent combined with metal loss or located on weld could leak or rupture	Major	Remote	Implement risk based excavation and repair program Complete MFL and caliper pigging of remaining DN250 sections
	Various facilities	Vehicle impact on aboveground facilities (errant truck from nearby road)	Major	Remote	Vehicle impact risk study complete; barriers installed at most at-risk sites; project in progress for remaining identified sites.
	Section 35 (Karalee shopping Centre) Karalee shopping centre (KP 386.3)	All control fail – pipe rupture by heavy machinery involved in developing adjacent land	Catastrophic	Hypothetical	No effective mitigation measures available for less than maximum justifiable spend (max justified spend to eliminate risk = $10,000) (*heavy reliance on external interference management)*
	Section 55 (Wishart – Belmont), Wecker Road (KP 427.4)	All control fail – pipe penetrated by backhoe or small excavator involved in water main repair	Severe	Unlikely	Pipeline awareness – consider increased effort, possibly jointly with DBYD, possibly including media advertising, if possible targeting high-threat groups (*heavy reliance on external interference management)*
	Section 65 (Camira – Ellengrove), Future railway crossing, Centenary Hwy (KP 8.6)	All controls fail - pipe penetrated by auger sinking piles for railway bridge	Catastrophic	Hypothetical	No effective mitigation measures available for less than maximum justifiable spend (*heavy reliance on external interference management)* Note – this railway crossing is now complete with no incidents.

	Section 18 – Toowoomba Range railway crossing	Ongoing slope instability (short term)	Severe	Unlikely	Slope drainage / management plan to be considered to reduce water infiltration. Now rolled into ongoing Circumferential SCC management plan
	Brisbane Metro – urban area 1969 pipelines	3rd party buried service maintenance or construction – 20T excavator could penetrate leading to leak	Major	Remote	3rd Party agreements; DBYD improvements; incident follow up improvements; review slabbing locations; patrol frequencies
	Brisbane Metro – urban area 1969 pipelines	Vertical boring (power pole, road sign, etc) could penetrate and leak	Major	Remote	As above
BWP	In the 2013 BWP SMS Review, all threats were Low or Negligible. Nothing was Intermediate or above.				

9.3 Remaining Life Review (RLR)

The pipeline RLR is a critical document for pipeline safety and shall be developed within a 10 year interval or immediately following failure of the pipeline in accordance with APA's policy the "Remaining Life Review Policy".

The outcome of the reviews for each asset shall determine any actions and or recommendations to ensure the pipeline and their facilities are fit for continued service, practices, and that processes are in place to enable pipeline and facility operation at least to the end of its design life.

As a minimum a remaining life review shall include detailed engineering assessment of the following areas:

- Demonstration of structural integrity in accordance with AS 2885.3 to confirm the QLD Assets can continue to contain fluids at the design conditions.
- The type and configuration of any defects, the rate of corrosion and the minimum remaining wall thickness
- Fracture control plan in accordance with AS 2885.1 and the identification of any changes required to the fracture control methods (currently in development).
- Review of the Safety Management Study conducted in accordance with AS 2885.1 and the identification of any changes required to the mitigation methods.
- Review of the adequacy of the asset's PIMP, operating and maintenance, ERP, and safety and environmental procedures.

9.4 Fracture Control Plan

APA is currently reviewing and developing fracture control plans for each of its pipelines to meet the requirement of AS 2885.1. Fracture control plans define the measures required to limit fracture propagation in the event that a pipeline rupture occurs. The fracture failure modes of pipelines depend on the material of construction, which must resist brittle fracture and tearing fracture under all possible operating conditions of the pipeline. Measure may include the implementation of physical and procedural control.

The fracture control plans for pipelines shall satisfy the following criteria outlined in section 4.8 of AS 2885.1, incorporating the requirements for retrospective application

- Brittle fracture will not occur under any approved pipeline operating scenario. The steel ductility at the design minimum temperature will be used to satisfy this objective.
- 'Standard' wall pipe will be designed to arrest fast tearing fracture within two pipes in either direction from the initiating pipe. All other pipes will arrest fast tearing fracture from the initiating pipe.
- Steel toughness, strength and thickness at the maximum pressure and the most severe temperature and gas composition conditions are used to satisfy fracture control.
- Calculations of the critical defect length, radiation contour radius and resistance to penetration data for use in the pipeline Safety Management Study.

9.5 Fatigue

Fatigue due to pressure cycling, temperature cycling and other cyclic loadings of pipe work including buried pipeline and station piping shall be reviewed to identify pipeline structural integrity issues typically carried out during pipeline RLR. Engineering assessment of pipeline fatigue shall utilise historical pressure and temperature cycle data for analysis and fatigue calculation shall be conducted in accordance with the methodology outline in Appendix N of AS 2885.1.

In some situations fatigue may become an issue in above-ground station piping and where fatigue has been identified, AS 4041 and ASME B31.3 shall be used.

10 ASSET INTEGRITY PROGRAMS

The tables in this section document the activities undertaken by APA Group to monitor and manage integrity of QLD pipelines.

Table 8 - Asset Integrity Programs

Activity	Frequency	Driver	Compliant	Comment
Direct Assessment & Excavation Programs				
SCCDA - Cracking	As required	Integrity	Yes	Refer SCC Management Plan
Pigged pipeline	As required	Integrity	Yes	Further details of all ILI frequencies can be found in Table 9
ILI Validation/Urgent Repair	With ILI	Integrity	Yes	
Coating Defect Repair	With DCVG	Validate of DCVG inspection anomalies	Yes	Coating defect repair are carried out post DCVG survey. This is an ongoing program both for un-piggable pipelines.
Non Destructive Testing (MPI) Inspection when pipe is exposed	As required	Integrity	Yes	As a requirement of non-destructive testing; Magnetic Particle Inspection (MPI) shall be conducted when the buried pipeline is exposed (excavated) for all pipelines where damaged, disbanded or porous coating is detected.
Buried Station Pipework	5 yearly	Integrity/ DCVG survey	Yes	This is an ongoing program of coating defect survey of buried pipe work

Table 9 – Pipeline Inline Inspection Program (Magnetic Flux Leakage ILI)

Licence	Pipeline Name	Section	Frequency	ILI Action	Last Run	Next Run
2	Roma Brisbane Pipeline (RBP) DN 400	Wallumbilla-Yuleba	7 years	MFL + Geometry + Mapping XYZ	2011 GE-PII (MFL + Geom +Mapping)	2018 (MFL + Geom + Mapping) (Note - 16_F Oakey_Gatton at FY15 as part of Toowoomba Range slope stability plan)
		Yuleba-Condamine				
		Condamine-Kogan				
		Kogan–Dalby				
		Dalby–Oakey				
		Oakey–Gatton				
		Gatton-Swanbank via Redbank				
	Roma Brisbane Pipeline (RBP) DN 250	10_A Wallumbilla-Yuleba	5 years	MFL + Geometry + Mapping XYZ	2014 MFL + Geom + Mapping ** 10_B and 10_G (not run yet) to be completed Q1/Q2 2015	2019 MFL + Geom + Mapping
		10_B Yuleba-Condamine				
		10_C Condamine-Kogan				
		10_D Kogan–Dalby				
		10_E Dalby-Oakey				
		10_F Oakey–Gatton 1				
		10_G Gatton-Bellbird Park				
	Roma Brisbane Pipeline (RBP) Metro Pipelines	DN400 Collinwood Park take off–Ellengrove commissioned as RBP Loop6 - 2002	7 years	MFL + Geometry + Mapping XYZ	March 2010 Rosen MFL + Mapping	2017 MFL + Geom + Maping
		DN300 "metro" from Bellbird Park to SEA block valve via Ellengrove and	5 years	MFL + Geometry + Mapping XYZ	April 2011 GE-PII MFL + Geom + Mapping	2016 MFL + Geom +

[1] Note – Completion of Toowoomba Range railway crossing replacement is required prior to next pig run in this section

Licence	Pipeline Name	Section	Frequency	ILI Action	Last Run	Next Run
		Mount Gravatt - built 1970				Mapping
		DN200 Lytton Lateral from SEA block valve to Caltex Refinery - commissioned 2010	7 years	MFL + Geometry + Mapping XYZ	n/a commissioned 2010	2017 MFL + Geom + Mapping
		DN200 "metro" from SEA block valve to Gibson Island - built 1970	7 years	MFL + Geometry + Mapping XYZ	2011 GE-PII MFL + Geom + Mapping	2018 MFL + Geom+Mapping
		DN400 Metro Looping Number 1 - commissioned 2012	7 years	MFL + Geometry + Mapping XYZ	n/a commisioned 2012	2019 MFL + Geom + Mapping
18 (SA)/12 9 (Qld)	QSN Link	18" QSNE Queensland-South Australia-New South Wales Expansion - Ballera to Moomba - commissioned 2012	10 years	MFL + Geometry + Mapping XYZ	n/a Commissioned 2012	2022 MFL + Geom + Mapping
		16" QSN link Queensland-South Australia-New South Wales - Ballera to Moomba - commissioned 2008	10 years	MFL + Geometry + Mapping XYZ	n/a commissioned 2008	2018 MFL + Geom+Mapping
24	18" SWQP South West Queensland Expansion Pipeline (8 sections) Ballera to Wallumbilla	Wallumbilla via Scraper Station SS7 to Scraper Station SS6	7 Years	MFL + Geometry + Mapping XYZ	n/a commissioned 2012	2019 MFL + Geom + Mapping (will be 4 sections to run)
		Scraper Station SS6 via Scraper Station SS5 to Scraper Station SS6				
		Scraper Station SS4 via Scraper Station SS3 to Scraper Station 2				

Licence	Pipeline Name	Section	Frequency	ILI Action	Last Run	Next Run
		Scraper Station SS2 via Scraper Station SS1 to Ballera Station				
	16" SWQP South West Queensland Pipeline (8 sections - Ballera to Wallumbilla	Wallumbilla via Scraper Station SS 7 to Scraper Station SS6 Scraper Station SS6 via Scraper Station SS5 to Scraper Station SS6 Scraper Station SS4 via Scaper Station SS3 to Scraper Station 2 Scraper Station SS2 via Scaper Station SS1 to Ballera Station	10 Years	MFL + Geometry + Mapping XYZ	2010 Roesn MFL	2020 MFL+Geom+Mapping (will be 4 sections to run)
41	CGP Carpentaria Gas Pipeline DN350 Ballera to Mount Isa (Mica Creek) (6 segments)	Ballera to Mt Howitt Mt Howitt to Morney Tank Morney Tank to Davenport Downs Davenport Downs to Springvale Springvale to Noranside Noranside to Mica Creek	10 years	MFL + Geometry + Mapping XYZ	2013/2014 MFL+Geometry+Mapping	2024 MFL+Geometry+Mapping
42	Cannington Lateral Pipeline (CLP)	Corrie Downs off-take to Cannington Mine	10 years	MFL + Geometry + Mapping XYZ	Dec 2012 GE-PII MFL + Geom + Mapping	2022 MFL + Geom + Mapping
50	Mica Creek Meter Station (MCMS)	173m – DN 150 70m – DN 300	unpiggable	unpiggable	unpiggable	unpiggable
51	Mount Isa Mines	615m – DN 150	unpiggable	unpiggable	unpiggable	unpiggable Note: Could be made

Licence	Pipeline Name	Section	Frequency	ILI Action	Last Run	Next Run
		89m – DN 80 5.7 km MCMS to Pendine Street				piggable with addition of launcher/receiver. This should be considered in the future given it is located in a populated area?
74	Peat Lateral	Scotia to RBP	7 years	MFL + Geometry + Mapping XYZ	April 2010 Rosen MFL+ Mapping	2017 MFL + Geom + Mapping
120	Kogan North Central Gas Processing Facility		unpiggable	unpiggable	unpiggable	unpiggable
123	Berwyndale Wallumbilla Pipeline	112km – DN 400	10 years	MFL + Geometry + Mapping XYZ	n/a commissioned 2010	2020 MFL + Geom + Mapping

Note that the QLD regulations pose additional requirements for pipelines that are classified as “Strategic” in accordance with the Petroleum and Natural Gas Act. These requirements have been taken into account in this table.

11 ROUTINE MAINTENANCE ACTIVITIES

Error! Not a valid bookmark self-reference.10 below lists all routine maintenance activities currently undertaken by APA Group in relation to maintaining pipeline integrity for QLD assets.

Table 10 – Routine Maintenance Activities

Activity	Frequency	Driver	Comments (Supporting documentation/reference, asset specific)
Pipeline Corrosion Control Activities			
CP survey & audit	1 yearly for rural and 6 monthly for metropolitan area	Integrity	Work code: B70
CP test point patrol	1 Monthly	Integrity	Work code: B71
CP test point T/R circuits checks	1 monthly or remote monitored	Integrity	Work code: B73
Watering in of buried anode ground bed	6 monthly (nominal)	Integrity	Work code: B80
Surge Diverter / Insulation Joint Check	With CP Survey	Integrity	WMS: QLD-GT-WI-B70-CP survey
Station Pipework CP Survey	With CP Survey	Integrity	WMS: QLD-GT-WI-B71-CP survey
Interference testing	As required	Integrity	Testing for CP interference shall be carried out in agreement between APA and third party as required by Queensland regulations
Cased crossing isolation check	Non-routine	Integrity	Where required in conjunction with CP checks.
CP Current demand monitoring	Continuous SCADA monitoring	Integrity	Where applicable
CP Multimeter check and calibration	1 yearly (field) 3 yearly (master)	Integrity	Calibration of the Digital Multimeters used for testing CP. Work Code: A10
CP Internal/External corrosion probes monitoring	3 monthly (6 monthly ultrasonic probes)	Integrity	Work code: H29
Painting above ground pipe work and structures	5 yearly or as required (condition based)	Integrity	Work code: S44
Coating defect refurbishment/ assessment	Pending ILI and or DCVG result	Integrity	Work code: Nil
DCVG	As required (Non-routine) or 5 yearly unpiggable sections	Integrity	Work code: B75; identified unpiggable sections i.e. offtakes etc. are in WMS with 5 yearly DCVG
Pipeline Land Management Activities			
Pipeline awareness liaison	1 yearly	Lands Management	Document 320-PL-HEL-0001
Ground patrol	Frequency varies depending on pipeline	Lands Management	Ground patrol frequency, refer to document 320-PR-HEL-0002, Appendix 4
Gas Leak survey	1 yearly, (5 yearly) RBP, CGP, Peat and Kogan	Lands Management	Work code: B69, for above ground

Activity	Frequency	Driver	Comments (Supporting documentation/reference, asset specific)
	North.		
Aerial patrol	Frequency varies depending on pipeline	Lands Management	Aerial patrol frequency, refer to document 320-PR-HEL-0002, Appendix 4.
Aerial photography	As necessary	Features found by aerial patrol	Document 320-PL-HEL-0001
DBYD follow up	As required	Lands Management	Document 320-PL-HEL-0001
Pipeline land awareness program	1 yearly & as necessary	Lands Management	Document 320-PL-HEL-0001, Appendix 1.
Monitoring development proposals	1 yearly / As required	Lands Management	Document 320-PL-HEL-0001, SMS
Depth of cover checks	As required	Lands Management	Document 320-PL-HEL-0001
Vegetation control	As required	Lands Management	Document 320-PL-HEL-0001, and determined by Aerial and Ground patrol.
Ground movement/erosion monitoring	Aerial and Ground patrolling	Lands Management	Document 320-PL-HEL-0001, and determined by Aerial and Ground patrol.
Pressure control System			
Minor inspection	Weekly	Reliability	Work code: C01
Minor inspection	Monthly	Reliability	Work code: C02
Major maintenance	1 yearly	Integrity/reliability	Work code: C1A
Valve maintenance			
General inspection	3 monthly (Hold)	Integrity	Work code: S30
Valve service minor	6 monthly	Reliability & Integrity	Work code: C01
Major service	2 yearly alternating with N03 (Hold)	Integrity	Work code: N02
Full overhaul	2 yearly alternating with N02 (Hold)	Integrity	Work code: N03
Station Maintenance			
Inspection of valve, scraper and metering sites	3 monthly	Reliability, Safety	Work code: S30, as per AS 3788
Inspection of above ground pipework and fittings	3 monthly	Reliability, Safety	Work code: S30, as per AS 3788
Scraper Minor service	2 yearly	Integrity	Work code: N10

Activity	Frequency	Driver	Comments (Supporting documentation/reference, asset specific)
Scraper Major service	2 yearly	Integrity	Work code: N11
Metering Station control system check	Weekly or 2 weekly	Reliability, Integrity	Work code: N20
Meter/Regulator station instrument & Electrical check	1 yearly	Reliability	Work code: N21
ESD Functionality Test	1 yearly	Reliability	Kogan North Compressor Station
Auxiliary battery power supply service	3 monthly (Compressor/CP), 6 monthly (Meter Station)	Integrity and Reliability	Work code: S14
Filter inspection	6 monthly (Filters) or 5 yearly (Strainers); 1 year filter at KN	Integrity & reliability	Work code: S16
Pressure vessel inspection external	2 yearly	Reliability & Integrity	Work code: S20, as per AS 3788
Pressure vessel inspection internal	4 yearly	Reliability & Integrity	Work code: S19, as per AS 3788
Inspect Orifice Plate	1 monthly (dependent on site as per GTA or validation)	Quality & Reliability	Work code: S47
Turbine meter maintenance and replacement	2 yearly	Quality	Work code: S48
Planned meter change	3 yearly	Quality & Reliability	Work code: S51
Gas Chromatograph inspection & calibration	Monthly inspection / 2 yearly service; KN validation 3 months	Quality	Work code: S53
Routine gas quality checks	6 monthly	Quality	Work code: S54
RTU/FC backup battery change	3 yearly	Integrity	Work code: S60
Meter tube metrology audit	3 yearly (RBP), 2 yearly (CGP)	Integrity	Work code: S61
Meter station validation	1 monthly to 6 months (depending on GTA and meter type)	Quality and Reliability	Work code: S62
Moisture analyser calibration	As required by Work code: S86	Quality and Reliability	Work code: S85
Relief Valve (RV) inspection	All 6 monthly except 4 yearly for Yuleba and Condamine MLVs	Reliability & Integrity	Work code: S86

Activity	Frequency	Driver	Comments (Supporting documentation/reference, asset specific)
Station maintenance of compressor station structures	1 yearly	Reliability & Safety	Work code: C01
Compressor mechanical & electrical service – rotating	4,000hr (mechanical) & 6 monthly (electrical)	Reliability	Work code: C20
Compressor service - reciprocating	6 weekly 1000hr, 4000hr, 8000hr service	Reliability	Kogan North station, WCS 1 and WCS 2
Inspection of compressor station	1 Weekly	Reliability	Work code: C03
Compressor station electrical inspection	1 yearly	Reliability & integrity	Work code: C04
Compressor vibration survey	Monthly or at service (only checked when running) [For s20s 1000hrs or yearly] Kogan North Fixed system	Reliability & integrity	Work code: C07
Compressor test run	1 monthly if required	Reliability	Work code: C29
Fin Fan After-cooler cleaning	1 yearly	Reliability & integrity	Work code: C08
Check operation and calibration telemetry unit	6 monthly	Reliability & safety	Work code: C09
Inspect fire protection system and equipment	6 monthly	Safety	Work code: A07
Uninterruptible Power Supply Service	1 yearly	Reliability	Kogan North Compressor Station
Gas/Electrical Alternators (GEA)			
Check operation and calibrate compressor equipment	1 monthly	Reliability & safety	Work code: C03
Check operation and calibrate electrical equipment	6 monthly	Reliability & safety	Work code: C04
Check operation and calibrate compressor equipment	1 yearly	Reliability & safety	Work code: C09
Ipswich / Swanbank area specific			
Above ground monument surveying	Annually and following ant significant events	Integrity	
Swanbank lateral culvert inspection (pipe is only partially buried and is inspected for straightness etc. via manholes)	Annually and following ant significant events	Integrity	

Activity	Frequency	Driver	Comments (Supporting documentation/reference, asset specific)
Swanbank underground coal fire temperature monitoring	Monthly	Integrity	

12 TERMS & ABBREVIATIONS

The specific terms and abbreviations used in this document are listed below:

Abbreviations

Abbreviation	Definition
AS	Australian Standard
CMMS	Computerised Maintenance Management System
CP	Cathodic Protection
CTE Coating	Coal Tar Enamel Coating
CUI	Corrosion Under Insulation
DBYD	Dial Before You Dig
DCVG	Direct Current Voltage Gradient
DEA	Diesel Electric Alternator
D.L. FBE Coating	Dual Layer Fusion Bonded Epoxy Coating
ECDA	External Corrosion Direction Assessment
EMAT	Electro Magnetic Acoustic Transducer Testing
FBE Coating	Fusion Bonded Epoxy Coating
FFP	Fitness For Purpose
GEA	Gas Electric Alternator
GSM	Global System for Mobile
GTA	Gas Transportation Agreement
ICCP	Impressed Current Cathodic Protection
ILI	In-Line Inspection
IP	Internet Protocol
IRE	Internal Resistance Error
LMP	Land Management Plan
MAOP	Maximum Allowable Operating Pressure
MFL ILI	Magnetic Flux Leakage In-Line Inspection
MOP	Maximum Operating Pressure

Abbreviation	Definition
MPI	Magnetic Particle Inspection
NDE	Non Destructive Examination
PIMP	Pipeline Integrity Management Plan
PMS	Pipeline Management System
PE Coating	Poly Ethylene Coating
PLC	Programmable Logic Controller
POD	Probability of Detection
PRS	Pressure Regulating Station
PSTN	Public Switched Telephone Network
RLR	Remaining Life Review
RTU	Remote Terminal Unit
SCC	Stress Corrosion Cracking
SCADA	Supervisory Control and Data Acquisitions
SCCDA	Stress Corrosion Cracking Direct Assessment
SMS	Safety Management Study
UT	Ultrasonic Testing
UHBE	Ultra High Build Epoxy

13 REFERENCES

Reference	Description / Document Description
APA Standards	
320-MX-AM-0001	AS 2885.3 Approval Matrix
320-PL-HEL-0001	Land Management Plan
530-GD-E-0001	Corrosion Management Guideline
Q-01-100-RAE-G-001	QSN3 Project – AS 2885 Safety Management Study Report
Q-01-Q1-RAE-G-004	South West Queensland Pipeline – AS 2885 Safety Management Study Report
Q-01-100-RAE-G-002	QSN Link – Safety Management Study
Q-01-Q1-RAE-G-006	2011 SWQP Risk Assessment Threats and Failure Assessment
RB-RP-P-002_RBP_SMS	Pipeline Safety Management Study, Roma – Brisbane Pipeline (2011)
CGP-SMS-2011	Carpentaria Gas Pipeline – SMS Report
POL-1-33 SAOP	Safety and Operating Plan – Queensland Transmission Facilities
SP-M-9602	Coating Above Ground Pipework, Valves and Fittings
SP-M-9601	Coating of Buried Pipework, Valves and Fittings
TBA	APA Remaining Life Review Policy
TBA	Assessment of metal loss results from MFL In-Line Inspection - Draft
TBA	MAOP/MOP review policy-Gas and Liquid Pipelines
TBA	RBP Pipeline system – SCC Integrity management plan
SR-126	Record Management Procedure
TBA	Safety Management Study and Location Class review policy – Gas and Liquid Pipelines
TP-APAA-104-EG-0043	Technical Guideline for in-service inspection of pressure equipment
Australian Standards	
AS 2885.3, 2012	Gas and liquid petroleum Part3 - Operation and maintenance
AS 285.1	Gas and liquid petroleum Part1 – Design and construction
AS 3788	Pressure equipment: In-service inspection
AS 2832.1	Cathodic protection of metals, Part 1 - Pipe and cables

Reference	Description / Document Description
AS 4041	Pressure Piping
International Standards	
IEC 61511	Safety Lifecycle Manual
ASME B31.3	Process Piping

PLAN

ASSET MANAGEMENT

5 Year Maintenance & Upgrade Plan – RBP CP System

Document No		320-PL-AM-0060			
Rev	Date	Status	Originated/ Custodian	Checked	Approved
1.0	25/08/2016	Issued for Use	N. Doblo Corrosion Engineer	F. Carroll Engineering Services Manager	C. Bonar Manager East Coast Grid Eng
			[Name] [Position]	[Name] [Position]	[Name] [Position]

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Table of Contents

1. Executive Summary

This document details the 5 year CP outlook for the Roma to Brisbane Pipeline System. The RBP was commissioned in 1969 and has a number of key factors to which make its CP system unlike most other pipelines. These factors include

- Ageing Over-the-ditch single layer tape wrap on the DN250 Line
- Parallel DN400 loop line electrically connected to the DN250 line of a varying age
- A large number of uncommonly high output CP units (for a pipeline)
- Large sections of black soil along pipeline route
- Electrical bonding between sections and pipelines that has evolved on a as needs / as fundable basis.
- The CP system of the pipeline has accrued a significant maintenance debt due to various reasons.
- Sixty percent of the CP units are running above 80% of capacity and are quite old and minimally protected from surges.

To develop a maintenance plan, and associated budget, the design life of a typical RBP CP system, along with historical trending has been reviewed with the following conclusions

- 15 Years was determined to be an appropriate design life for an RBP CP system.
- $400,000 Required for Rolling replacement of the 69 CP systems every 15 years
- The RBP CP system has increased by an average of 1.4 installations per year.
- 1/year is more likely given the reliance on sacrificial anodes post construction.
- $140,000 estimated being required for each completely new site required.
- $600,000 rolling annual budget likely to be required to maintain CP system.

The budgets proposed and identified upgrades are identified in the table below

Table 1: Budget Forecast Summary

Fiscal Year	# Anode beds	# CP units upgraded		Labour	Equipment	Contractor	**Total**
FY15/16 Actual	2	10 Purchased		$59,000	$308,000	$133,000	**$500,000.00**
FY16/17	3	17		$70,000	$320,000	$239,000	**$629,000.00**
FY 17/18	6	4		$72,000	$393,000	$177,000	**$642,000.00**
FY 18/19	5	5		$61,000	$375,000	$212,000	**$648,000.00**
FY 19/20	5	5		$61,000	$375,000	$212,000	**$648,000.00**
FY 22/21	5	5		$61,000	$375,000	$212,000	**$648,000.00**
FY 21/22	5	5		$61,000	$375,000	$212,000	**$648,000.00**

2. Introduction

This document details the 5 year CP outlook for the Roma to Brisbane Pipeline System. The RBP was commissioned in 1969 and has a number of key factors to which make its CP system unlike most other pipelines. These factors include

- Ageing Over-the-ditch single layer tape wrap on the DN250 Line
- Parallel DN400 loop line electrically connected to the DN250 line of a varying age
- A large number of uncommonly high output CP units (for a pipeline)
- Large sections of black soil along pipeline route
- Electrical bonding between sections and pipelines that has evolved on a as needs / as fundable basis.
- The CP system of the pipeline has accrued a significant maintenance debt due to various reasons.
- Sixty percent of the CP units are running above 80% of capacity, are quite old and minimally protected from surges.

These factors have produced the following challenges to the pipeline CP system

1. High Current Demand (24mA/m2 is the last calculated value for the first 6 miles). Anecdotal evidence suggests the Moonie to Brisbane (a similar but older pipeline) line reached 36mA/m2 before plateauing. 20mA/m2 is the textbook value for bare steel in soil with even current distribution.
2. The DN400 Loop line appears to be allowing protection of the DN250 from larger, more widely spaced CP units than traditionally expected by acting as a header cable to distribute CP current without excessive voltage attenuation. The unstructured method of bonding between the two lines however often results in either adverse interference on the DN400 or potentials more negative then -1.200mV to CSE.
3. The existing bonding, along with the large number of CP units and the DN400 "header cable" presents significant challenges in determining an appropriate CP survey procedure to ensure all IR errors are accounted for. These include, remote but still influencing CP units along with backflow of current between the two pipelines via the cross bonds.
4. The ability to accept large amount of injected current per installation without over protection due to the DN400 loop line has resulted in larger than normal CP units and anode beds (80 Amp rated). These CP units cannot be pole mounted, requiring installation of concrete slabs for support and frames to reduce the likelihood of flood damage.
5. Historical placement of anode beds has often been too close to the pipeline when current demand has increased causing interference from the anode bed on the pipeline.
6. Replacement of these beds should involve a detailed engineering design including soil resistivity testing and additional easement acquisition. However, at times, where urgent replacement is required, a like for like replacement has been done.

7. Many of the existing CP units are running at a very high percentage of the design output, are of a very basic design (constant voltage) and often quite old. This results in the units being extremely susceptible to burn out, lightning strike and incorrect output due to soil resistivity changes.

   Average failure rate reached the order of one unit per month in FY14/15 after a significant increase in current demand. Units require fortnightly operational checks and output adjustment required compared to the Moomba Sydney schedule of one check every two months.

   There is historical evidence to show a movement away from this basic CP unit design in the mid-80s to an automatically controlled unit with better surge protection and self-limiting controllers to reduce burn out. A range of unit types are still in operation on the RBP at this time.

8. CP units have historically been checked by mechanical technicians and been a Run to Failure item. Spares were kept of each CP unit size and complete units swapped when a failure occurred and sent away for repair. Increasing demand has required accelerated replacement of operational spares including purchase of larger units.

9. Due to the large current demands, high utilization of existing systems and voltage attenuation a functional failure of one unit cannot be "covered" be increasing the load on the surrounding units. In some case, one unit failing can cause a domino effect of further failures in nearby units. The result is the section covered by the faulty unit can become completely unprotected, while the sections either side are dragged down to marginal or partial protection levels.

   The easiest way to reduce the failure rate of the units due to high demand is to increase the reliability of the units. This could be achieved such as using newer style of units with integral governors to prevent operation outside the design limits or using a higher capacity unit. APA is taking the approach in the ongoing CP management and upgrade program.

3. Design Life and End of Life replacement

Impressed Current Cathodic Protection systems are generally considered long life installations with typical lifespans for both CP units and anode beds to be in the range of 20 years if still operating within their design capacity.

Given the increasing current demands and high capacity utilisation, a 15 year design life for both anode beds and CP unit would be more appropriate for the RBP and in line with historic experience on the RBP

Given that there are currently 69 CP systems on the RBP, this will result in 4.6 systems reaching "end of life" per year. It could be assumed, with the RBP, that a capacity upgrade will be required at this end of life point. The RBP has also averaged an increase of 1.4 additional / infill CP units per year.

Based on these life estimates, budgets have been based on the largest capacity system currently being installed (80Amp / 50 Volt CP unit, with suitable sized anode bed). With estimates for a new Anode bed and CP units at an existing location currently about $100,000.00 and completely new locations estimated at $140,000.00 an annual budget of at least $600,000.00 should be allowed for. In the first few years the money nominally allocated for new infill locations would be best spent on the upgrade of existing CP sites.

4. Upgrade Philosophy

With any system this complex, there are multiple paths towards an end goal. The following matrix was developed to identify both the most cost effective short term and long term solutions. The most cost effective solutions are highlighted in green.

The table below displays the correspondence between the scores and their affect.

Table 2: Effectiveness Comparison Weightings

Legend	Score			
	1	2	3	4
Effectiveness	Temporary improvement (Localised) or Small long term improvement with negative consequences	Small long term improvement (localised)	Significant Long term Improvement (localised)	Significant long term improvement over a wide area or Major localised improvement

	Uprated CP (80 Amp) unit with Auto Control	Auto control CP (no output upgrade)	Anode Bed watering System	New Anode bed in existing easement	Redesigned Anode bed	CP unit upgrade + anode bed redesign	Additional Infill CP system	Linear Anode between existing units	Increased Cross Bonding
Fault	**Effectiveness of upgrade**								
System at maximum voltage (25V)	3	0	1	2	3	4	3	4	1
System at maximum voltage (40V)	2	0	1	2	3	3	4	4	1
watering	1	1	1	2	3	3	2	4	0
System at maximum amperage	3	0	0	0	0			0	0
Frequent Adjustment &/or over output tripping of CP unit	3	2	0	0	0	4	4	0	0
Frequent Critical Failure of CP units in an area (electrical failure or surge effected)	3	2	0	0	0	3	2	0	0
Poor potentials at midpoints despite off potentials around -1200mV at CP site	1	0	0	0	2	1	4	4	1
Adverse Interference on 16"	0	0	1	1	3	3	0	4	4
Total	**16.0**	**5.0**	**4.0**	**7.0**	**14.0**	**21.0**	**19.0**	**20.0**	**7.0**
	Lead Time								
Lead-time	6 Weeks on Unit, 1 week install requires slab and wiring upgrades to be co-ordinated	6 Weeks on unit	2-3 Weeks	4 weeks assuming materials in stock. 12 Weeks if materals required	9 months typical, 3 Months if land holder friendly and materals in stock	9 months typical, 3 Months if land holder friendly and materals in stock	9-12 months due to eng, lands power	12-18 Months Requires USA contactor, lands, two CIPS survey etc	4 Weeks
	Costs								
Costs	$ 37,500.00	$ 21,700.00	$ 4,300.00	$ 41,000.00	$ 73,000.00	$ 101,000.00	$ 144,000.00	$ 985,000.00	$ 10,650.00
Redeployed Equipment Value	-10000	-5000	0	0	0	-10000	0	0	0
Effective Cost	$ 27,500.00	$ 16,700.00	$ 4,300.00	$ 41,000.00	$ 73,000.00	$ 91,000.00	$ 144,000.00	$ 985,000.00	$ 10,650.00
$1000, per effectiveness point. - Lower is more cost effective	1.719	3.340	1.075	5.857	5.214	4.333	7.579	49.250	1.521

Cost assumptions - 2014/2015 Figures	Materials	Internal Labour	Installation Contractor	Maintenance over 12 months	Lands	Power	**Total**
Uprated Auto CP unit 80 Amp	$ 28,000.00	$ 1,500.00	$ 8,000.00		$ -	$ -	**$ 37,500.00**
Auto CP unit 40 Amp	$ 21,000.00	$ 700.00	$ -		$ -	$ -	**$ 21,700.00**
Anode Bed watering - Bulky bins or water tanks	$ 1,600.00		$ 200.00	$ 2,500.00			**$ 4,300.00**
New anodes in existing easement	$ 25,000.00	$ 4,000.00	$ 12,000.00		$ -	$ -	**$ 41,000.00**
Redesigned Anode Bed	$ 43,000.00	$ 5,000.00	$ 15,000.00		$ 10,000.00	$ -	**$ 73,000.00**
CP + Bed upgrade 80 Amp	$ 71,000.00	$ 5,000.00	$ 15,000.00		$ 10,000.00	$ -	**$ 101,000.00**
Additional Infill Cp unit 80 amp	$ 71,000.00	$ 8,000.00	$ 15,000.00		$ 15,000.00	$ 35,000.00	**$ 144,000.00**
Linear Anode	$ -	$ 10,000.00	$ 970,000.00		$ 5,000.00	$ -	**$ 985,000.00**
Cross Bonding (assuming 4 locations)	$ 150.00	$ 1,500.00	$ 9,000.00	$ -	$ -	$ -	**$ 10,650.00**

5. Identified Corrective / Upgrade Works

The below table displays the currently identified corrective works / upgrades for the RBP cp system. While the CP unit data is fairly hard, the anode bed numbers are expected to increase due to;

a) CP unit upgrades will place increased demand on the beds

b) 80 Amp CP units can only drive to 50 Volts, so require proportionally larger bed when running at capacity than a 40Volt/ 40 Amp unit

c) The condition of an anode bed can be masked by how frequently it is getting water and how quickly it drops off when drying out. This data is harder to collect from the field than operating currents and output.

d) No allowance has been made for additional infill anode beds.

Table 3: Identified Required Upgrades

Requires 80 Amp CP unit	Requires 40 Amp CP unit	Requires New Anode bed	No. of Anode beds that can be stop gaped with 40V CP Unit	Other
Completed in FY 2014/2015				
6	6	-	-	-
Priority 1 sites – Causing potentials below protected levels				
3	3	5	5	Improved Cross bonding DN250 – DN400
Priority 2 sites – Can be ok if watered regularly / Potentials ok but no spare capacity				
12 (480k)	7 (7k)	8 (600k)	5 (5k)	5 x duplicate header cables (25K)
Priority 3 Sites – Small amount of spare capacity – will need attention in <5 years.				
N/A	2	3	N/A	

6. Corrective Action Plan

6.1 FY 2014/2015

During 2014, extensive field testing and investigation was completed. From this a number installations were identified as requiring maintenance and a level of priority assigned. CP survey results indicated that the Yuleba to Condamine segment had the worst protection levels after recent upgrades to the Wallumbilla to Yuleba segment.

As such the Yuleba to Condamine section was the primary target of the 2014/15 FY upgrade program. The Primary upgrade was to replace the 6 x 40Amp units currently operating or near capacity in this section.

In addition to this at least one anode bed (MP45.7) needed replacement but land access could not be achieved so it remained flagged for replacement.

6.2 FY2015/2016

The following upgrades were achieved in FY2015/2016, these upgrades were not as originally intended due to issues gaining land access for replacement anode beds. As such purchase of additional CP unit replacements were brought forward for following years.

The following was achieved:

- Installation of new anode beds at MP81 and 83.3
- Purchase of 10 x 80 Amp CP units for install in FY17
- Cross bonding between the DN250 and DN400 at 14 locations between Wallumbilla to Condamine sections.

Table 4: FY15/16 Budget Expenditure

Fiscal Year	# Anode beds	# CP units upgraded		Labour	Equipment	Contractor	**Total**
FY15/16	2	10 purchased		$59,000	$308,000	$133,000	**$500,000.00**

6.3 FY 2016/2017

Ideally the 2016/2017 upgrades would target all of the remaining system limitations. However estimate indicates that would be in the order of $1.2M for a long term solution excluding any additional issue identified by that point.

In addition at least one new CP infill site will be required by this point (Historical average is 1.4 per year) which are currently estimated around $150k per site including power and land requirements.

The existing stock of anode bed materials (carbon backfill and anodes) should have ten beds remaining, depending on the size of upcoming installations. Additional anode beds after this will require purchasing more material first (nominal 12-16 week lead time depending on order size)

The below upgrade plan is proposed below based upgrades based on the information at hand in Aug 2016.

- 4 new 80 Amp units
- 6 New anode beds

Table 5: FY16/17 Budget Projections

Intended Upgrade	Labour	Equipment	Contractor / 3rd Party	Total
Upgrade to 80 Amp CP units at 10 locations	$16,000	$20,000	$30,000.00	$66,000.00
Upgrade 7 x 25 Amp CP units using superseded 40 amp units	$7,000	0	0	$7,000.00
Install 40 Volt / 40 Amp CP units at 1 x 25 Volt CP sites with poor anode beds	$1,000	0	0	$1,000.00
6 x Redesigned Anode Bed using existing materials	$30,000	$140,000	$128,000	$298,000.00
CP interference testing and registration for new / upgraded system	0	0	$45,000	45,000.00
Allowance for 1 new infill site	$6,000	$71,000	$75,000	$152,000.00
Bonding and interference mitigation	$10,000	$5,000	$25,000	$40,000.00
Engineering & Project Management	$20,000			$20,000.00
Total	$100,000.00	$236,000.00	$383,000.00	**$629,000.00**

6.4 FY 2017/2018

The FY2017/2018 upgrades would be to complete the outstanding upgrade identified in March 2015. It's likely however that other priorities may have changed the order of works by this point and the planned should be reviewed as appropriate

Table 6: FY17/18 Budget Projections

Intended Upgrade	Labour	Equipment	Contractor / 3rd Party	Total
Upgrade to 80 Amp CP units at 4 locations	$12,000	$130,000	$32,000.00	$174,000.00
6 x Redesigned Anode Beds	$30,000	$258,000	$100,000	$388,000.00
CP interference testing and registration	0	0	$30,000	$30,000.00
Minor Works (bonding / duplicate header cables etc.)	$10,000	$5,000	15,000	30,000.00
Engineering & Project Management	$20,000			$20,000.00
Total	$72,000.00	$393,000.00	$177,000.00	**$642,000.00**

6.5 FY 2018/2019 through to FY2022

FY 2018/2019 will hopefully begin the return to scheduled end of design life replacement of CP units and anode beds with the exception of the allowance for a new infill sites in this financial year. It is anticipated that this expenditure will continue as a rolling program until a significant change occurs in the pipeline operation or rate of current demand.

Table 7: FY19 onwards Budget Projections

Intended Upgrade	Labour	Equipment	Contractor / 3rd Party	Total
Upgrade to 80 Amp CP units at 4 locations	$12,000	$130,000	$32,000.00	$174,000.00
4 x Redesigned Anode Beds	$20,000	$172,000	$70,000	$262,000.00
CP interference testing and registration	0	0	$25,000	$25,000.00
Misc. minor works (bonding etc.)	$3,000	2,000	$10,000	15,000.00
Allowance for 1 new infill site	$6,000	$71,000	$75,000	$152,000.00
Engineering & Project Management	$20,000	0	0	$20,000.00
Total	$61,000.00	$375,000.00	$212,000.00	**$648,000.00**

Engineering Document

ROMA BRISBANE PIPELINE

STRESS CORROSION CRACKING MANAGEMENT PLAN

Owner		East Coast Grid Engineering QLD		Next Review Date N/A	
Document No		320-PL-AM-0031			
Rev	Date	Status	Originated	Checked	Approved
0	03 Nov 2015	Initial Issue for Use	E Voss	M Brown/ F Carroll	C Bonar 8/12/15

APA Group

TABLE OF CONTENTS

1. INTRODUCTION

1.1. General

This plan documents APA Group's management of stress corrosion cracking (SCC) on the Roma to Brisbane Natural Gas Pipeline (RBP). This plan has been developed to mitigate risks associated with SCC and to satisfy requirements of the RBP Safety Management Study.

This plan forms part of the overall integrity management strategy for the RBP and should be read in conjunction with the QLD Pipeline Integrity Management Plan, document 320-AM-PL-0027, and APA's Expert Guide for SCC management.

The RBP is considered susceptible to SCC and sections 3 & 4 of this Plan summarise the construction details and known history of the pipeline in relation to SCC.

1.2. Purpose and Scope

The purpose of this SCC Management Plan is to:

- Assess and document the susceptibility of the 1969 RBP sections to SCC threat. This includes:
    - DN250 Wallumbilla to Bellbird Park,
    - DN300 Bellbird Park to SEA, and
    - DN200 SEA to Gibson Island

- Document the strategy for management of SCC on the RBP overall (including DN400)
- Outline a strategy for assessing the extent and severity of SCC on the pipeline in the medium term
- Consider SCC mitigation programs to reduce or eliminate the threat of ongoing SCC initiation and propagation over the remaining life of the pipeline.

1.3. Abbreviations

The abbreviations used in this document are listed in Table 2.

Table 1 Abbreviations

Item	Definition
CIPS	Close Interval Potential Survey
CP	Cathodic Protection
C-SCC	Circumferential Stress Corrosion Cracking
DCVG	Direct Current Voltage Gradient (Survey)
DN	Nominal Diameter
EMAT	Electro Magnetic Acoustic Transducer
ILI	In-Line Inspection (aka. Intelligent Pigging)
MAOP	Maximum Allowable Operating Pressure (material property)

Item	Definition
MFL	Magnetic Flux Leakage
MOP	Maximum Operating Pressure (imposed operational limit)
MPa	MegaPascals (pressure unit)
MPI	Magnetic Particle Inspection
PE	PolyEthelene
RBP	Roma to Brisbane Pipeline
SCC	Stress Corrosion Cracking
SCCDA	Stress Corrosion Cracking Direct Assessment
SMS	Safety Management Study
SMYS	Specified Minimum Yield Strength (material property)
UT	Ultrasonic Testing
wt	Wall thickness

1.4. References

Documents referenced in this plan are listed in Table 2 below.

Table 2 Referenced Documents

Referenced Document	
Australian Standard – Pipelines- Gas and Liquid Petroleum: Operation and Maintenance	AS2885.3 - 2012
QLD Pipeline Integrity Management Plan	320-AM-PL-0029
APA Group SCC Expert Guide	-
CEPA SCC Recommended Practices	2nd Edition 2007
PRCI Criteria for Susceptibility to C-SCC	PR-313-113603
NACE SCCDA Standard	NACE SP 0204
Various 1983 documents	Refer RBP Central File index
ALS Report 2011 cracking failure investigation	ALS#4211-1388
APA Report 2011 follow up MPI testing	-
APA Report 2014 failure investigation incl UQMP metallurgical analysis	TRR2014-RP-03
Bureau Veritas 2014 reports on axial cracking (UT and lab)	-

2. PIPELINE SCC BACKGROUND

2.1. General

Pipeline stress corrosion cracking is a known threat to buried pipelines. The APA Group Expert Guide on SCC and the referenced standards and research documents (AS 2885.1, CEPA recommended practices, NACE, ASME, PRCI, etc.) provide relevant background information on SCC mechanisms. A brief summary is provided below.

2.2. Pipeline SCC Classifications

The two forms of SCC that commonly affect transmission pipelines are:

- High pH or classical SCC.
- Near neutral or low pH SCC.

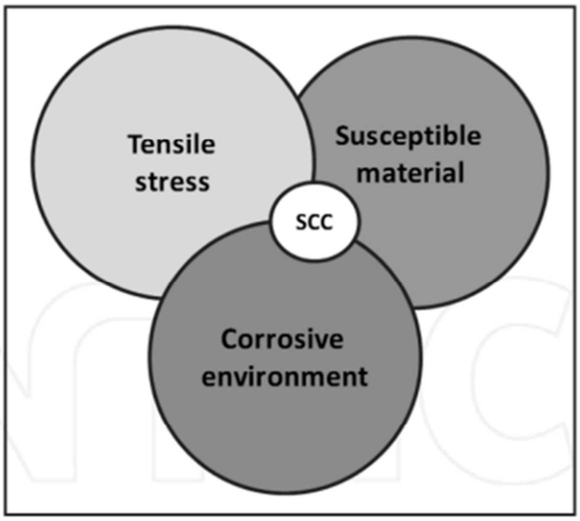
The characteristics of each are compared below:

Table 3 SCC Classification Characteristics

Factor	Near-neutral pH SCC	High pH SCC (Classical)
Location	Associated with specific terrain conditions, often alternate wet-dry soils and soils that tend to disbond or damage coatings	Typically within 20km downstream of compressor station. Number of failures falls markedly with distance from compressor stations.
Temperature	No apparent correlation with temperature of pipe. May occur more frequently in colder climates where CO2 concentration in groundwater is higher	Growth rate increases exponentially with temperature increase
Associated electrolyte	Dilute bicarbonate solution with a neutral pH typically in the range of 6-8	Concentrated carbonate-bicarbonate solution with an alkaline pH greater than 9
Electrochemical potential	-760 to -790mv (Cu/CuSO4). Cathodic protection does not reach pipe surface at SCC sites	-600 to -750mV (Cu/CuSO4). Cathodic protection contributes to achieving these potentials
Crack path and morphology	Primarily transgranular. Wide cracks with evidence of substantial corrosion of crack side wall.	Primarily intergranular. Narrow tight cracks with almost no evidence of secondary corrosion of crack wall.

For SCC initiation and growth to occur there must be three factors present:

- Coating damage or disbondment on susceptible metal.
- An electrochemical environment conducive to either form of SCC.
- Stress above a minimum threshold.



Conditions necessary for SCC occur.

SCC has been detected worldwide on pipelines with:

- Many commonly utilised coatings. (To date there are no known SCC failures on pipelines coated with FBE or Trilaminate)
- Operating stress levels ranging from less than 30% SMYS to at least 80% SMYS.
- All commonly found environments.
- Operating lifetimes from less than 10 years to 50+ years.

Historically the majority of SCC on pipelines has occurred where over-the-ditch coatings were applied.

3. ROMA BRISBANE PIPELINE

3.1. RBP Construction Details

The RBP is a high-pressure natural gas transmission pipeline system owned and operated by APA Group. It transports gas between Wallumbilla and Brisbane and includes numerous receipt and delivery points. The total pipeline system length is approximately 440 km.

The RBP comprises two parallel pipelines for approximately 400 of the 440 kilometres, which are a DN250 (10”) pipeline, and a DN400 (16”) pipeline. The DN400 looping was constructed in stages as demand increased on the RBP. The DN250 pipeline has a MAOP of 7136 kPa, and the DN400 pipeline has a MAOP of 9300 to 9600 kPa.

The DN250 and DN400 pipelines supply the Brisbane metropolitan area by pressure reduction into the Metro DN300 pipeline and the downstream Gibson Island DN200 line and other laterals. The Metro section MAOP is 4612 kPa or below.

The original 1960s pipeline system comprised the DN250, DN30 and Gibson Island DN200 pipelines. These pipelines are the primary subject of this SCC Management Plan.

Table 4 RBP Pipeline Parameters

Characteristic	DN250 Pipeline	DN300 Metro Pipeline	DN200 Gibson Island Pipeline
Construction Date	1967-1969	1967-1969	1967-1969
Commissioning Date	1969	1969	1969
Length of pipeline	397 km	38 km	2 km
MAOP	7136kPa	4612kPa & 4200kPa d/s of Mt Gravatt	4200kPa
Outside diameter	273.1mm	323.9mm	219.1mm
Wall thickness	4.78/5.19/6.35mm	5.16mm	4.78mm
Pipe specification	API 5L Grade X46	API 5L Grade X42	API 5L Grade X46
Pipe manufacturer	Sumitomo Pipe / Stewarts &Lloyds Pipe	Sumitomo Pipe	Sumitomo Pipe
SMYS	46000psi (317MPa)	42000psi (290MPa)	46000psi (317MPa)
Construction method	Open trench with some bored & cased crossings	Open trench with some bored & cased crossings	Open trench with some bored & cased crossings
Design Temperature	0-50deg C	0-50deg C	0-50deg C
Peak Operating Temp	<50deg C	25deg C approx	25deg C approx
Coating Type	Single layer PE tape wrap (nominal 25% overlap)	Double layer Polyken polyethylene tape wrap with 55% overlap	Double layer Polyken polyethylene tape wrap with 55% overlap
Coating Quality	Generally poor, some	Generally fair	Fair

Characteristic	DN250 Pipeline	DN300 Metro Pipeline	DN200 Gibson Island Pipeline
	areas fair		

3.2. RBP SCC History

Due to its age, coating type and application (over-the-ditch PE tape wrap), the deteriorated condition of the coating and a history of three pipeline failures likely associated with SCC, the 1969 RBP pipelines are considered susceptible to SCC.

At the time of writing this plan (2015), a total of three likely SCC failures have occurred on the RBP. All have been in the DN250 section of the original pipeline commissioned in 1969. These failures are as follows:

- 1983: A circumferential crack failure occurred in a section of DN250 pipeline adjacent and parallel to the Bremer River, Ipswich.
- January 2011: the Roma Brisbane Pipeline (RBP) DN250 pipeline suffered a loss of containment event on the Toowoomba Range escarpment adjacent to the Rangeview railway crossing. The leak occurred from a circumferential crack in the pipeline and was discovered following major ground movement.
- June 2014: A failure occurred on the Toowoomba escarpment on 25 June 2014, approximately 140 metres downstream of the 2011 failure. This leak was also found to be a circumferential crack, and associated ground movement had been previously observed in the area.

3.2.1. 1983 Failure – Bremer River

The circumferential cracking failure on the RBP in 1983 at MP241.5 on the bank of the Bremer River occurred after a period of heavy rainfall, and the land on the river bank had slipped laterally to the pipeline. The failure occurred adjacent to a 45° elbow fitting.

The metallurgical examination of this pipe also concluded possible SCC, however stated a predominantly intergranular structure, which is inconsistent with near-neutral SCC and more closely aligned with classical SCC.

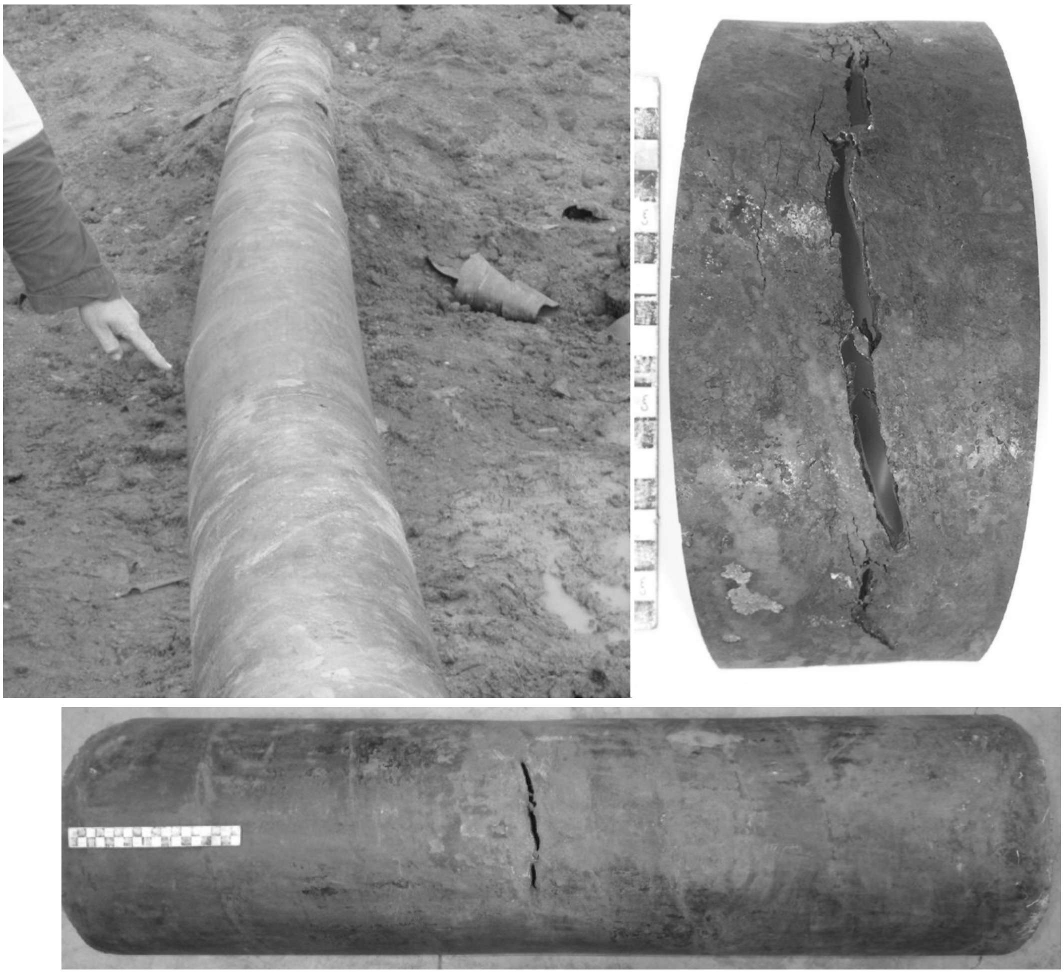
Figure 1 1983 Cracking Failure

3.2.2. 2011 Failure – Toowoomba Range

The January 2011 failure of the RBP at Toowoomba was found to have had pre-existing crack-like features which were suspected to be SCC. The report from metallurgical investigation states that the cracking mechanism is consistent with that of near-neutral SCC. (See ALS Report 4211-1388)

The 2011 failure was associated with severe land movement in the area of the Toowoomba escarpment. A circumferential crack was observed in the side of the pipeline. The failed section of pipe was cut out of the pipeline and metallurgical investigation identified the failure source as a pre-existing crack, which was diagnosed as near-neutral pH SCC. Further fluorescent magnetic particle testing of the surrounding pipe section identified further areas of cracking consistent with Circumferential Stress Corrosion Cracking (C-SCC).

Figure 2 2011 Cracking Failure



3.2.3. June 2014 Failure – Toowoomba Range

The June 2014 failure of the DN250 RBP near Toowoomba was also concluded to have had a pre-existing circumferential crack, again with characteristics closely similar to near-neutral SCC. The section removed and replaced following the June 2014 event included approximately 70m of

DN250 pipe located approximately 31.65km downstream of Oakey Compressor Station. A small sample containing the failure was analysed off site and was found to have been a stress corrosion cracking failure which failed under bending stress.

The remaining removed pipe lengths were tested with black and white magnetic particle testing which identified numerous areas of cracking both circumferential and axial. Subsequent intelligent pigging analysis confirmed the cracking present was within a high strain event.

Figure 3 2014 Cracking Failure

The cracking found on the removed pipe after the 2014 event was both circumferential and axial. The more severe cracks and colonies were circumferential however the extent of axial cracking cannot be discounted. There is now a requirement to assess the pipeline for both circumferential and axial SCC, though it is not known whether the axial cracking was caused by hoop stress from the pipeline pressure or external (possibly torsional) stresses from ground movement.

3.2.4. Additional Cracking Since June 2014

In late 2014 following the repair of the June 2014 failure, one additional area of circumferential cracking was discovered at a strain event near Kingsthorpe (Zimm's Corner) on the DN250 RBP. This was also cut out and replaced with new pipe.

Further investigations of strain areas (detected through IMU inspection and curvature analysis) have uncovered further circumferential and axial cracking. Current dig programs are narrowing down a threshold of strain levels from which cracking can occur. Current knowledge is that circumferential cracking has been found to date only where peak strain magnitude exceeds 0.20%. An empirical threshold of 0.20% bending strain has been established for monitoring, and a threshold of 0.30% bending strain for excavation and inspection.

In the 2015 excavation program a number of strain events, dents and corrosion features were excavated and all exposed pipe 100% inspected for evidence of cracking. No cracking was detected with the exception of:

- Dents with associated gouging in the DN250 pipeline at one dig location (MP 31 – Yuleba area). Cracking was found throughout the dent/gouge area. This section of pipe has been removed from the line and investigations are ongoing to determine the nature of the cracking.
- One small colony of apparent axial SCC (3 individual cracks) in the Condamine-Kogan section with a maximum crack length of 4mm and a peak depth of 0.12mm ground out of the pipeline. This excavation was undertaken to inspect a 0.206 magnitude strain event (Dig#40).

3.2.5. Other Pipeline Events

A landslip event occurred in 2012 on the Marburg Range, causing the RBP DN250 pipeline to move over 1m down the hillside. This pipe was decommissioned and replaced by a horizontal directional drill through the mountain. During the preliminary investigation, a small sample of the excavated pipe was inspected by MPI to look for cracking. None was found despite the presence of plastic bending deformation in the pipe.

Note – in 2015 another Australian pipeline operator reported a pipeline failure by SCC on a tape wrap coated pipeline in South Australia of similar vintage to the RBP.

4. ASSESSMENT OF RBP SUSCEPTIBILITY

4.1. High pH (Classical) SCC

There had not been any instances of high-pH SCC on the RBP before the events on the Toowoomba Range, and from assessing those failures it does not appear either of the 2011 or 2014 failures were High pH SCC.

However, in accordance with APA's Expert Guide, the RBP is still considered susceptible to high pH SCC. The high-pH SCC risk profile has not increased dramatically as a result of 2014 events, however ongoing management by direct assessment and opportunistic inspection is included in this management plan. Metallurgical assessment of any cracking detected in the future on the pipeline is required (when pipe is cut out) to determine the type of cracking present. Replication metallography can be considered for in situ assessment.

Direct assessments for SCC have been performed at the highest risk area, downstream of the Wallumbilla Hub where the RBP DN250 pipeline was subject to high temperatures from compression and pressure cycling for over 20 years. These assessments (approximately 400m in total so far) have yielded no findings of SCC despite both coating absence and shielding.

Regardless, the risk of high-pH SCC cannot be eliminated considering the age of the RBP. Management of this risk is included in the ongoing management plan.

4.2. Low pH (Near-Neutral) SCC

The RBP has suffered recent failures attributed to Near-Neutral SCC at locations with high bending strains present. Axially orientated near-neutral SCC has also been detected on the pipeline. The susceptibility of the pipeline has been proven. To assess areas that may be at risk, the factors contributing to near-neutral SCC must be evaluated.

The RBP failures to date appear to be related to a sub set of near-neutral SCC known as circumferential SCC. Circumferential SCC occurs when a susceptible pipeline, coating and environment occurs in combination with high longitudinal/bending stresses.

4.2.1. Stress – Longitudinal

Longitudinal stress on the pipeline is the primary stress direction associated with circumferential cracking, such as the failures observed in the RBP. Longitudinal stress can be increased by direct longitudinal forces or, more severely, by imposed bending.

Possible sources of longitudinal stress on the RBP include:

- Land movement
- Subsidence or washout
- Dents/Impacts
- Residual stress from construction (misalignment at tie-in or ambient temperatures)

Thus far, land movement through landslip or creek erosion has caused the failures and no confirmed evidence of SCC has been found from the other listed sources (Note: classification of cracking from a combined dent/gouge still to be confirmed.). They will however still be considered risk factors for the pipeline.

4.2.2. Stress – Hoop (Circumferential)

Hoop stress contributing to axial cracking is predominantly from pipeline internal pressure and pressure cycling. The RBP does undergo pressure cycling on a regular basis however it is not extreme (within a 1000kPa range on a weekly basis).

At the time of preparation of this plan, axial cracking has been observed within the Toowoomba Range failure area. Axial cracking severity was evaluated as Level II according to the CEPA guidelines.

The RBP is considered susceptible to axial SCC based on its age and coating type.

4.2.3. Materials

The 1960s line pipe in the RBP meets susceptibility criteria for SCC. Interestingly, all the SCC failures to date have occurred on heavy walled pipe (6.35mm wt.) however this may be merely because the unstable terrain was considered prior to construction hence the installation of heavier wall pipe in these locations.

Since the X46 6.35mm wt. material is susceptible, all line pipe material on the DN250 and DN300 pipelines is considered at risk.

The single wrap over-the-ditch PE tape coating used on the DN250 line is very much at risk of SCC as it is easily disbonded. After over 40 years of service, the coating has been subject to temperature, pressure, soil and moisture fluctuations. This has caused some areas of coating to disbond completely (forcing cathodic protection into effect) and other areas to shield (or tent), which is a major concern for SCC.

4.2.4. Corrosive Environment

For a near-neutral pH environment to cause SCC, the following factors are usually present:

- Groundwater
- CO_2 (decay of organic matter)
- Sulfate-reducing bacteria formed under disbonded coatings.
- Existing low level general corrosion
- Coating shielding from CP
- Low pH typically between 6 and 8

5. SMS RISK ASSESSMENT SUMMARY

5.1. Safety Management Study Status - 2015

SCC threats have been considered in the RBP AS2885 Safety Management Study, as updated during 2014-15 following the Toowoomba Range events and 5-yearly SMS reviews. Table 5 below summarises the SCC threats and their risk rankings. Relevant corrective actions are listed in Table 6.

The RBP SMS Database should be referred to for the latest status of SMS threats and actions.

Table 5 Current RBP SMS Threats associated with SCC

Threat ID	Threat	Initial Risk Rank	Mitigating Actions	Ongoing Risk Rank	Comments
45	Stress corrosion cracking – Axial (non-location-specific)	Intermediate	75, 98, 136	Intermediate	Catastrophic / Hypothetical – refer to ALARP assessment
73	Undetected cracking (non-location-specific)	None	58, 98	None	Threat deemed currently acceptable with mitigating actions, not evaluated
174	Ongoing slope instability (medium - long term) leading to failure by circumferential SCC (Toowoomba)	Low	64, 65, 66, 75, 76, 77, 83	Low	Severe/Remote for ignited leak; strain events now understood and managed
218	Circumferential cracking in DN250 and DN300 pipelines (1969) due to strain on pipe	Intermediate	98, 137, 138	Low	Risk can be revised based on results of actions

Table 6 Current RBP SMS Actions associated with SCC

Action ID	Action	Action By	Status (2015)
64	Slope stability monitoring (Toowoomba Range) - review frequency of survey monitoring and also review number of measurement points, including check after major rain events. 2014 Update: Consider regular LIDAR survey and/or XYZ pigging and strain analysis and include in SCC management plan. Consider geotechnical inclinometers with geotechnical specialist input.	QLD Engineering	Slope management plan being developed – monthly surveys continuing
65	Slope stability risk assessment - consider risk evaluation	QLD	Included in

Action ID	Action	Action By	Status (2015)
	of longer term slope and pipeline failure after completion of geotechnical assessment and stress analysis.	Engineering	slope management plan above
66	Slope stability advice - extend scope of geotech advice to include all parts of the Toowoomba Range where slope failure could impact on the pipeline, including particularly the adjoining railway sections and possibly Main Roads. July 2014: Review effectiveness of drainage with geotech and hydrological advice, and consider any possible improvements.	QLD Engineering	Included in slope plan
75	Toowoomba Range 2014 - Review stress analysis report and pigging data and site measurements from cutout of defect. Develop a management strategy for this type of defect in this area (potentially SCC), considering ground movement, MFL ILI throughout slope area, XYZ data, leak surveys, re-hydrotesting etc. Have management plan in place prior to recommencing operation of the section. Consider a business case for replacement/relocation of the section.	QLD Engineering	SCC management plan developed (this document).
76	Toowoomba Range 2014 - Consider implementing automatic leak detection in SCADA for the RBP.	QLD Engineering	Not implemented yet - new Online Sim may provide this
77	Toowoomba Range 2014 - Consider hydrostatic test of DN250 Oakey-Gatton or sub-section, and/or temporary MOP restriction, and/or increased patrol frequency until hydrotest can be completed. Resolve this prior to returning the section to service.	QLD Engineering	Hydrotest not warranted yet. Consider in future as part of SCC mitigation.
83	Toowoomba Range 2014 - Excavate next-highest magnitude strain event (0.301% near railway). Inspect and review prior to returning to service.	Francis Carroll	Completed (section had cracking and was cut out)
98	Finalise SCC Management Plan and implement any associated actions.	Francis Carroll	This document
136	SCC Mitigation - Review wall thickness and location class to identify areas of thin wall DN250 in populated locations. Assess alternative options to mitigate risk in these areas.	Michael Brown	In progress. All DN250 pipe from Karalee to Bellbird Park is 6.35 mm.

Action ID	Action	Action By	Status (2015)
137	SCC Circumferential - complete digup and MPI inspections of critical identified strain events as per the management plan	QLD Engineering	Completed this program of strain digs. Further digs ongoing.
138	SCC Circumferential - complete XYZ pigging and strain analysis of remaining 2 x DN250 sections	QLD Engineering	Completed.

6. MITIGATION ACTIONS

This section describes the management actions that may be implemented as required by APA Group to mitigate SCC risks on the RBP.

Overall, due to the presence of known SCC failures as well as the age and coating type of the 1969 RBP, APA's Expert Guide requires this SCC management plan to be implemented and to include mitigation actions as well as direct assessment and opportunistic inspections.

Possible mitigation actions and their applicability to the RBP are described in the following sections.

6.1. MOP Management

MOP restrictions reduce the risk of failure of axial cracking by:

- Reducing hoop stress on the pipe wall, lowering the driving stress at the crack tips.
- Increasing the tolerable depth before failure.
- Increasing the critical defect length.

MOP restriction has limited impact on reducing failure risk of circumferential cracking as longitudinal strain is the driving force for cracking of this nature.

Use of MOP restrictions is not considered to be an acceptable mitigation method for SCC, unless it can be established stress levels have been reduced to the extent where crack growth is arrested.

Where MOP restrictions are imposed to manage SCC risk, the MOP will need to be regularly reviewed to allow for SCC growth unless effective mitigation can be achieved.

Based on axial cracking severity found to date in the RBP of Category II, no ongoing MOP restrictions are currently required for SCC mitigation.

6.2. Hydrotesting

Hydrostatic testing of pipeline segments can be used to destructively detect sub critical cracking defects and prove the pipeline is fit for service at the established MOP.

Hydrostatic pressure testing is primarily useful for axial cracking and has limited applicability to circumferential cracking.

Routine hydrotesting is considered to be an effective axial SCC mitigation method, with re-test intervals determined based on crack growth rates, test pressures and MOP. Disadvantages include:

- Significant impacts on operations due to outages of pipeline segments.
- Large volume water management.
- SCC present is not removed/repaired unless test failure occurs.

As part of SCC mitigation on the DN250 pipeline, hydrostatic testing will be considered. An engineering study is required to assess feasibility of hydrotesting each section. It is possible to remove the DN250 pipeline sections from service for testing, due to the presence of the DN400 looping.

6.3. In Line Inspection

In line inspection (ILI) with dedicated crack detection tools, with follow up excavation and repair, is considered to be an effective axial SCC mitigation method. Options currently commercially available are:

- Ultrasonic crack detection tools – good crack detection capabilities but require use of a liquid couplant. Currently available in DN250 and may be a viable mitigation method for the looped DN250 pipeline sections. This may be difficult to undertake in hilly sections such as Toowoomba.
- EMAT crack detection tools – currently available down to DN300, not DN250; no liquid slug needed but lower detection capability than ultrasonic tools. Can detect coating disbondment. Where EMAT inspections are practicable they are the preferred APA mitigation and monitoring method for pipelines with axial SCC. Note that DN250 EMAT tools may be developed in future by ILI vendors; this depends on redesign of the EMAT sensors so they can be accommodated in a smaller diameter tool.

Other ILI tools can assist in development of SCC direct assessment programs by identifying locations of higher SCC risk. These include:

- Conventional metal loss (MFL) tools - do not detect axial cracking but may identify partially opened circumferential cracks. High resolution tools capable of detecting low level metal loss that can be associated with near-neutral SCC. Currently routinely used in RBP.
- Axial MFL tools – may detect partially opened axial cracks and longitudinal gouges that can have associated cracking. Not currently used in the RBP system.
- Geometry (calliper) tools – detect dents, bends and other geometric features that are known to be susceptible to SCC. Currently routinely used in RBP.
- XYZ (inertial mapping / gyro) tools – can detect areas of curvature and strain on the pipeline e.g. due to ground movement. Strain change analysis can detect changes in shape/curvature/strain between ILI runs. Effective in identifying locations with higher likelihood of circumferential SCC. Currently routinely used in RBP.

6.4. Indirect Assessment

Indirect assessment can be used to identify areas of the pipeline that may be more likely to be affected by SCC. This technique is most useful where ILI techniques are not suitable. It is used where alternative monitoring methods are not practicable to select locations for excavation and direct assessment for SCC.

6.4.1. Current Risk Factors for Indirect Assessment

Based on industry guidelines and current RBP knowledge, areas of increased likelihood of SCC along the pipeline include:

For circumferential SCC:

- Any areas identified as containing excessive strain from ILI data
- Any areas with similar ILI signatures to the past failures
- Known land movements
- Large areas of subsidence (e.g. Mine collapse)
- Large washouts and watercourse crossings
- Slopes greater than 10 degrees
- Dents
- Crossing and tie in locations where high residual construction stresses may be present.
- Areas with marginal or under protected CP levels

For axial SCC:

- Areas of high pressure and cyclic loads

- Dents and pipe wall opposite dents
- Areas with marginal or under protected CP levels
- Locations with low level metal loss (near-neutral)
- Locations within one valve section from compressor stations (high pH)

Due to the limited amount of SCC detected on the pipeline additional risk factors such as soil type or site position may become evident as further information comes to hand from ongoing direct assessment and ILI programs.

6.4.2. Additional Information Gathering

Coating Disbondment

Coating disbondment is one of the major factors in near-neutral pH SCC susceptibility. Use of EMAT ILI tools shall be considered where feasible, to detect areas of coating disbondment.

An alternative technique involves correlation of areas of external general corrosion (detected by MFL ILI) with areas of coating classified as “good” (i.e. no indication of coating defect) by DCVG or CIPS. A lack of coating defects visible to DCVG technique suggests the corrosion would be occurring underneath disbonded coating which is shielding the CP current.

On the RBP it is possible that this particular investigation will be very difficult due to the large number of coating defects and generally poor coating condition particularly in areas of ground movement. Historically on the RBP, APA Group has not undertaken routine DCVG or CIPS surveys in piggable areas. The preference is to spend excavation effort on known metal loss defects.

Given the now increased SCC risk profile, consideration should be given to trialling DCVG and CIPS surveys at least in identified higher-risk locations. This has been added to the management plan.

Ground Movement Monitoring

A ground movement monitoring plan for the RBP is being developed for high risk areas. Information obtained from monitoring of ground movement in areas of known instability will provide additional information for prioritising direct assessment programs for circumferential SCC.

Materials Testing

Due to the age of the RBP there is limited data available on the original line pipe materials. Ongoing collection and cataloguing of line pipe data will assist in understanding any differences in SCC risks based on pipe mill source, wall thickness, etc. and will also have other benefits such as better understanding of fracture control properties.

Whenever any RBP line pipe is cut out for any reason, the material shall be retained and metallurgically investigated in a suitable laboratory.

Specific actions recommended are:

- All decommissioned RBP pipe sections should be reviewed and additional materials testing carried out as required. At a minimum this is to include tensile tests and fracture tests of the base metal and ERW weld. (Charpy V-notch and drop weight tear testing – refer to RBP Fracture Control Plan for further requirements)
- Crack testing of any pipe sections or coupons previously removed from the pipeline that have not been previously 100% inspected, including 4.78mm wall thickness pipe removed from the Marburg Range. Crack testing shall be undertaken by Magnetic Particle Inspection (black and white or fluorescent, after blasting), or phased array eddy current testing. Where cracking is indicated the affected area shall be buffed/linished to remove any

material peened by blasting and black and white MPI undertaken to enable documentation and assessment of cracking.

- Existing samples of the 6.35mm wt. pipe (ex Toowoomba Range) should be compared against samples of thinner-walled pipe of the same pipeline to ascertain any discernible differences between the material properties which may influence SCC susceptibility.

All pipeline cut-out samples containing SCC should undergo the following additional testing:

- Optical microscopic examination of cross sections through any cracks
- Metallographic testing to establish morphology, including crack tip examination for interaction with grain boundaries
- Cutting or breaking open of selected cracks
- Scanning electron microscopic examination of crack surfaces
- Preparation of a detailed investigation report.

Before undergoing destructive testing, engineering staff should consider whether particular cutout samples may be of use to ILI providers as test pieces for developing new tool capabilities.

6.5. In Situ SCC Direct Assessment

Direct assessments by non-destructive examination of exposed pipeline surfaces are a routine part of the RBP integrity management programme. SCC direct assessment shall be conducted on all excavated / exposed pipelines on the RBP and shall include:

- 100% coating removal and MPI or phased array eddy current testing for crack detection
- Detailed measurement, photography and recording of crack locations, lengths and widths
- Determination of crack interaction lengths
- Step wise grinding and/or phased array ultrasonic testing for determining crack depths.
- Calculation of failure pressures of axial crack colonies to determine severity of cracking.
- Establish crack location in relationship to bends and bending strain
- Coating samples, and any liquids retrieved from beneath the coating, should be tested for pH and chemical composition
- Soil and groundwater testing shall also be considered (pH and electrical resistivity)

In addition, SCC direct assessments will be conducted at on an ongoing basis at sites identified through the indirect assessment process described above.

6.6. Coating Refurbishment

Large scale coating refurbishment with a non-shielding high quality coating is an effective SCC mitigation measure, however it is not considered economically viable on the RBP as costs would be equivalent to or higher than replacement with new pipe.

Refurbishment of short high risk sections of the line shall be considered, particularly to mitigate circumferential SCC risk in known strain events or locations with soil movement.

Whenever the pipeline is exposed for inspection tape wrap coatings shall be removed and replaced with approved high build epoxy coatings to prevent future SCC initiation.

6.7. Pipe Abandonment or Replacement

Pipe abandonment or replacement are effective in mitigating SCC risk. These options will be considered if extensive Category II or higher cracking is discovered on any of the 1969 vintage pipe.

6.8. Summary of Management Techniques

The table below summarises the SCC management techniques discussed and their applicability to the RBP.

Table 7 SCC Management Techniques

Technique	Relevant to			Applicable for RBP
	High-pH	**Near-neutral axial**	**Near-neutral circumferential**	
MOP restriction	X	X		Yes – if Cat III or higher cracking is detected
Hydrostatic test	X	X		Not currently – to be considered as part of mitigation programme for Category II cracking
ILI – Geometry and MFL	-	X		Yes – dents susceptible to SCC; low level metal loss correlated to near neutral SCC
ILI – XYZ			X	Yes – strain assessment to be undertaken in conjunction with all ILI inspections
ILI – UT	X	X		Not currently – to be considered for DN250 and DN200 sections as part of mitigation programme for Category II cracking
ILI- EMAT	X	X		Yes – Currently available DN300 and above only. To be used in RBP Metro DN300.
CP Maintenance / Upgrades	X	X	X	Yes – but near-neutral tends to occur under fully shielded coating (See below)
Indirect assessment	X	X	X	Yes – used to prioritise SCCDA excavation program (e.g. correlate CIPS/DCVG with MFL metal loss results)
SCC direct assessment	X	X	X	Yes – primary method for SCC assessment until reliable ILI available. 100% surface NDT not practicable.
Ground movement monitoring			X	Yes – in high risk areas (Survey monuments; Lidar; strain gauges)
Laboratory investigations	X	X	X	Yes – routinely done on cut-outs. Consider additional ERW seam Charpy tests as available
Excavate and recoat pipeline	X	X	X	Yes – High risk short sections only. Large scale programs not economically viable.
Abandon or replace pipe	X	X	X	Not currently – to be considered as part of mitigation programme as a last resort.

7. MANAGEMENT PLAN

7.1. CEPA Recommendations

Based on the finding of Category II axial SCC, the CEPA guidelines recommend the following actions:

- Perform an engineering assessment to determine maximum crack growth rates, mechanisms and other factors
- Determine the appropriate time frame for mitigation activities
- Undertake SCC mitigation activities, within 4 years of discovery of SCC or within the appropriate time frame determined by the engineering assessment. Mitigation should include at least one of:
  - SCC hydrotesting and repair of failed defects
  - Reliable in-line crack inspection and repair of SCC defects
  - 100% surface NDT for SCC and repair of SCC defects
  - Replacement of pipe segments.

7.2. APA Management Plan for RBP

APA has developed a management plan for SCC in the RBP based on the observed cracking in the pipeline to date. The CEPA guidelines have been taken into account as well as APA's experience on other pipelines in Australia.

7.2.1. Circumferential Cracking

APA's plan to manage circumferential cracking includes regular investigation of high-risk sections of piping. This will be done through In-Line-Inspections using MFL and XYZ tools together on a regular basis; initially every 5 years. Future re-inspection intervals will be determined on the basis of growth analysis and assessment in accordance with CEPA and AS 2885.3 guidelines. The ILI runs will provide data to perform strain analysis and identify those high-risk areas where the pipe material is under stress, which can lead to circumferential cracks.

These areas will then be excavated, inspected, and recoated which usually covers two mitigation approaches; confirming the presence or absence of cracks (and their repair) and the removal of any soil load causing strain on the area.

Excavation and inspection as above will also be performed on any areas of confirmed ground movement, as identified by ongoing geotechnical monitoring through areas of past or potential land slip.

To address the risk factor of shielded coating causing widespread low-level corrosion which correlates with circumferential cracking in stressed areas, data from above-ground coating surveys will be compared to the ILI results for corrosion. This gives areas where the pipe may be shielded and will help prioritise sections of pipe for SCCDA.

7.2.2. Axial Cracking

Axial cracking is currently being managed according to CEPA guidelines and is an ongoing program. The current mitigation plan involves prioritised SCCDA programs, and ILI.

Due to the absence of any cracking in excavations to date in high risk locations for High-pH SCC (high temperatures, poor coatings, pressure cycling), management of high-pH SCC is currently addressed with 100% crack detection NDT in all excavations.

Other axial SCC instances are being managed by identifying and mitigating risk factors. The 2015-16 excavation and repair program identifies dents as stress raisers which can lead to axial, circumferential and radial (from dent centre) cracking. The current program will excavate approximately 100 dents and inspect these for cracking before repair and recoat.

In the DN300 Metro area, EMAT ILI will be performed in 2016 to locate and size any cracking. Dependent on results there will be options of repair programs, large-scale recoating, and pipe replacement considered.

EMAT ILI for the DN250 sections is not yet available, and results of SCCDA will determine requirement, frequency and viability of UT ILI in these areas. Further data is required on cost estimates for these activities before the steering committee can provide informed guidance.

The following table sets out APA's SCC management plan for the RBP system.

Budgets for the SCC mitigation activities will be separately developed as part of APA's ongoing Opex and Capex programming.

Table 8 SCC Management Plan 2015-2025

Financial Year	**Inspection/ Monitoring**	**Planning/Development**	**Field Works**
2014	Close Interval Potential Survey	Ground monitoring	Excavation Program and Coating Refurbishment - High-pH SCC Mitigation Coating Refurbishment Ongoing CP Upgrade programme
2015	ILI (GE) XYZ, MFL, Strain Close Interval Potential re-Survey	Planning for Strain Assessment	Excavation Program and Coating Refurbishment - Strain High Priority digs from FY14 ILI Results
2016	EMAT ILI in DN300 Metro Pipeline Trial indirect assessment (DCVG, CIPS) to locate areas of shielding disbonded coating with metal loss	Study/scoping for installation of ground monitoring (inclinometers, strain gauges, LiDAR) Engineering assessment for crack growth rates and mitigation timeframes	Excavation Program and Coating Refurbishment - Dents, Metal Loss and Strain High Priority digs from FY15 ILI. Ongoing CP Upgrade programme
2017	Ongoing ground monitoring implementation using inclinometers, strain gauges, LiDAR as per Slope Management Plan	Planning for possible hydrotest or ultrasonic wet ILI Assess Metro EMAT reinspection interval based on 2016 run and digup verifications	Excavation Program and Coating Refurbishment - Dent and Metal Loss Priority digs from FY15 ILI, SCC Digs from EMAT ILI
2018	Hydrotest or Ultrasonic Wet ILI Wallumbilla- Yuleba	Review possible development of DN250 EMAT tool based on Metro ILI and Excavation results	Excavation Program and Coating Refurbishment – ongoing Dig Program developed from FY15 ILI and EMAT FY16 ILI
2019	XYZ, MFL, and Caliper ILI (Assuming 5 year reinspection from 2014)	Plan Hydro/ILI Other sections depending on prior results Curvature strain analysis including comparison to previous runs	Excavation Program and Coating Refurbishment – Digs from UT ILI or ongoing programme
2020	Hydro/UT ILI on remaining sections	Revise EMAT decisions and all ILI frequency	Excavation Program and Coating Refurbishment – Digs from UT ILI or ongoing programme
2021	EMAT ILI DN300 Metro Area	Plan for Hydrotest or UT ILI or	Excavation Program and Coating Refurbishment

		replacement	
2022-2025	UT/EMAT ILI, remaining sections XYZ/MFL ILI All Sections	Future planning	Excavation Program and Coating Refurbishment

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Engineering Systems Development

EXPERT GUIDE

STRESS CORROSION CRACKING MANAGEMENT

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1. INTRODUCTION

1.1. Purpose and Scope

This guide covers the integrity management of APA owned and operated transmission pipelines in relation to the threat of Stress Corrosion Cracking (SCC).

This guide covers the condition monitoring, assessment and mitigation processes and procedures employed to manage the threat of SCC and mitigate risks to the public, operating personnel and pipeline operability.

The purpose of this guide is to:

- Support development of pipeline specific integrity management plans (PIMP) that adequately address the threat of SCC.
- Outline the strategy for integrity management of SCC on pipelines to ensure ongoing safe and reliable pipeline operation.
- Outline the condition monitoring program and procedures for assessing the extent and severity of SCC damage to pipelines
- Document the processes and procedures used for assessing the threat of SCC damage and controlling associated risks
- Document the processes and practices used for SCC repair and mitigation of identified threats.
- Outline the SCC mitigation programs to reduce or eliminate the threat of ongoing SCC failure over the remaining life of pipelines.
- Demonstrate that APA SCC integrity management processes comply with best industry practices and are undertaken in accordance with, but not limited to, AS2885.3 requirements.

This guide does not cover:

- General pipeline integrity management – Refer to the APA Pipeline Management System and pipeline specific PIMPs
- General corrosion management of the pipeline and associated cathodic protection systems
- Integrity of above ground facilities
- Environmental management of the pipeline easement
- Landowner management
- Specific prescribed schedules or dates for inspection or mitigation activities.
- Alternative strategies involving major replacements or upgrade works.

This guide is a living document to be reviewed 4 yearly and may be amended from time-to-time. It is intended that the guide reflects the most up-to-date knowledge and information regarding in house, national or international practice in condition monitoring, assessment and mitigation practices.

2. GENERAL

The guide focuses on pipeline SCC risk control and SCC mitigation activities to ensure continued safe operation of the pipelines.

2.1. Objectives

The guide sets out the SCC condition monitoring, assessment programs and associated integrity management activities required in order to:

- To protect the safety of the public and operating personnel;
- To maintain security of supply to the market;
- To protect the environment and private property from damage; and
- To maintain the reliable safe operation of the pipeline system.

2.2. Basis

APA Group aims to utilise international best practice in the integrity management of SCC on its pipelines. However, as SCC is a pipeline specific phenomena, specific processes and procedures will need to be developed or adopted for individual pipelines.

APA Group generally follows the CEPA [Ref 1] guidelines for SCC management in conjunction with best available international practices including ASME B31.8S, and published literature by the Australian Pipeline Industry Association (APIA), US DOT, API, PRCI and EPRG.

APA group is actively involved in ongoing industry research projects relating to SCC integrity management, continually incorporating new information and techniques.

2.3. Current Pipeline SCC Condition Knowledge

The two forms of SCC that commonly affect transmission pipelines are:

- High pH or classical SCC, characterised by intergranular crack growth.
- Near neutral or low pH SCC, with a trans-granular crack morphology.

For SCC initiation and growth to occur there must be three factors present:

- Coating damage or disbondment, typically with field applied coatings
- An electrochemical environment at the pipe wall conducive to either form of SCC.
- Stress above a minimum threshold, typically 60% SMYS[1].

SCC has been detected worldwide on pipelines[2] with:

- All commonly utilised field applied coatings.
- Operating stress levels ranging from less than 30% SMYS to 80% SMYS.
- All commonly found environments.

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[1] NACE SP0204-2015

[2] Coating deterioration as a precursor to SCC GRI-04/0099

- Operating lifetimes from less than 10 years to 50+ years.

It is thought that surface preparation techniques is a major factor in the low susceptibility of modern pipelines with factory applied coatings. Pipe wall blasting to remove mill scale in surface preparation produces desirable effects reducing subsequent coating disbondment and developing a compressive pipe wall surface stress. Lower operating temperatures and pressures, and low levels of pressure fluctuation also provide beneficial impacts.

To date there have been no documented failures on pipelines coated with fusion bonded epoxy (FBE) or Tri-laminate coatings, however one instance where FBE coating damage by a rock was shielded from CP current protection has been reported in the industry[3].

3. RISK MANAGEMENT

Risk management is a key driver of any SCC integrity management process. The primary aim is to ensure the pipeline operates at an acceptable risk level in accordance with best industry practices and regulatory guidelines. The purpose of this guide is to outline the processes and procedures necessary to ensure that the threat of SCC is fully identified and that appropriate controls are implemented to maintain the residual risk at acceptable levels.

Qualitative risk assessment in line with AS2885 is to be utilised for the following aspects of SCC integrity management:

- Prioritisation of pipeline sections for scheduling of coating condition monitoring, pipe wall integrity assessment and implementing mitigation actions;
- Assessment of benefits derived from mitigation actions;
- Determining the most effective mitigation measures for the identified threats;
- Assessment of the integrity impacts of modified inspection procedures, intervals and equipment;
- Resource allocation.
- Identification and prioritisation of specific pipeline threats arising from condition monitoring and assessment activities.

Quantitative risk assessment methods may be utilised to further manage risk on SCC affected pipelines where sufficient information is available to develop appropriate models.

[3] Emat Users Conference – May 2102

4. SCC INTEGRITY MANAGEMENT PRACTICES

4.1. Introduction

APA Group endeavours to utilise best international industry practices in managing SCC risk and pipeline integrity. APA Group utilises where possible specific asset condition knowledge to improve upon the international guidelines, which by necessity are overly-conservative to suit all scenarios.

The APA SCC integrity management processes have therefore adapted valuable learning's from overseas, but customised with local skills, knowledge and techniques.

International SCC integrity management guidelines that have been used to provide direction in developing this guide are summarised briefly below.

4.1.1 ASME B31.8S 2014

The American Society of Mechanical Engineers (ASME) standard B31.8S deals with the integrity management of gas pipelines. One of the threats considered is SCC.

Paragraph A3 of B31.8S describes an integrity management plan to assess and mitigate the threat from high-pH SCC and, by extension, of near-neutral pH SCC.

A list of criteria is provided for assessing the threat from high-pH SCC includes:

- operating stress >60%
- operating temperature >38 ^{0}C
- distance from compressor station < 32 km
- age > 10 years
- all coatings other than FBE or liquid epoxy

A similar set of criteria is proposed for near neutral pH SCC, with exception of the effect of temperature. These criteria are based on operating experience and include no guidance for estimating crack growth rate for determining re-inspection intervals for high-pH and near-neutral pH SCC. No specific guidance for managing circumferentially orientated SCC (C-SCC) is provided.

Note: The operating stress, temperature and distance from compressor stations criteria have not proved to be significant factors for crack development and growth on the APA Moomba-Wilton Pipeline and may not be relevant to other APA pipelines.

4.1.2 NACE SP0204-2015

The NACE International Standard Practice (SP) for SCC direct assessment is used to identify SCC susceptible sites using a four-step Direct Assessment methodology.

The SP describes the overall SCCDA process, from threat assessment, through collection of data, identification of candidate dig sites, prioritisation and selection of dig sites, indirect assessment, direct examination, post assessment, and reporting.

The SP lists a large number of factors to consider when prioritising susceptible segments for indirect and direct examination. Many of these factors are based on operational experience alone.

NACE SP0204 offers no guidance as to how frequently pipeline segments should be "re-inspected" using either the DA process or other techniques, such as ILI or hydrostatic testing.

Note: As with ASME B31.8S the operating stress, temperature and distance from compressor stations criteria have not proved to be applicable on the APA Moomba-Wilton Pipeline and may not be relevant to other APA pipelines. Ambient temperature was found to have a significantly more significant impact over a wider area.

4.1.3 CEPA SCC Recommended Practices 2nd Edition

The Canadian Energy Pipelines Association (CEPA) SCC Recommended Practices (CEPA 2007) deals exclusively with near-neutral pH SCC and covers all aspects from detection, through assessment, mitigation, and prevention.

Section 5 deals with SCC investigation programs and includes a detailed listing of the various factors that have been found to correlate with near-neutral pH SCC. These factors are categorized as coating type and coating conditions, pipeline attributes, operating conditions, environmental conditions, and pipeline maintenance data. As for the NACE SP and ASME B31.8S, these factors are largely based on field experience. No specific guidance on re-inspection intervals is provided other than that the maximum reassessment interval should be 10 years.

Chapter 12 of the recommended practices also provide guidance on managing circumferentially aligned, near neutral pH cracking (C-SCC) as detected on the RBP in 2011 at Toowoomba

4.1.4 API RP579

The American Petroleum Institute Recommended Practice 579 (API 2000) is a fitness for service standard that presents various assessment techniques for pressurized equipment in the refinery and chemical industries. It, therefore, covers a wide range of equipment and is not specifically directed towards hydrocarbon-containing pipelines.

It describes assessment procedures for various defect types and processes, including: general metal loss, local metal loss, pitting corrosion, blisters and laminations, weld misalignment and shell distortion, crack-like flaws, and creep. Estimation of the crack growth rate is required for any component that is used in a service environment that supports SCC (or other types of cracking).

Because the RP579 is not specifically directed towards pipeline operation, the example SCC crack growth rate expressions that are presented are not appropriate for predicting the rate of external cracking of underground pipelines. Appendix F of RF579 lists various fatigue and SCC crack growth expressions, but none of these are suitable for predicting the rates of high-pH or near-neutral pH SCC.

4.1.5 PRCI Final Report PR-377-063528

This report published in 2010 'Development of Guidelines for Identification of SCC Sites and Estimation of Re-inspection Intervals for SCC Direct Assessment' the guidelines are designed to complement and supplement existing SCC Direct Assessment protocols based on field (such as those above) by drawing on information from past R&D studies.

Tables 15 and 16 of the guidelines provide practical actions that can be taken to improve the identification of SCC sites. The report also provides guidance on estimation of re-inspection intervals for both high pH and near neutral SCC.

The guidelines provide limited advice on C-SCC however a reference provided indicates circumferential crack growth rates may be a factor of 100-1000 times faster than axial crack growth rates. This should be considered where high levels of pipe wall strain typically from movement could lead to C-SCC development.

5. APA SCC MANAGEMENT PROCESS

5.1. Introduction

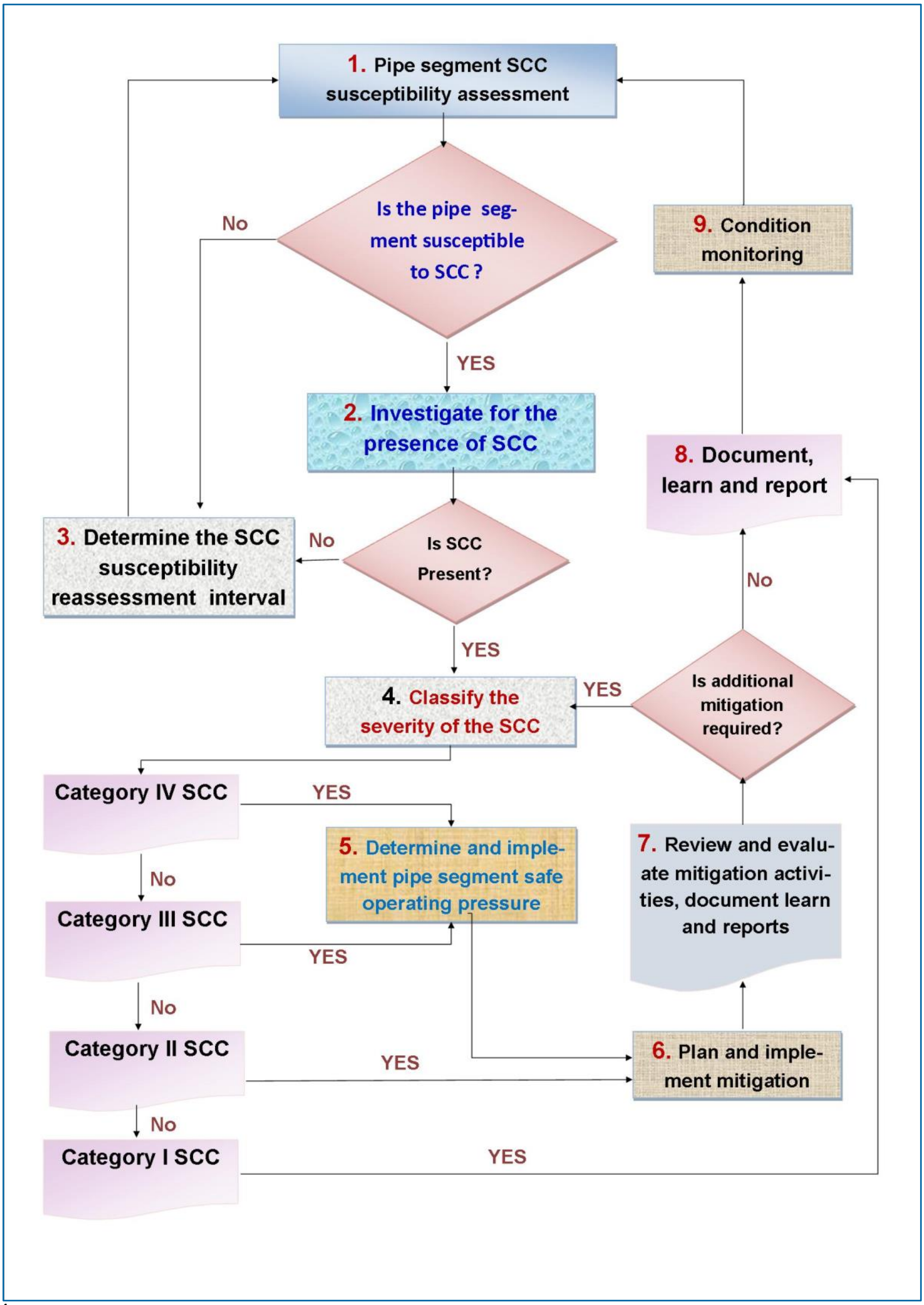
The APA SCC Management Process is based on APA's and the broader pipeline industries current understanding of SCC and factors that may influence SCC occurrence and severity. It draws heavily on the CEPA recommended practices.

An essential component of the process is the requirement for continuing monitoring of pipelines determined to be susceptible to SCC, as well as mitigation for those pipelines found to have SCC that could potentially impact the pipeline integrity.

5.2. SCC Management

The CEPA SCC management process is as shown in Figure 6.1 below and the following sections detail how this process is to be applied in practice to APA pipelines.

The schedule of proposed activities to be undertaken in accordance with this guide is to be documented in the PIMP.



[4]

Figure 6.1 - CEPA SCC Management Process

[4] Note: - SCC Categories are defined in section 5.2.5

5.2.1 Initial Assessment of SCC Susceptibility

Based on Australian and international experience all APA Transmission pipelines are to be considered for their susceptibility to SCC regardless of age or coating type. Where susceptibility is moderate or higher consideration shall be give to condition monitoring over the life of the asset.

An initial risk assessment to determine the relative SCC susceptibility is required for every pipeline segment in order to prioritise and identify pipeline segments for further investigation.

At minimum pipelines shall be segmented by scraper station sections and by:

- Coating Type and condition
- Pipeline Age
- Changes in MAOP.
- Heavy wall pipe sections (other than special crossings)
- Sections subject to higher pressure cycling
- Valve sections immediately downstream of compressor stations.
- Pipe-wall temperature
- SCC history

The assessment shall consider the relative susceptibility of the segments to:

- High pH SCC
- Near-Neutral SCC
- Circumferential Near-Neutral SCC

Records to be reviewed in the initial assessment include:

- Coating type and condition
- Pipeline attributes (age and season of construction, manufacturer, diameter, long-seam type. grade, pipeline alignment and stress concentrators)
- Operating conditions (stress level, pressure cycling, temperature)
- Environmental conditions (terrain, soil and soil drainage types, drainage pattern)
- Cathodic Protection records and Leak Survey reports.
- Previous detection of SCC on the pipeline segment or other similar pipeline segments.

Additional factors to be reviewed (where available) in accordance with the PRCI Final Report PR-377-063528 are:

For high pH SCC:

- Material-related - Cyclic stress-strain properties on material from cut-outs, hot taps or stockpiled pipe.
- Environment-related - Na/K content of groundwater by sampling or from local agricultural or environmental sources, Sample coating during excavations and determine coating porosity and/or impedance, Estimate soil CO_2 generation rates based on temperature and soil moisture content

For Near-Neutral SCC:

- Material-related - Sulphur content of steel from mill reports or material from cut outs, hot taps or stockpiled pipe.

- Environment-related - Sample coating during excavations and determine whether it is CP permeable or shielding, Identify sites with high soil resistivity, Identify sites where conditions change seasonally or due to transitions in soil properties.
- Stress-related - Identify location of stress raisers, Characterise stress concentration at long seam weld based on shape of weld crown, Determine residual stress distribution on cut outs.

Additional factors to be reviewed (where available) for C-SCC in accordance with the CEPA recommended practice are:

- Dents resulting from differential settlement at rocks or pipe wrinkles.
- Topography -Topographical regions characterised as uplands of undulating and rolling topography with high annual levels of precipitation and slopes of 10 degrees or greater
- Soil – Type and drainage
- Geotechnical data to assess susceptibility for differential settlement on slopes
- Pipe displacement data to assess and axial loads or bending moments on the pipe
- Depth of cover
- Historical records of soil movement

Operating stress is not considered to be a factor for C-SCC as the axial tensile stress associated with unusual loads or dents is the driving factor.

In order to improve the susceptibility assessment additional works programs may be required to obtain relevant information where this is not available. This may include:

- Stress strain cyclic testing and sulphur content analysis of pipe samples with known provenance.
- Installation of soil movement monitors or strain gauges at high risk locations.
- Soil sampling and testing.
- Capturing and monitoring pressure cycles.

5.2.2 Investigation of SCC Susceptible Segments and Ongoing Condition Monitoring

Methods available for investigation and condition monitoring of pipeline segments determined to be susceptible to SCC are:

- In line inspection (ILI) correlation excavations
- SCC Direct Assessment (SCCDA)
- Opportunistic Inspections
- Hydrotest

Hydro testing and ILI techniques are considered to be appropriate inspection techniques whereas SCCDA and opportunistic inspections are indicative sampling methods only. Although hydro testing can provide information regarding the maximum severity of damage to the pipeline it cannot identify the extent or location of all damage in a tested section, nor the extent of subcritical damage.

ILI provides a measure of extent, severity and location of the damage over the whole inspection length allowing comprehensive fitness for purpose (FFP) assessment to be undertaken. It does have a high stated probability of detection (POD) under normal operating conditions however there is no easy way to confirm the levels of false negatives.

SCCDA methods can have a very high probability of detecting shallow SCC, which generally occurs with a high frequency in pipelines that have SCC. However, this method has a low probability of detecting any possible injurious SCC that may exist.

SCCDA, particularly when targeted by strain assessment from IMU inspection, is the only proven[5] method available for detecting C-SCC.

Opportunistic excavations, such as corrosion and dent validations, coating defect repair programs and other maintenance activities have a much lower probability of detecting SCC however they provide useful information for refining SCCDA models.

In order to provide necessary supporting data any excavations on APA pipelines where coating damage is present or suspected shall be subject to 100% inspection for SCC using magnetic particle inspection or phased array eddy current techniques.

The most prevalent failure method of circumferential SCC is by leak. Routine leak surveys shall be considered during risk assessments for condition monitoring and risk mitigation at susceptible locations.

Minimum requirements for SCC investigation and ongoing condition monitoring to be specified in the PIMP are specified in Table 5.1 below.

Table 5.1: Minimum Level of Condition Monitoring for Pipeline Segments

Coating Type	Age <10yrs	Age >10yrs	Confirmed SCC on Segment above Category I**	Compressor <30km	Compressor >30km	Class Location R1/R2	Class Location T1/T2/S/I/HI
Coal Tar/Asphalt	OI	OI/DA***	SCC IMP	OI/DA***	OI	OI	OI/DA****
Tape Wrap	OI	OI/DA***	SCC IMP	OI/DA***	OI	OI	OI/DA****
Extruded PE	OI	OI	SCC IMP	OI/DA***	OI	OI	OI/DA*
Tri-Laminate	OI	OI	SCC IMP	OI	OI	OI	OI
FBE	OI	OI	SCC IMP	OI	OI	OI	OI
Liquid Epoxy	OI	OI	SCC IMP	OI	OI	OI	OI
Other	OI	OI/DA*	SCC IMP	OI/DA*	OI	OI	OI/DA*

OI: Opportunistic Inspections

DA: Dedicated SCC Direct Assessment Program

SCC IMP: Dedicated Management Plan to be developed in addition to PIMP

*: OI or DA based on condition of coating/joint coating

**: See Section 5.2.4 for SCC severity classification

*** OI acceptable if SCC risk assessed as low or negligible and is not in a high consequence area

**** OI acceptable if SCC risk assessed as low or negligible and MAOP<30% SMYS

[5] EMAT tools are available for detecting C-SCC however performance capabilities are not known.

Where SCCDA programs are implemented the number of excavations undertaken in the program shall be sufficient to produce statistically valid data. Direct assessment shall be undertaken in accordance with the practices and procedures outlined NACE RP0204:2004.

Where the presence of SCC is confirmed on any pipeline segment a dedicated SCC integrity management plan is to be developed for the entire pipeline. This plan shall consider level of risk to the public, personnel and supply and shall include one or more of the following programs to be implemented:

SCC DA programs of sufficient magnitude sufficient to establish the extent and likely severity of SCC on the pipeline.

- In line inspection (ILI) with dedicated crack detection tools.
- Coating refurbishment programs.
- Hydrotest.
- Pipe replacement.

5.2.3 SCC In Line Inspection

There are two types of crack detection ILI tools commercially available and proven to be capable of detecting sub critical axial cracking. Both technologies, EMAT and Ultrasonic (UT), require validation programs to determine their detection capabilities and their applicability for condition monitoring and/or mitigation of SCC. Commercially available EMAT tools are also available configured to detect circumferential cracking.

UT tools

UT ILI tools currently offer better detection and discrimination capabilities than EMAT tools; however they require introduction of a liquid slug into natural gas pipelines, making inspection runs complex, costly and disruptive. Experience with ultrasonic inspections on the NSW Moomba-Wilton pipeline has shown a high incidence of failed inspection runs due to gas ingress in the liquid slug.

Small diameter ultrasonic ILI tools are currently commercially available from several vendors but at this stage are not considered to be suitable for condition monitoring purposes due to the requirement of introducing a liquid slug into the pipeline and the associated issues with water/liquids management.

EMAT tools

EMAT ILI technology is newer than UT and discrimination and detection capabilities have improved to the extent where they are now viable condition monitoring tools, and may be acceptable for mitigation where detection capabilities are proven by validation. EMAT tools are not currently commercially available in sizes below DN300. Some EMAT tools also offer the ability to detect coating disbondment.

In line inspection with EMAT crack detection tools is not possible at present for pipelines below DN300 or where gas velocities do not allow for acceptable tool speed.

MFL tools

MFL tools of varying configurations, but particularly circumferential flux tools, may in some circumstances detect cracking where cracks are sufficiently open to disrupt the magnetic field. They are not considered by APA as suitable for condition monitoring or mitigation of SCC under most circumstances; however information obtained can be utilised to refine SCC susceptibility assessments.

It is anticipated that improvements in MFL tools and analysis may increase the capability to detect NN SCC cracks reliably however high pH SCC will most likely require UT style tools where grain boundary reflections indicate the presence of a crack.

APA Recommended Practice

Where practicable in line inspection with dry EMAT inspection technology followed by verification excavations is the APA preferred methodology of investigation of pipeline sections with confirmed or potentially at high risk of SCC as it:

- Provides information on the location, extent and severity of axial cracking.
- Has minimal or no impact on customer supply and gas quality.
- Has low environmental impact
- Is more effective in locating SCC that threatens the pipeline integrity than SCCDA.
- Provides information on coating condition (disbondment)

5.2.4 Determination of Re-Inspection Interval

Re-inspection intervals for all condition monitoring activities are to be determined by engineering risk assessment based on previous findings. The assessment shall consider the possibility that existing risk factors may change over time, the probability of detection of the method used and the consequences of failure in the pipeline segment. Where pipeline segments are determined to be susceptible to SCC a maximum re-inspection interval of 10 years shall be applied.

Re-inspection intervals where ILI is utilised for monitoring shall be determined based on initial ILI findings, tool detection capabilities and SCC growth rate assessments.

5.2.5 Classification of SCC Severity and Safe Operating Pressure Determination.

Axial SCC detected APA pipelines shall be classified using the CEPA criteria below using the following safety factors:

- 1.25 for pipeline segments in areas classified as R1 or R2 according to AS2885.1.
- 1.39 for pipeline segments in high consequence areas (AS2885.1 T1, T2, S, I or HI land classification).
- As determined by engineering assessment for pipeline segments subject to external loadings.

Failure pressures are to be determined using the methods outlined in Section 6.2.

Category		Definition	Description
I	$SCC_{\text{failure pressure}} \geq$ 110% x MOP x SF	A failure pressure greater or equal to 110% of the product of the MOP and Pipeline Safety Factor (typically is 110% of SMYS)	SCC in this category does not reduce pipe pressure containing properties relative to the nominal pipe properties; toughness-dependent failures are not expected in the category.
II	110% x MOP x SF > $SCC_{\text{failure pressure}} \geq$ MOP x SF	A failure pressure less than 110% of the product of the MOP and pipeline Safety Factor, but greater than or equal to the product of the MOP and Safety Factor (Failure pressure typically 100% SMYS)	No reduction in the pipe segment safety factor
III	MOP x SF > $SCC_{\text{failure pressure}} \geq$ MOP	A failure pressure less than the product of the MOP and pipeline Safety Factor but greater than the MOP	A reduction in the pipe segment safety factor
IV	MOP > $SCC_{\text{failure pressure}}$	A failure pressure equal to or less than the MOP (or >80% wall thickness)	An in-service failure becomes imminent as MOP is approached

MOP = Maximum Operating Pressure

SF = Safety Factor

Note: In determining the correct classification, failure pressures shall be determined on the basis of minimum pipe grade, toughness and wall thickness present in the pipeline segment where the SCC was discovered, not the actual pipe properties where the SCC was identified.

In general, category I and II are considered not critical. SCC in category I is not considered an immediate threat, but shall be documented where detected and the risk assessment/susceptibility model reviewed and the condition of the pipeline segment shall continue to be monitored.

In addition to the requirements for category I SCC, detection of category II features requires review of the pipeline segment MOP, development of a pipeline specific SCC integrity management plan and an engineering assessment to:

- Determine a maximum SCC growth rate.
- SCC growth mechanism and/or critical factors affecting growth.
- Review commonalities in cracking detected to improve future detection.
- Determine the appropriate timeline for implementation of mitigation.

Mitigation of the affected segment should be commenced within 4 years or the timeline determined by the engineering assessment and shall include at least one of the mitigation methods in Section 5.2.6.

In addition where category II features are detected by SCCDA further and more extensive investigations shall be undertaken based upon the same threat assessment criteria to determine if category III or IV features exist.

In addition to the requirements for category I and II SCC, where category III or IV features are discovered an immediate MOP restriction will be imposed, determined by the maximum monitored pressure observed over the preceding 60 day (Category III) or 15 day period (Category IV) divided by a safety factor of not less than 1.25. Appropriate SCC mitigation activities shall be undertaken within 2 years (category III) or 90 days (category IV) or within the timeline determined by engineering assessment.

In all cases where mitigation cannot be completed within the timeframe determined by the engineering assessment MOP restrictions shall be imposed.

All circumferential SCC shall be classified as severe damage unless the source of the axial tensile stress can be removed. Safe operating pressure and repair requirements shall be determined on a case by case basis where C-SCC is discovered.

5.2.6 SCC Mitigation and Repair

Available permanent SCC mitigation methods include:

- Hydrotest and repair of any failed defects.
- Reliable ILI and repair of SCC detected
- 100% Surface NDT for SCC, repair of any SCC detected and recoating.
- Pipe segment replacement.

The mitigation method/s utilised where required on APA pipelines will be determined by risk assessment. Mitigation and repair methods and their applicability are discussed in detail in Section 8.

MOP restrictions are not permanent mitigation options however may only be utilised to allow pipeline supply to continue until permanent mitigation measures can be applied.

5.2.7 Review, Reporting and Documentation

Risk assessments and pipeline MOP shall be reviewed on completion of any condition monitoring or mitigation programs or in the event of a pipeline failure.

Documentation shall be maintained in accordance with Section 9 of this guide.

6. SCC INTEGRITY ASSESSMENT

6.1. Introduction

Integrity Assessment is to be undertaken as information from condition monitoring and remediation programs becomes available:

Where category II or higher (more severe) SCC is reported by SCCDA a risk assessment shall be undertaken to determine the appropriate repair, control and mitigation strategy for the section. The risk assessment shall also consider implications of the findings to other segments of the affected pipeline and other similar pipelines and review monitoring/mitigation strategies for these assets.

Where long-term mitigation programs are identified as alternatives to repair (e.g. replacement or refurbishment) interim repairs or pressure restrictions shall be implemented to ensure risk control during and prior to completion of mitigation works.

6.2. Engineering Critical Assessment (ECA)

There are a number of techniques available for ECA to assess failure criteria for axial crack like defects in pipelines. These techniques predict the relationship between critical defect size and failure pressure. The best known most widely used method for pipelines is the NG-18 Ln-secant formula, other methods such as the pipe-Axial Flaw Failure Criterion (PAFFAC), CorLAS and API 579 are also available. Each of these methods has varying complexity and data requirements for materials properties.

ECA for integrity assessment of axially aligned SCC on APA pipelines detected by opportunistic inspections, SCCDA or ILI shall be undertaken utilising the following methods, or as determined by risk assessment and Approved:

- Level 1 Assessment: NG18 Ln-secant.
- Level 2 Assessment: CorLAS or API 579
- Level 3 Assessment: API 579 or finite element analysis.

ECA shall be undertaken utilising the following assumptions:

1. 1.25 safety factor on operating pressure (MAOP/MOP).
2. Length as interaction length as determined utilising the CEPA interaction rules for SCCDA or reported length by ILI vendor plus stated error.
3. Depth for SCCDA as peak depth or depth profile as determined by NDT for level 2 or 3 assessments. For ILI reported depth plus vendor stated error.
4. Materials as specified minimums or actuals as available from materials testing or mill certificates

ECA methods are in general not applicable to circumferential cracking as the axial tensile stress is usually unable to be reliably determined.

7. SCC MITIGATION AND REPAIR TECHNIQUES

Mitigation is a process intended to reduce risk through decreasing either probability of failure from identified threats, or consequences, or both. Various repair and mitigation options for SCC are discussed in literature summarised in table 7.1. Generally removal of the sharp crack like features is the primary aim of the repair process; ensuring uncontrolled failure is eliminated or controlled. However, APA also allows subcritical sharp features to remain in service where fatigue life can be demonstrated to exceed the remaining economic life of the asset.

Table 7.1 – Industry SCC Repair and Mitigation Options

ASME B31.8S	PRCI Pipeline Repair Manual	CEPA SCC Recommended Practice
• Pressure Reduction • Replacement • Grind Repair/ECA • Pressurised Sleeve • Reinforcing sleeve	• Grinding • Deposited metal (+ Grinding & Inspection) • Reinforcing Sleeve • Pressurised Sleeve • Mechanical Bolt-on-Clamp • Hot Tapping	• Recoating • Hydrostatic Retesting • Replacement • Pressure Containing Sleeve • Reinforcing Sleeve (+Grinding) • Grinding

7.1. SCC Operational Mitigation

Numerous factors are known to contribute to pipeline SCC susceptibility including: coating condition and preparation method, soil environment, pipe metallurgy, operating stresses and fluctuations, temperature, and the effectiveness of cathodic protection.

For an existing asset changing most of these parameters is not practicable, therefore operational mitigation on pipelines is therefore limited to the following:

1. Cathodic protection potential maintained to or above the industry standard -0.85V to a maximum of -1.2V.
2. Reduction in pipe wall temperature by installation of gas coolers on supply inlet and at all compressor stations.
3. Operational practices to minimise pressure cycles and operating pressure, wherever practicable.

7.1.1 Pressure Reduction

Pressure reduction may theoretically be used to lower the pipe wall stress thereby potentially reducing the growth rate to a negligible level or below the threshold for further crack initiation. In practice it is typically not feasible to lower pipeline pressures to the extent necessary to achieve these objectives whilst maintaining commercial supply, and localised stress factors may contribute to thresholds being exceeded.

Pressure reduction is not a long term solution, but can be used to decrease the likelihood of an immediate or near term SCC failure while a long term pipeline integrity management plan is determined.

Pressure reduction has negligible effect in reducing growth and preventing initiation of circumferential SCC.

7.2. SCC Repair Techniques

7.2.1 Grind Repair/ECA

BS31.8S, the PRCI Pipeline Repair Manual, CSA Z662 and AS2885.3 allow grinding removal of pipe wall defects as a permanent repair within allowable limits.

AS2885.3 allows up to 10% of wall thickness may be removed by grinding without subsequent assessment. Grinding shall be used in combination with non-destructive testing to ensure complete removal of the defect. Subsequent to grinding the pipe must be recoated.

Should complete removal of the defect require grinding in excess of 10%, an ECA shall be undertaken in accordance with AS2885.3 to determine if additional support is required, such as application of a reinforcing sleeve.

Grind repair is not applicable for circumferential SCC unless the source of the axial tensile stress can be removed.

7.2.2 Repair Sleeves

Repair sleeves are able to permanently restore the serviceability of the pipe. Only full encirclement sleeves are used for repair of SCC. The main types of full encirclement sleeve considered to have an SCC application are:

1. Pressure Containing (Type B)
   Pressure containing sleeves are designed to contain pressure and may be installed to repair leaks as they effectively transfer the hoop stress to the sleeve removing a key SCC driver. Pressure containing sleeves applied to SCC without prior removal by grinding shall be pressurised by hot tapping the pipeline. Fully welded pressure containing sleeves, subject to engineering stress analysis, are the only suitable repair sleeve for repair of circumferential SCC.
2. Composite Reinforced

   Composite reinforcing sleeves can provide a level of stress relief but are only approved for pipe wall reinforcement when stress corrosion cracks have been removed by grinding as a permanent repair to the metal-loss area.
3. Compression Sleeves
   Compression sleeves induce a compressive stress into the carrier pipe to prevent future crack growth. Compression sleeves are designed for part through wall defects and do not require removal of SCC by grinding. NSW experience has shown that they can be safely applied to leaking defects providing a gas tight repair and can be considered a permanent repair.

Note:

1. Reinforcing sleeves of any type are not applicable for circumferential SCC unless the axial tensile stress is removed
2. Leaks identified on pipelines need to be assessed on a case-by-case basis and repaired/removed subject to the results of ECA and Risk Assessment.

7.2.3 Recoating

Recoating pipeline can stop further SCC growth or initiation. During recoating any remaining mill scale can be removed by surface preparation prior to recoat. Grit blasting conducted during surface preparation also increases resistance to SCC by imparting a compressive residual stress on the pipe surface.

Coatings selected for recoating must resist cathodic disbondment, adhere well to the pipe, resist mechanical damage, not shield cathodic protection and be compatible with the existing coating. Recoating must be undertaken in accordance with an approved Procedure.

Recoating of SCC is a viable repair method for subcritical cracking without grinding removal where fatigue life can be demonstrated to exceed the remaining economic life of the asset. It is considered a permanent repair; however sample confirmation should be carried out every 10 years.

7.2.4 Hydrostatic Testing

Hydrostatic testing is used to locate cracks of a critical size at a specified test pressure. When properly implemented hydro testing assures that critical defects are destructively removed from the pipeline section under test. However, pressure testing does not provide information on the presence or severity of defects that survive the hydro test.

Hydro testing can blunt cracks but remaining sub critical cracks also may continue to grow by a combination of SCC, fatigue and corrosion fatigue. Therefore, hydrostatic retesting must be periodically performed on a pipeline containing growing defects to ensure pipeline integrity.

Where hydro testing is identified by risk assessment as a suitable condition monitoring, proof testing or SCC mitigation technique a hydro-test procedure shall be developed and approved for each test. Hydro-testing will be undertaken in accordance with ASME B31.8S in conjunction with the requirements of AS2885.5 as appropriate.

Hydro testing initiated as a result of pipeline failure shall be to a minimum spike test pressure of 100% SMYS of the nominal pipe wall with leak test pressure of 1.25 MAOP/MOP. The hydro test section shall be defined by risk assessment.

Where hydro testing is utilised to obtain a 12 month integrity window as an alternate integrity management procedure to repair (e.g. during looping or installation of pressure regulation) the spike test pressure for Hydro testing shall be 1.25x MAOP/MOP minimum.

Where hydro testing is utilised for integrity assessment or SCC mitigation purposes the retest period shall be determined by risk assessment in conjunction with ASME B31.8S, Fessler and Baker [Refs 2, 3 & 5] with a maximum initial 5 year retesting interval. The retest interval will be dependent upon the safety factor applied during the hydro test and the assumed SCC growth rate.

7.2.5 Pipeline Replacement

Pipeline replacement is a permanent mitigation method provided high integrity modern coatings are utilised and construction practices are in accordance with AS2885.

8. SITE INSPECTION AND ASSESSMENT PRACTICES

SCC Site works including excavation, coating removal, backfill and restoration are to be undertaken in accordance with approved pipeline operating procedures. An appropriate pressure reduction shall be calculated on a case by case basis with consideration of pipeline properties, working conditions or stresses which are atypical.

Relevant data should be collected from all excavations on the pipeline system in order to refine SCC susceptibility models. This data includes site topography, soil conditions, coating and pipe condition and any SCC damage. Wherever coating damage or disbondment is present the pipeline shall be subject to 100% magnetic particle inspection (MPI).

SCC defect sentencing is to be undertaken in accordance with Sections 5.2 and 8.2 of this guide.

8.1. Non-Destructive Testing

Non-destructive testing of SCC shall only be undertaken by NATA Certified (or equivalent) NDT technicians to an SCC specific inspection procedure.

Crack lengths are to be visually assessed with assistance of black on white magnetic particle inspection (MPI) to allow a photographic record to be maintained. Crack depth profiling is undertaken by ultrasonic shear wave or phased array methods.

Due to the complex nature of SCC colonies ultrasonic inspection can produce variable results. Accurate sizing of individual cracks in a SCC colony can be achieved utilising proper procedures and appropriately qualified personnel.

8.2. Defect Sentencing

SCC Defect sentencing shall be undertaken by suitably qualified engineering personnel using the methods outlined in Section 6.2 of this plan.

Site assessment for axial defect sentencing utilises crack lengths determined in accordance with the following interaction criteria [Ref 1]. In applying these criteria adjoining cracks with less than 1mm separation, or overlapping cracks showing indications of coalescence are to be considered as single cracks, not multiple shorter cracks.

$$y \leq 0.14\frac{(l_1 + l_2)}{2} \quad \text{....[1]}$$

Circumferential crack interaction can occur if the distance between cracks is less than or equal to ***y***

$$x \leq 0.25\frac{(l_1 + l_2)}{2} \quad \text{....[2]}$$

Axial crack interaction can occur if the axial spacing between cracks is less than or equal to ***x***

9. DATA MANAGEMENT

Pipeline SCC integrity management data and documentation are maintained in accordance with AS2885.3 Section 10.3. The pipelines Records Management Plan shall identify the critical records to be maintained and monitored, where the records are stored, and records retention/disposal procedures.

10. RESEARCH

Energy Pipelines CRC (APIA) and PRCI are both active in SCC research. During 2014-15

The following research is being carried out.

PRCI

1. A project to review the safe grinding limits for SCC on a live pipeline. This project is designed to ensure that where grinding is carried out that safe limits are known. It is unlikely to change the strategy for the Moomba to Wilton Pipeline but may have application of other assets

2. A project to review the CEPA interaction rules to remove over-conservatism. It is known that the level of conservatism attached to the CEPA interaction rules generates unnecessary levels of interaction. The project is designed to modify the rules to better suit the physical strength that actually exists.

EP CRC

3. Review of the interaction rules with respect to angled cracking to ensure that they are appropriately conservative. This project looks at the complex nature of angled cracking bringing together several other previous projects. It is anticipated that it will merge its findings with the finding of the PRCI project (2) to generate a improved interaction guideline for angled cracking

4. Review of the role of mill scale and rust in the initiation of SCC. This project will experimentally determine the role of mill scale and rusted mill scale in the initiation and development of cracking. It is thought that the original hydrotest on assets with mill scale cracked the mill scale producing local corrosion environments between the mill scale and the pipe wall material. It is anticipated that an improved understanding of the local pipe wall circumstances may provide improved SCC susceptibility guidelines and improved management practices. In addition the impact of rust on the ends of factory blasted pipe will be investigated to determine whether poor filed preparation of pipe joints might enable SCC initiation in addition to metal-loss. It is hoped that this may identify pipelines with very low SCC susceptibility

11. REFERENCES

1. Stress Corrosion Cracking Recommended Practices, Canadian Energy Pipeline Association (CEPA), Second Edition December 2007.
2. Stress Corrosion Cracking Study – Final Report, Department of Transportation, Research and Special Programs Administration – Office of Pipeline Safety, Integrity Management Program Delivery Order DTRS56-02-D-70036, Michael Baker Jr, January 2005.
3. Stress Corrosion Cracking in High Pressure Pipelines, Dr R. R. Fessler, Biztek Consulting Inc, USA, March 2007.
4. ANSI/NACE RP0204:2004 Stress Corrosion Cracking (SCC) Direct Assessment Methodology, 2004, Nace International, USA.
5. ASME B31.8S:2004, Managing System Integrity of Gas Pipelines, The American Society of Mechanical Engineers, 2004.

12. ABBREVIATIONS AND DEFINITIONS

12.1. Abbreviations

API	American Petroleum Institute
APIA	Australian Pipeline Industry Association
AS	Australian Standard
ASME	American Society of Mechanical Engineers
BWMPI	Black on White magnetic Particle Inspection
CCL	Critical Crack Length
CDL	Critical Defect Length
CEPA	Canadian Energy Pipeline Association
CNV	Charpy V-notch
CP	Cathodic Protection
CSA	Canadian Standards Association
DA	Direct Assessment
DOP	Department of Planning
EAC	Environmentally Assisted Cracking
ECA	Engineering Critical Assessment
EPRG	European Pipeline Research Group
FBE	Fusion Bonded Epoxy
FFS	Fitness For Service
HCA	High Consequence Area
ILI	In-Line Inspection
ISO	International Standards Organisation
IMP	Integrity Management Plan
IMU	Inertial Measurement Unit (positioning data device for intelligent pigging)
MFL	Magnetic Flux Leakage
MAOP	Maximum Allowable Operating Pressure
MOP	Maximum Operating Pressure
MPI	Magnetic Particle Inspection
MSP	Moomba Sydney Pipeline Network
MW	Moomba to Wilton Pipeline

NACE	National Association of Corrosion Engineers
NDT	Non-Destructive Testing
POF	Probability of Failure
POR	Probability of Rupture
PRCI	Pipeline Research Council International
SAOP	Safety and Operating Plan
SCC	Stress Corrosion Cracking
SCCDA	Stress Corrosion Cracking Direct Assessment
SMYS	Specified Minimum Tensile Strength
USCD	Ultrasonic Crack Detection
US-DOT	United States Department of Transportation
UT	Ultrasonic Testing

12.2. Definitions

Colony – Refers to a grouping of stress corrosion cracks – typically stress corrosion cracks occur in groupings consisting of hundreds or thousands of cracks within a relatively confined area.

Crack Interaction - The action of two cracks acting as a single crack under load/stress which are physically separated as two individual entities.

Critical Defect Length (CDL) – The length of a through-wall axial flaw that, if exceeded, will grow rapidly and result in pipeline rupture. When the defect is smaller than this length the pipeline will only leak at failure. The CDL, or critical crack length (CCL), is a function of the operating stress.

Engineering Critical Assessment (ECA) – A documented assessment of the performance of a structure based on engineering principals and material properties.

Fatigue – The progressive cracking of a metal in response to conditions of repeated cyclic stress.

High Consequence Area (HCA) – Location where pipeline failure can be expected to result in multiple fatalities or significant environmental damage. For remote pipeline sections high consequence areas are limited to locations of public and operating personnel exposure such as road crossings, homesteads and valve sites.

High pH SCC – Pipeline SCC which is associated with an electrolyte which has a pH in the Alkaline range, specifically greater than pH 9.3 and in which cracking follows an intergranular path and is often branched.

In-Line Inspection – The inspection of a pipeline from the interior of the pipe using a tool which travels in the pipeline with the fluid being transported. The tool or vehicle, also known as a pig, uses non-destructive testing techniques to inspect the wall of a pipe from the inside as it travels through the pipeline. The pig may also carry an IMU unit to collect positioning data.

Limit State Criteria – In limit state assessment, individual limits are determined for each of a number of possible failure mechanisms. For pipelines, the usual limit states are fracture at a defect, plastic collapse at a defect, tensile yielding of a pipe body, and compressive buckling. A limit state criterion is the maximum stress, strain or load which can be applied prior to failure by a specific failing condition.

Near Neutral pH SCC – Pipeline SCC associated with an electrolyte which has a pH in the neutral range (pH 6-8); the reference to near neutral pH is used to differentiate if from the high pH SCC which is associated with more alkaline electrolyte. The cracking in this form is wide, non branching and follows a transgranular path through the pipe wall.

Pipeline Section – A section of the pipeline between scraper stations.

Pipeline Sector – A length of pipeline between compressor stations or pressure regulating stations with same MAOP or MOP control requirements.

Pipeline Segment – A length of pipeline with similar characteristics and risk factors for SCC.

Stress Corrosion Cracking – Cracking caused by the conjoint action of a corrosive environment in combination with tensile stress on a susceptible material.

Sub critical Crack – A crack that is not large enough to cause spontaneous failure at a given pressure or stress.

RISK EVALUATION & MANAGEMENT

Pipeline Licensee: APT Petroleum Pipelines Ltd   Live database safety mgt. study

Pipeline: 1 ***All pipelines***

Section: 2 ***Non-location-specific*** - -

THREAT DETAILS *(assuming no additional mitigation)*

ID ***220*** ***Dents combined with metal loss or located on welds*** KP

Location Non-location-specific   Construction defect

Existing design Dec 2014 - Known dents exist on DN250 pipeline some have metal loss or are located on welds based on ILI information from 2014.

2015 - ILI Information from last run on DN250 highlighted dents and digup program for 2016 includes approx. 70 dents with associated features. Ongoing management of these anomalies will be continued using field and ILI data. Fatigue being addressed through RLR, and takes defects

CONSEQUENCES *(assuming no additional mitigation)*

Failure mode pipeline leak or rupture on the DN250 pipeline
identified dents are not located in populated areas

Effects
1. leak with ignition and fire
2. rupture without ignition
3. rupture with ignition

Severity notes
1. severe (based on injuries requiring hospital treatment)
2. severe (based on supply restriction)
3. major (based on few fatalities)

Freq. notes
1. unlikely
2. remote
3. remote (low range)

Frequency Remote   **Severity** Major   **Rank** **INTERMEDIATE**

MITIGATION *(and revised risk evaluation & ranking)*

ID	Action	By	Due
139	Corrosion - complete MFL & calliper pigging of remaining 2 x DN250 sections		
140	Corrosion - implement risk based digup and repair program		
188	Integrity - implement MOP management system to effectively restrict MOP where required for integrity reasons such as metal loss or dent anomalies.	Francis Carroll	27 Jul 2016

New Frequency Hypothetical   **New Severity** Major   **New Rank** **Low**

RISK EVALUATION & MANAGEMENT

Pipeline Licensee: APT Petroleum Pipelines Ltd | Live database safety mgt. study

THREAT DETAILS *(assuming no additional mitigation)*

ID **42** ***External corrosion - Over Ditch Coated*** KP

Location Non-location-specific Corrosion

Existing design 2010 - Pipe coating (tape wrap on DN 250 & DN 300), cathodic protection, fortnightly CP monitoring, local DCVG surveys as required (eg. suspected damage or new developments), ILI frequency to be set based on previous ILI survey (APA In-line Inspection Policy), significant defects repaired as required. CP provides protection in accordance with AS2832. Can experience shielding under the coating and the ILI surveys will detect significant defects. Where new developments result in potential accessibility issues in future the pipeline is stripped, blasted

CONSEQUENCES *(assuming no additional mitigation)*

Failure mode 1) Most likely is pressure reduction and immediate repair.
2) Typical failure for corrosion defects with existing controls would be pinhole leak.

Effects 1) MAOP Reduction and Repair - Loss of supply consequence only
2) Pinhole leak - loss of supply, no ignition, rarely personnel on site

Severity notes 1) Minor
2) Minor

Freq. notes 1) Occasional
2) Unlikely

Frequency Occasional **Severity** Minor **Rank** **Low**

MITIGATION *(and revised risk evaluation & ranking)*

ID	Action	By	Due
119	Update CP survey procedure and the planned maintenance schedule so that all T1 and T2 areas are surveyed 6 monthly.	Nick Doblo	4 Mar 2015
188	Integrity - implement MOP management system to effectively restrict MOP where required for integrity reasons such as metal loss or dent anomalies.	Francis Carroll	27 Jul 2016

New Frequency **New Severity** **New Rank**

RISK EVALUATION & MANAGEMENT

Pipeline Licensee: APT Petroleum Pipelines Ltd — Live database safety mgt. study

THREAT DETAILS *(assuming no additional mitigation)*

ID ***43*** ***Internal corrosion*** — KP

Location Non-location-specific — Corrosion

Existing design 2010 - Clean dry sales gas, no internal corrosion detected through ILI.
2015 - Gas typically contains minimal water or corrosives, no significant internal corrosion found to date. Any internal features found through ILI will be included in future repairs. Cleaning pigging removes bulk liquid from pipeline. Liquid from Peat Lateral contains water and corrosives. Cleaning pigs assist in management.

CONSEQUENCES *(assuming no additional mitigation)*

Failure mode Internal corrosion defects not expected to grow to failure point undetected between ILI runs.

Effects

Severity notes

Freq. notes

Frequency **Severity** **Rank**

MITIGATION *(and revised risk evaluation & ranking)*

ID	Action	By	Due
144	Establish regular cleaning pigging on Peat Lateral and RBP affected sections for liquids removal.	Francis Carroll, Paul	

New Frequency **New Severity** **New Rank**

THREAT DETAILS *(assuming no additional mitigation)*

ID ***44*** ***Stray current corrosion (railway etc)*** — KP

Location Non-location-specific — Corrosion

Existing design 2010 -Not identified as an issue for these pipelines.
2015 - As above.

CONSEQUENCES *(assuming no additional mitigation)*

Failure mode

Effects

Severity notes

Freq. notes

Frequency **Severity** **Rank**

MITIGATION *(and revised risk evaluation & ranking)*

ID	Action	By	Due

New Frequency **New Severity** **New Rank**

RISK EVALUATION & MANAGEMENT

Pipeline Licensee: APT Petroleum Pipelines Ltd | Live database safety mgt. study

THREAT DETAILS *(assuming no additional mitigation)*

ID **45** ***Stress corrosion cracking - Axial*** KP

Location Non-location-specific Corrosion

Existing design 2010: Some direct inspection for SCC done downstream of Wallumbilla, none found. Standard procedure for every dig is to include check for SCC.

July 2014: Evidence of axial SCC was discovered during the repair of a loss of containment failure on the Toowoomba Range. The failure was a result of circumferential SCC and ground movement, however minor axial SCC was also found. This threat requires further evaluation

CONSEQUENCES *(assuming no additional mitigation)*

Failure mode Axial crack leading to leak or rupture of pipeline

Effects 1- Leak with or without ignition in low populated areas or leak in populated area without ignition
2- Leak with ignition in populated area
3- Rupture with or without ignition in low populated areas or rupture in populated area without ignition

Severity notes 1-minor (Supply on DN250)
2-severe (injuries requiring hospital treatment)
3- severe (Supply DN300 Metro)
4-Major (few fatalities + life threatening injuries)

Freq. notes 1-remote
2-remote
3-remote
4-hypothetical

Frequency Hypothetical **Severity** Catastrophic **Rank** **INTERMEDIATE**

MITIGATION *(and revised risk evaluation & ranking)*

ID	Action	By	Due
75	Toowoomba Range 2014 - Review stress analysis report and pigging data and site measurements from cutout of defect. Develop a management strategy	QLD Engineering	
98	Finalise SCC Management Plan and implement any associated actions.	Francis Carroll	4 Sep 2015
136	SCC Mitigation - Review wall thickness and location class to identify areas of thin wall DN250 in populated locations. Assess alternative options to mitigate	Michael Brown	30 Sep 2015
188	Integrity - implement MOP management system to effectively restrict MOP where required for integrity reasons such as metal loss or dent anomalies.	Francis Carroll	27 Jul 2016

New Frequency **New Severity** **New Rank**

RISK EVALUATION & MANAGEMENT

Pipeline Licensee: APT Petroleum Pipelines Ltd — Live database safety mgt. study

THREAT DETAILS *(assuming no additional mitigation)*

ID **72** ***Undetected metal loss*** KP

Location Non-location-specific — Corrosion

Existing design In-line inspection done, but all ILI tools have finite accuracy and probability of detection.
2014 - ILI detects all significant metal loss defects.
2015 - ILI frequency adequate to detect all significant metal loss, as per 2014.

CONSEQUENCES *(assuming no additional mitigation)*

Failure mode Regular pigging renders this threat non credible for failure.

Effects

Severity notes

Freq. notes

Frequency **Severity** **Rank**

MITIGATION *(and revised risk evaluation & ranking)*

ID	Action	By	Due
2	Undetected corrosion - consider study to evaluate likelihood and size of undetected metal loss that could remain in the pipe, and their consequences	Manager AM&E	

New Frequency **New Severity** **New Rank**

RISK EVALUATION & MANAGEMENT

Pipeline Licensee: APT Petroleum Pipelines Ltd | Live database safety mgt. study

THREAT DETAILS *(assuming no additional mitigation)*

ID ***73*** ***Undetected cracking*** KP

Location Non-location-specific | Corrosion

Existing design 2010: In-line inspection for cracking not done, and not likely to be practicable. Spot checks for external cracking at every dig.

2014: Following a loss of containment failure in the DN250 pipeline on the Toowoomba Range, due to circumferential cracking, a number of actions have been added to the SMS including development of an SCC management plan

CONSEQUENCES *(assuming no additional mitigation)*

Failure mode Undetected cracking of welds, SCC etc could feasibly fail before first ILI run or hydrotest or other means to detect.

Effects
1) Rupture due to CDL-length crack undetected, populated
2) Rupture with ignition, populated
3) Leak, populated
4) Leak with ignition, populated

Severity notes
1) DN250 Severe, DN400 Major
2) DN250 Catastrophic, DN400 Catastrophic due to fatalities in populated area.
3) DN250 Minor, DN400 Severe
4) DN250 Major DN400 Major

Freq. notes
1) DN250 Remote, DN400 Hypothetical
2) DN250 Hypothetical, DN400 Hypothetical
3) DN250 Remote DN400 Hypothetical
4) DN250 Hypothetical DN400 Hypothetical

Frequency Hypothetical **Severity** Catastrophic **Rank** **INTERMEDIATE**

MITIGATION *(and revised risk evaluation & ranking)*

ID	Action	By	Due
58	Undetected cracking - consider study to evaluate likelihood and size of undetected cracks that could remain in the pipe, and their consequences	Manager AM&E	
98	Finalise SCC Management Plan and implement any associated actions.	Francis Carroll	4 Sep 2015

New Frequency **New Severity** **New Rank**

RISK EVALUATION & MANAGEMENT

Pipeline Licensee: APT Petroleum Pipelines Ltd — Live database safety mgt. study

THREAT DETAILS *(assuming no additional mitigation)*

ID ***218*** ***Circumferential cracking in DN250 and DN300 pipelines (1969) due to strain on pipe*** KP

Location Non-location-specific — Corrosion

Existing design December 2014 - DN250 pipeline known to be susceptible to circumferential SCC, known failures have occurred on the Toowoomba Range, and the Bremer River. Cut out repairs have been completed at Zimms corner. In 2014 multiple stain event have been excavated and inspected (7 sites) so far no cracking has been detected at strain level below 0.3
Other known strain events exist (approx 21 >0.2% strain) in 5 x DN250 sections + DN300 Metro.
Two DN250 sections are yet to be pigged (Yuleba to Condamine & Gatton to Bellbird)

CONSEQUENCES *(assuming no additional mitigation)*

Failure mode Circumferential SCC leading the leak or rupture

Effects 1- Leak with or without ignition in low populated areas or leak in populated area without ignition
2- Leak with ignition in populated area
3- Rupture with or without ignition in low populated areas or rupture in populated area without ignition

Severity notes 1-minor (Supply on DN250)
2-severe (injuries requiring hospital treatment)
3- severe (Supply DN300 Metro)
4-Major (few fatalities + life threatening injuries)

Freq. notes 1-occasional
2-unlikely
3-remote
4-hypothetical

Frequency Hypothetical **Severity** Catastrophic **Rank** **INTERMEDIATE**

MITIGATION *(and revised risk evaluation & ranking)*

ID	Action	By	Due
137	SCC Circumferential - complete digup and MPI inspections of critical identified strain events as per the management plan		
138	SCC Circumferential - complete XYZ pigging and strain analysis of remaining 2 x DN250 sections		
98	Finalise SCC Management Plan and implement any associated actions.	Francis Carroll	4 Sep 2015

New Frequency Remote **New Severity** Severe **New Rank** **Low**

RISK EVALUATION & MANAGEMENT

Pipeline Licensee: APT Petroleum Pipelines Ltd — Live database safety mgt. study

THREAT DETAILS *(assuming no additional mitigation)*

ID ***219*** ***External metal loss / corrosion*** KP

Location Non-location-specific — Corrosion

Existing design December 2014 - Known metal loss throughout DN250 pipeline lowest safety factor of 1.28
(2 x DN250 section not pigged since 2008 planned for 2015)

2015 - DN250 all sections pigged, severe metal loss excavated and repaired, further repairs due 2016.

CONSEQUENCES *(assuming no additional mitigation)*

Failure mode Corrosion continues through wall leading to leak or rupture.
Known worst case is in non populated area.

Effects 1. pin hole leak
2. pipeline rupture

Severity notes 1. minor
2. severe

Freq. notes 1. remote
2. remote

Frequency Remote **Severity** Severe **Rank** **Low**

MITIGATION *(and revised risk evaluation & ranking)*

ID	Action	By	Due
139	Corrosion - complete MFL & calliper pigging of remaining 2 x DN250 sections		
140	Corrosion - implement risk based digup and repair program		

New Frequency **New Severity** **New Rank**

APA Group

Procurement Policy

Owner	General Manager Infrastructure Procurement		
Policy Approved by Managing Director			Date 5/8/15
Direct questions on Policy to	General Manager Infrastructure Procurement		
Policy to be reviewed no later than	August 2018		
Version control	Date	Version	Nature of Change
	30 June 09	Policy	Approved by MD
	August 2015	1.0	Major redraft of '*Use of Purchase Orders Policy*' and '*Procurement Policy*' (was '*General Procurement* Policy').

Contents

1 Purpose

To ensure rigour in APA's procurement practices and to mitigate risks connected with the procurement of goods and services by APA.

2 Coverage / scope

This policy applies to all employees and contractors acting for or on behalf of APA Group and its wholly owned subsidiaries.

APA's procurement procedures and the respective responsibilities of APA Procurement and the APA business unit are set out in the *Procurement Guide*.

In this policy:

- "Supplier" means a supplier, contractor, vendor or consultant that may provide or provides goods and/or services to APA;
- "PO" means APA Oracle Purchase Order and "WO" means APA Maximo Work Order; and
- "Procurement Agreement" means any agreement, contract, deed, lease or other document (eg a letter) other than a PO or WO that is used to procure goods and/or services and a variation, assignment or novation of any such document.

Please refer any queries to the General Manager Infrastructure Procurement who is the owner of this policy and the *Procurement Guide*.

3 Values & commitments

APA is committed to providing value to its unit holders and recognises that effective and efficient procurement practices are essential to facilitate optimal sustainable outcomes for APA.

APA employees must act in an ethical, transparent and independent manner at all times when involved in a procurement process. The procurement process probity requirements and guidelines for dealing with Suppliers are set out in the *Procurement Guide*.

APA's procurement practices are designed to ensure:

- financial, commercial, legal, operational, reputational, regulatory, environmental and occupational health and safety risks are determined, monitored, managed and reduced;
- goods and/or services meet specification and are delivered on-time at competitive prices from financially stable Suppliers;
- best value for money is realised, as evaluated on a total cost of ownership basis; and
- effective procurement processes and procedures, including rigorous ongoing contract management and Supplier relationship management are applied consistently.

4 Policy

4.1 Making a financial commitment to a Supplier

APA employees in the relevant business area with the appropriate category and delegation of authority as set out in the *Table of Delegated Limits of Authority* are the only APA representatives authorised to approve a commitment to a Supplier.

When determining the authority level required against the delegated limits of authority, the total cumulative procurement value of the commitment is applicable. Dividing a commitment to a Supplier into two or more parts to evade a delegated limit of authority is a violation of the *Delegations of Authority* and is not permitted.

Only in certain circumstances as set out in the *Delegations of Authority*, may authority be delegated to Suppliers acting on behalf of APA.

4.2 Paying a Supplier

APA's policy is to pay its Suppliers on-time in accordance with the contractual commitments agreed with a Supplier.

As set out in the *Establishment of Supplier Credit Accounts & Standard Payment Terms Policy* APA's standard payment terms for procurement of goods and/or services are thirty (30) calendar days from the end of the month in which a tax invoice is received or dated, whichever is later.

4.3 Method of purchase

To mitigate risks inherent in purchasing transactions, APA mandates the use of a formal contract approved under the relevant delegation of authority as set out in the *Table of Delegated Limits of Authority*. This requirement does not apply to purchases which fall within the scope of the exemptions contained in the *Corporate Credit Card Policy*.

This policy sets out the circumstances where the formal contract may take the form of a PO or WO and where a Procurement Agreement must be used (in conjunction with a PO or WO).

4.4 Using a corporate credit card

Corporate credit cards are to be used and acquitted in accordance with the *Corporate Credit Card Policy*.

Corporate credit cards should only be used for business expenditure by authorised APA employees for low value, low risk goods and services (particularly travel, entertainment, professional development and education related expenses). Otherwise, purchases of goods and/or services for APA operations are to be by issuance of a PO or WO wherever possible. In the case of an urgent operational requirement a corporate credit card may be used for a once-off or incidental purchase where the transaction value is less than AUD$500 and where a preferred Supplier does not service that location.

4.5 Using a PO or WO

A PO or WO is to be used in accordance with the *Use of Purchase Orders Policy*.

POs and WOs are used to make purchasing transactions at APA more efficient and accountable however they do not effectively mitigate the risks inherent in all purchasing transactions. The circumstances where a Procurement Agreement is required are set out in section 4.6.

4.6 Using a Procurement Agreement

A Procurement Agreement is required if certain criteria are present in the procurement of goods and/or services. If any of the criteria listed in the *Use of Procurement Agreement Checklist* are present, a PO or WO must not be issued without the prior approval of the relevant Procurement Manager (refer *Goods and Services Quick Reference Guide*).

A Procurement Agreement must be executed in conjunction with issuing a PO(s) or WO(s) that references the overarching Procurement Agreement. The terms and conditions of the PO or WO are overridden by the terms and conditions of the relevant overarching Procurement Agreement.

4.7 Types of Procurement Agreements

A Procurement Agreement may be the applicable:

- APA Precedent Procurement Agreement;
- bespoke APA Procurement Agreement; or
- Supplier’s own form of Procurement Agreement.

APA’s preferred position is to use the relevant APA Precedent Procurement Agreement and it must be considered prior to considering an alternate form of agreement. A suite of APA Precedent Procurement Agreements is housed in the *Legal Document Library* and maintained and kept current by APA Legal. An APA Precedent Procurement Agreement must be sourced directly from the *Legal Document Library* as past versions may not reflect current legislation and/or current APA policy.

4.8 Using the correct APA Group legal entity

APA’s default contracting entity for a Procurement Agreement is APT Management Services Pty Limited (ABN 58 091 668 110). However, in some instances the relevant APA contracting entity is the entity that owns the asset or the entity that provides the goods and/or service to which the Procurement Agreement directly relates. Refer to APA Legal for clarification.

For tax purposes each operating unit contains a contracting entity that represents the group of APA entities to which it belongs. The APA Finance System determines the correct default tax contracting entity based on the relevant operating unit, eg APA, EII, GGT, etc.

4.9 Sourcing goods and/or services

The Procurement Manager or their delegate will work with the APA business unit to ensure alignment of the documentation of the business unit's requirements with the Procurement Agreement. The APA business unit that requires goods and/or services must provide the detailed requirements including specification, quantity, location, timing, service levels, etc. This includes obtaining relevant inputs from subject matter expert business units (eg, HSE, Infrastructure Strategy & Engineering, Group IT, Regulatory, etc).

The following requirements must be met when sourcing goods and/or services:

- seek acceptance of APA's terms and conditions (PO or WO and Procurement Agreement) by the Supplier at the initiation of the discussions and prior to any commitment being made by APA;
- conduct risk assessments commensurate with the likely risks for:
    - Health Safety and Environment (HSE), quality, operational, technical, regulatory, delivery and other relevant risks; and
    - commercial risk incorporating an objective evaluation of Supplier's documented offers and presentations including the relevant Procurement Agreement and any proposed variations; and
- if the procurement value is or is likely to be greater than:
    - AUD$100,000 obtain competitive written quotes or proposals from a minimum of 3 relevant Suppliers; and
    - AUD$200,000 conduct a formal Request for Quote, Request for Proposal or Request for Tender as set out in the *Procurement Guide*.

An exception to any part of this requirement, including a requirement to dual or sole source goods and/or services, regardless of whether a Supplier is a member of an APA preferred Supplier panel, must be approved in writing by a *Delegation of Authority* of Level 3 or above and the relevant Procurement Manager (refer *Goods and Services Quick Reference Guide*).

Disaggregating requirements and splitting purchases either on credit card, POs, WOs or Procurement Agreements to avoid proper procurement processes is not permitted. A series of reasonably related purchases may be considered as a single transaction for the purpose of determining compliance with this policy.

4.10 HSE and sourcing goods and/or services

APA requires its Suppliers to have similar HSE standards and values to APA (refer *Health Safety and Environment (HSE) Policy*). Suppliers that provide goods and/or services to APA must have a system that complies with the relevant work, health, safety and environmental legislation and local site rules or with the APA Group HSE policies and procedures.

Prior to engagement by APA, Suppliers must be assessed based on their capabilities and competencies to perform work for and on behalf of APA, and to ensure their HSE performance is aligned with the standards set out in *Safeguard Management System Overview Elements*. Refer in particular to 'Element 10 - Contractors and Suppliers'.

4.11 Managing Suppliers

The requirement to properly manage and interact with Suppliers exists regardless of whether it is part of a procurement or contract management process and must be performed at all times in a manner consistent with the overall business objectives of APA.

The principles and responsibilities for contract management and relationship management with Suppliers are outlined in the *Procurement Guide*.

4.12 Material Service Providers

Australian Pipeline Limited is a licensee of an Australian Finance Services Licence under the Corporations Act 2001. As a licensee APA's obligations are set out in *Managing Material Service Providers* policy and may be summarised as follows.

APA must manage appropriately the selection, engagement, management, renewal and/or termination of a 'Material Service Provider'.

A 'Material Service Provider' is a Supplier that could severely impact APA security holder value, through the failure to provide the services contracted, including but not limited to:

- a service provider under an operating expense agreement (Opex or Capex) with a total value equal or greater than AUD$20,000,000 per annum; or
- a service provider of share registry services, legal services, statutory or company audit services.

4.13 Providing Supplier references

APA's preference is to provide verbal references only. A reference should be only be provided with the Supplier's knowledge and in relation to current or recent goods and/or services provided to APA and in relation to the Supplier's personnel at locations the reference provider is or has been personally involved with. The reference provider must not make statements that are derogatory or libellous or reveal any details of APA's commercial relationship with the Supplier.

An exception to any part of this requirement must be approved in writing by a Delegation of Authority Level 3 or above and the relevant Procurement Manager.

5 Breach of Policy

Breaches of this policy will be regarded as misconduct and may result in disciplinary action, which may include the termination of employment or contract as applicable. Any incident or breach will be properly investigated and the affected employee/s or contractor/s given an opportunity to respond.

6 Links / interaction with other policies/ procedures

Refer to APA intranet 'HUB':

Corporate Credit Card Policy
Delegations of Authority

Establishment of Supplier Credit Accounts and Standard Payment Terms Policy
Goods and Services Quick Reference Guide
Health Safety and Environment (HSE) Policy
Legal Document Library
Managing Material Service Providers
Procurement Guide
Risk Management Policy
Safeguard Management System Overview Elements
Table of Delegated Limits of Authority
Use of Purchase Orders Policy

7 Attachments

Use of Procurement Agreement Checklist

Use of Procurement Agreement Checklist

If any of the following criteria are present in the procurement of goods and/or services a Procurement Agreement is required and a PO or WO must not be issued without the prior approval of the relevant Procurement Manager (refer *Goods and Services Quick Reference Guide*).

Criteria	
ASSESSED RISK	A risk assessment conducted in accordance with the *Risk Management Policy* has identified a risk in relation to the procurement that is either moderate, high or extreme
CONFIDENTIALITY	The procurement requires the provision of APA confidential information
CURRENCY	The procurement is in a currency (in whole or in part) other than AUD$
CUSTOM MADE GOODS	Goods are not "off the shelf"
DELIVERY	Late delivery or provision of defective goods and/or services will expose APA to loss greater than the procurement value
PERSONAL PROPERTY SECURITIES ACT	The procurement involves APA-owned plant, property or equipment being in another party's custody or control or being located on a site not owned or leased by APA or for which APA does not have an easement, for longer than 9 months
INSURANCE	The procurement involves APA-owned plant, property or equipment of value greater than AUD$250,000 being in another party's custody or control or being located on a site not owned or leased by APA or for which APA does not have an easement
INTELLECTUAL PROPERTY	The procurement involves the use of APA or Supplier intellectual property (other than 'shrink wrap' software but including advice or patents, copyright, know how, trade secrets, rights in circuit layouts, registered designs, trademarks, service marks, trade names, design rights, database rights, business names)
LEASE or LICENCE	The procurement involves a lease or a licence (other than 'shrink wrap' software)
NON-STANDARD DOCUMENT	The procurement involves a PO, WO or Procurement Agreement that is not an APA Precedent Procurement Agreement or that is an amended APA Precedent Procurement Agreement (other than 'shrink wrap' software)
OVERSEAS SUPPLIER	The procurement is from a non-Australian resident Supplier (other than 'shrink wrap' software)
PREPAYMENT	The procurement involves payment prior to APA acceptance of goods and/or services
PRICE	The procurement value is greater than AUD$200,000
IF IN DOUBT ASK THE PROCUREMENT MANAGER	

This requirement does not apply where a PO or WO is raised under a current Procurement Agreement and where the PO or WO specifically references the overarching Procurement Agreement.

ISE Document

TECHNICAL POLICY

In-Line Inspection

Transmission Pressure Pipelines

Owner		M Fothergill		Next Review Date Feb 2020	
Document No		320-POL-AM-0022			
Rev #	Date	Status	Originated	Checked	Approved
0	Feb 2015	Initial	G Callar	M Brown	M Fothergill GM ISE

APA Group

REVISION RECORD

Revision No.	Description of Revision
A	Issued for Comments
0	Issued for Use:

TABLE OF CONTENTS

1 INTRODUCTION

This document is applicable to all transmission pressure steel pipelines operated by Transmission and Network personnel.

All work performed in accordance with this document shall comply with the all relevant Acts, Regulations, Standards, and Codes of Practice of all authorities having jurisdiction over the work.

When conflict exists between the various applicable documents, the following order shall apply, in decreasing order of precedence. Where APA requirements are more stringent, they shall take precedence.

- Acts of law or other legislation
- Government licenses and permits
- APA Standards
- Local standards

Any identified discrepancies shall be reported to the document owner for remedy.

If you are reading a hard copy of this document, please consider it uncontrolled.

1.1 Purpose and Scope

This policy is to provide standard criteria for determining the selection of appropriate inspection tools and inspection intervals using intelligent pigging inspection technology for every piggable pipeline with a nominal diameter greater than 100mm. either owned or operated by APA.

1.2 Definitions

The definitions used in this document are listed in Table 1;

Table 1 Definitions

Item	Definition
Transmission Pressure	Pipelines operating under AS2885.3 at >20% SMYS

1.3 Abbreviations

The abbreviations used in this document are listed in Table 2; when the table is more than one page it should be included as an Appendix.

Table 2 Abbreviations

Item	Definition
ILI	Inline Inspection also known as Intelligent Pigging

1.4 References

All work performed in accordance with this Document Type shall be in conformance with the current issue, including amendments, of those national and international standards, codes of practice, guidelines and APA documents listed in Table 3; When the table is more than one page it should be included as an Appendix.

Table 3 Referenced Documents

Referenced Document	
AS2885.3	Pipelines – Gas and Liquid Petroleum Part 3: Operation and Maintenance

1.5 Superseded Documents

This Document Type replaces the previously used document listed in Table 4

Table 4 Superseded Documents

Superseded Document	
Nil	

2 COVERAGE / SCOPE

This policy applies to all piggable hydrocarbon pipelines that fall within the scope of Australian Standard AS 2885.3 – 2012 Pipelines-Gas and liquid petroleum Part 3: Operations and maintenance.

This policy covers intelligent in line inspection (ILI) technologies including:

- Magnetic Flux Leakage (MFL)
- Geometry (Calliper Logging)
- XYZ
- EMAT
- Ultrasonic Crack Detection

This policy addresses criteria that can determine the frequency of initial and subsequent inspection runs including:

- Defect growth rate
- Regulated maximum interval
- Special integrity concerns
- Initial survey requirements
- Special considerations for High Consequence Areas (HCA)

Scope does not cover pipelines with third party ownership or licensee for these pipelines APA Group must comply with contractual arrangements. All recommendations to a third party licensee to perform an intelligent pig run shall be in accordance with this policy.

NOTES:
For non-piggable lines and lines where flow rates or operating pressures prevent effective ILI inspections approved alternate methods of determining structural integrity must be implemented. Alternate methods may include application of direct assessment methodology.

3 VALUES & COMMITMENTS

The policy promotes the safe and reliable delivery of energy in a safe environment.

This policy directs the determination of appropriate tools and inspection intervals for intelligent pigging, which is an important identifier of pipeline condition and a leading consideration in the review of pipeline structural integrity.

Dialogue should be maintained with all technical regulators to promote the deregulation of pigging frequencies in favour of a risk based approach.

Where APA Group begin operation of an existing pipeline due consideration of the pipeline's operational history must be applied.

4 POLICY

An engineering assessment addressing all of the criteria in this policy must be carried out in planning for all pipeline in line inspection (ILI) survey programs. The assessment shall determine:

- The appropriate ILI tools to be utilised.
- The appropriate initial inspection timing.
- The appropriate re-inspection interval.

The engineering assessment shall adopt a risk based methodology to determine if the normal initial inspection and re-inspection frequencies given in Section 4.1 are appropriate. If the calculated interval from the engineering assessment is less than that nominated in Section 4.1 the calculated interval must be adopted. Intervals longer than those nominated in Section 4.1 of this policy may be approved by the relevant Infrastructure Strategy & Engineering Manager.

Initial inspection requirements and timing for new assets shall be determined within 12 months of commissioning or of when the asset is acquired by APA and reviewed within 5 years or when new integrity threats are identified. All pipelines 6" and greater will be designed to be inspected by ILI where reasonably practical. Due to the inherent risks associated with ILI in smaller diameter pipelines these will generally not be inspected by ILI, however 'shorter length' sections with no internal weld beads or other similar obstructions may be considered on a case by case basis. Pigs will not be inserted into small diameter lines without risk assessment and approval by the relevant General Manager.

Re-inspection intervals shall be determined as soon as practicable after validation of initial or previous inspection runs and reviewed within 5 years or when changes that affect assumptions used in determining intervals are identified.

Every engineering assessment shall be approved by the relevant Integrity Manager/Engineer.

The Pipeline Integrity Management Plan will be maintained with the determined date and if necessary resigned by the Approver, detailed in the AS2885.3 Approvals Matrix 320-MX-AM-0001.

4.1 Selection and Timing of In Line Inspection Tools

4.1.1 Magnetic Flux Leakage – Axial Field

Regular inspection with traditional MFL tools with axial field direction is a minimum requirement under this policy for all pipelines. The normal time interval between commissioning and the first MFL and between subsequent MFL surveys is 10 years unless the engineering assessment determines otherwise.

4.1.2 Magnetic Flux Leakage – Circumferential Field

These MFL tools are specifically designed to detect long, narrow axially orientated metal loss defects. They may under some circumstances detect open axially aligned crack like defects and lack of fusion in seam welds. As resolution and detection capabilities of available tools currently do not meet those of high resolution traditional tools use of circumferential field tools in lieu of traditional (Axial field) MFL tools is not recommended under this policy however they may be utilised in addition to axial field tools to address specific integrity concerns or assist in discrimination of EMAT ILI crack indications.

4.1.3 Axial Field: Tri-Axial Sensors - Magnetic Flux Leakage

Tri-Axial MFL tools have been developed to provide higher resolution than traditional MFL tools and also enhance detection of long, narrow axially orientated metal loss defects.

Tri-Axial MFL tools are recommended in lieu of traditional MFL tools in high consequence areas and where extensive areas of corrosion are anticipated.

Where Tri-Axial MFL tools are utilised the normal time interval between commissioning and the first MFL and between subsequent MFL surveys is 10 years unless the engineering assessment determines otherwise.

4.1.4 Geometry (Calliper Logging) Tools

Regular inspection with intelligent geometry tools is a minimum requirement under this policy for all pipelines unless the engineering assessment determines dents are not a threat to integrity. Initial geometry surveys shall be conducted during commissioning or within 10 years of commissioning. The nominal interval between subsequent surveys is 20 years unless the engineering assessment determines otherwise.

Note: Engineering assessments determining geometry inspection intervals are to be reviewed where:

- Ground movement is reported or suspected.
- MFL inspections report excessive numbers of or previously unreported dents.
- Gauge plates detect increased levels of deformation over previous geometry or gauge pigs.

4.1.5 XYZ Surveys

An initial inspection with a XYZ tool is a minimum requirement under this policy for all pipelines unless the resolution of the 'as built' construction survey is sufficient for effective integrity management and location of defects detected by ILI. Initial XYZ surveys shall be conducted during commissioning or in conjunction with the next scheduled MFL inspection. Subsequent surveys are not required unless the engineering assessment determines otherwise.

Note: Engineering assessments determining XYZ inspection intervals are to be reviewed where ground movement is reported or suspected

4.1.6 EMAT Surveys

EMAT tools are specifically designed to detect axial cracking and are recommended for use in gas and liquid hydrocarbon pipelines where significant axial environmental cracking (Category II, III or IV determined using a safety factor of 1.39)[1] or longitudinal seam weld cracking has been detected by direct assessment methods. Initial inspections are to be completed as soon as practicable after detection of the significant cracking with subsequent re-inspection intervals to be determined by engineering assessment.

[1] Table 4.1: CEPA Stress Corrosion Cracking Recommended Practices, 2nd Edition, December 2007

4.1.7 Ultrasonic Crack Detection

Ultrasonic crack detection tools are specifically designed to detect axial cracking and are recommended for use in liquid hydrocarbon pipelines where significant axial environmental cracking or longitudinal seam weld cracking has been detected by direct assessment methods. Initial inspections are to be completed as soon as practicable after detection of the cracking with subsequent re-inspection intervals to be determined by engineering assessment.

Ultrasonic crack detection tools are not to be utilised in gas pipelines unless viable EMAT tools are unavailable and approval is obtained from the General Manager Infrastructure Strategy and Engineering.

4.1.8 Other Technologies

Other types of ILI tools currently on the market or under development are not recommended for integrity management of APA pipelines. APA will continue to encourage and monitor developments in ILI technology and review their applicability as a nationally co-ordinated activity. APA will endeavour wherever practicable to assist ILI vendors in development of new and existing technologies by providing access to pipelines for trial runs.

4.1.9 Vendor Selection

APA Group will maintain an agreement nationally with one or more ILI providers for the supply of tools and equipment. Use of any other vendors tools shall be approved by General Manager Infrastructure Strategy and Engineering.

Vendor ILI tool specifications shall be provided in accordance with the latest version of the Pipeline Operators Forum 'Specifications and requirements for intelligent pig inspection of pipelines' for the purposes of evaluating the suitability of tools for managing the integrity of APA pipelines.

In selecting vendors the specified probability of detection (POD) and probability of identification (POI) of features of concern shall be key criteria.

For pipelines with large numbers of detectable features higher resolution tools are recommended over lower resolution tools to minimise life cycle costs by reducing unnecessary repairs and potentially allowing longer re-inspection intervals.

4.2 Engineering Assessment Criteria

4.2.1 Defect Growth Rate

For time dependant corrosion growth (environmental cracking, internal and external corrosion) the pipeline is to be re-inspected no later than when:

1. The largest remaining unrepaired feature at the calculated average growth rate reaches the maximum size permitted for the "Safe" curve. or;
2. The largest remaining unrepaired feature at the calculated maximum growth rate has a failure pressure reaching the MAOP/MOP curve.

Supporting data to be utilised in determining growth rates may include:

- Internal or external growth rate determined from initial or multiple previous ILI inspections of the pipeline after validation of results.
- External growth rates determined from validated ILI inspections of pipelines with equivalent coating and cathodic protection levels operating in similar soil types and temperatures.
- Internal growth rates determined from validated ILI inspections of pipelines with equivalent gas or product composition.

Where specific corrosion information is known it will be utilised for corrosion growth assessment. Where information initial ILI inspection shall identify external corrosion development and the rate shall be deemed to be double the rate determined by calculating between construction and the ILI run date. This reflects an assumption that corrosion didn't actually commence at commissioning. For internal corrosion growth rates the period will be assumed to commence at commissioning and the rate will calculated directly from the ILI run data.

In the **absence of supporting growth data** minimum depth growth rates to be used in assessments are:

- Internal Corrosion – to be determined by engineering assessment based on gas composition.
- External Corrosion – 0.4 mm per year[2]
- Stress Corrosion Cracking – 0.6 mm per year

For features subject to fatigue failure, including dents and manufacturing/weld defects inspection intervals shall be 50% of calculated pressure cycles to failure.

Methodologies used for calculation of corrosion growth rate and fatigue failure must be approved by the National Integrity Management Engineer.

4.2.2 Regulated Maximum Pigging Interval

In some states there is a maximum interval between inspections dictated by Pipeline Regulation for particular pipelines. Where applicable, the timing between pigging shall be complied with, unless dispensation is granted by the regulator.

4.2.3 Special Integrity Concerns

Events that shall trigger a review of ILI tool use and frequency are:

- MAOP upgrades
- Remaining life review or design life extension.
- Class location changes.
- Natural events including earthquakes, major floods and landslips.
- Land subsidence, identification of acid sulphate soils or any other significant environmental change.
- Pipeline failure or failure of a similar pipeline, due to an undetected or unexpected defect.
- Detection of corrosion or cracking where growth rate exceeds rate used for calculation of inspection interval in accordance with 4.2.1.

[2] NACE SP 0502-2008

- Coupon corrosion rates exceeding the rate used for calculation of inspection interval in accordance with 4.2.1.
- Detection of significant SCC or other environmental cracking.
- Detection of seam weld cracking or lack of fusion/penetration of seam welds.
- Detection of narrow axial corrosion or selective corrosion at seam welds.
- Deterioration of cathodic protection levels or unexpected levels of coating deterioration
- Detection of steady state AC in excess of current acceptable levels.
- Changes in gas quality specification.
- Hydrostatic test failure during commissioning.

4.2.4 Initial Survey Requirements

The structural integrity of new pipelines is confirmed by hydrostatic testing, gauge pigging and a post construction coating defect survey. There is no specific requirement to perform initial benchmark ILI surveys, unless required by regulation.

Shortly after construction XYZ and geometry ILI surveys should be consider to establish a pipeline data benchmark and to provide 'as built' construction surveys.

Where hydrostatic test failure of a defect type that is known to have a low fatigue life occurs benchmark ILI surveys capable of detecting similar sub critical defects shall where practicable be carried out within 12 months or prior to expiry of the defect liability period.

4.3 High Consequence Areas

For any pipeline that passes through a high consequence area[3] and with physical and operating parameters that allow a critical defect to result in rupture as determined by AS2885.1, the approved engineering assessment must apply a 1.25 factor to any calculated time dependant growth rates used when establishing re-inspection intervals and 1.39 when calculating repair requirements.

Unless specifically determined otherwise the normal ILI requirements for pipelines passing through high consequence areas are:

- Tri-Axial MFL or combined axial and circumferential MFL inspections and;
- Geometry (Calliper logging) inspections (in conjunction with each MFL inspection).

Where practicable EMAT or dedicated circumferential field MFL inspections shall be carried out in pipelines in high consequence areas with:

- Unknown seam weld quality, or
- Very low seam weld toughness, or
- Historical seam weld or lamination hydro test failure, or
- Lack of fusion identified in seam welds during direct assessment programs.

EMAT inspections shall be carried out where practicable for pipelines in high consequence areas with:

- Known susceptibility to SCC.
- Hook cracks identified in seam welds.

[3] As defined in AS2885.1

New pipelines in high consequence areas shall be designed to be piggable. Existing un-piggable pipelines in high consequence areas shall wherever practicable be modified to accommodate in line inspections.

Note: Rupture of pipelines has occurred below 30% SMYS in pipelines with seam weld defects and combined dent/gouges. [4]

5 DOCUMENTATION AND REPORTING

The ILI inspection types and frequencies determined in accordance with this policy shall be documented in the Pipeline Integrity Management Plan (PIMP).

Approved defect growth rate and fatigue failure assessments carried out in accordance with this policy shall be documented and referenced in the PIMP.

Vendor ILI inspection reports shall be provided in a format that is compatible with the APA integrity data management tool (IDMT) and complies with the APA ILI data specification.

6 LINKS / INTERACTION WITH OTHER POLICIES

Key external standard documents that this policy has links to are:

- AS2885.3 – 2012 Pipelines-Gas and liquid petroleum Part 3: Operations and Maintenance.
- Pipeline Acts and Regulations.
- Pipeline Licences.

Related APA policies include:

- APA Asset Management Policy
- APA Pipeline Integrity Management Policy

Other related national APA documents include:

- APA Pipeline Management System
- National ILI pigging contract
- APA ILI Data Specification (Under development – to include data format standards, interaction rules, failure pressure calculation methodologies)
- APA Pigging Expert Guide (Under Development – to include risk management of pigging activities)
- APA Defect Assessment Guide (Under Development – to include assessment of ILI data sets, growth models, field assessment, defect acceptance criteria, and ILI validation guidelines)
- APA SCC Expert Guide (Under Development – SCC management practices for pipelines)
- APA Integrity Management of Un-piggable Pipelines Expert Guide (Under Development – to include direct and indirect assessment methodologies).

[4] Michael Rosenfield and Robert Fasset, 'Study of pipelines that ruptured while operating at a hoop stress below 30% SMYS', Pipeline Pigging and Integrity Management Conference, Houston, USA. February 2013.

7 PROCEDURES

Procedures, including those required by legislation will be developed for each application in accordance with the Pipeline Management System.

Confidential

Confidential

business case

dalby turbine overhaul

Business Case – Capital Expenditure

Dalby Turbine Overhaul

Business Case Number AA-08 – REVISION 1

1 Project Approvals

TABLE 1: BUSINESS CASE – PROJECT APPROVALS

Prepared By	Jen Ward, *Senior Pipeline and Asset Engineer, APA Group*
Reviewed By	Francis Carroll, *Engineering Services Manager QLD, APA Group*
Approved By	Craig Bonar, *Manager East Coast Grid Engineering, APA Group*

2 Project Overview

TABLE 2: BUSINESS CASE – PROJECT OVERVIEW

Description of Issue/Project	The RBP capacity relies on the compression service at Dalby which is the main midline compressor station, comprising a Solar Centaur 50 gas turbine compressor set. Gas turbine engines are subject to performance loss from normal wear and tear. In addition to ongoing maintenance and monitoring, APA undertakes Turbine Overhauls in accordance with company standard maintenance regimes and manufacturer recommendations, which is at or after manufacturer recommended life of 32,000 hours, up to a maximum of 50,000hrs (or as determined by engine condition assessment). The Dalby compressor no.2 (Centaur 50 turbine) was installed in 2012 and has passed 20,000 hours in 2016. It will be due for overhaul / change out within the next access arrangement period. No other compressors on the RBP are expected to require significant overhauls in this period.
Options Considered	The following options have been considered: 1. Option 1: Do Nothing Option – maintenance only past end of operating life 2. Option 2: Undertake overhaul inhouse 3. Option 3: Undertake overhaul as per OEM recommendations
Estimated Cost	$1.307 million
Consistency with the National Gas Rules (NGR)	The overhaul of the Dalby compressor No 2 complies with the capital expenditure criteria in Rule 79 of the NGR because: • it is necessary to maintain the integrity of services (Rules 79(2)(c)(ii); and • it is such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services (Rule 79(1)(a)).
Stakeholder Engagement	Availability and reliability of compression equipment on the RBP is required to maintain capacity for shippers. This is subject to commercial agreements involving customers.

3 Background

Dalby compressor station is the main compressor on the RBP with Unit 2 comprising a Solar Centaur 50 gas turbine and centrifugal compressor set. It also functions as a scraper station and the site also contains the now-decommissioned Unit 1 compressor set.

APA has national equipment regimes in place in the Enterprise Asset Management (EAM) system, APA's works management system, for Gas Turbine maintenance. Dalby Unit 2 is currently classified as a turbine for intermittent use and as such refers to the equipment maintenance regime number PL-M-20275.

In this regime, APA bases Solar Gas Turbine/Compressor servicing on OEM recommendations, utilising in-house labour for minor and medium services and contractor assistance (if required) for major services. In addition to routine checks, the regime requires a unit overhaul at its end of life. The OEM recommendation for end of life overhaul is at 32,000 hours. The APA regime allows this to be extended to a maximum of 50,000 hours before replacement/overhaul, provided that condition monitoring proves the turbine is suitable for ongoing operation.

Engine Condition Assessment and follow-up Gas Turbine overhauls are required to ensure security of gas supply by minimizing the risk of performance loss from normal wear and tear.

This is in line with standard operating practice and similar overhauls have been approved in previous AA periods. The much larger size of the C50 Solar Gas Turbines is reflected in the price paid for the overhaul. The Solar pricing schedule currently has this overhaul cost as $1.307 million, which includes the overhaul of gas producer, power turbine and auxiliary gear box. Installed in 2012, this unit had more than 20,000 operational hours in 2016. The 2022 forecast overhaul reflects the average usage of 5,000 hours per year to date continuing in the future.

The overall value of the compressor station upgrade including the Centaur 50 compressor package was > $20 million. Abandonment or decommissioning of the compressor, or complete replacement of the package, is not considered a realistic option in comparison to those presented in this Business Case.

4 Risk Assessment

Refer to the risk assessment table included as Appendix A to the Business Case. This risk assessment was carried out in accordance with the APA corporate risk policy and matrix.

TABLE 3: RISK RATING

Risk Area	Risk Level
Health and Safety	Low
Environment	Low
Operational	Moderate
Reputation	Low
Compliance	Moderate
Financial	Low
Final Untreated Risk Rating	Moderate

5 Options Considered

1.1 Option 1 – Do Nothing

- Do not undertake engine overhaul in accordance with manufacturer recommendations at end of engine life. Allow the turbine to deteriorate until failure.

1.1.1 Cost/Benefit Analysis

- Risk of engine failure from wear and tear and resulting loss of supply to customer – including cost of repair or machine replacement. If servicing is not carried out, turbine performance will deteriorate and the risk of a serious failure is elevated.

- The benefit of doing nothing is that there is no immediate cost for an overhaul at 32,000 to 50,000 hrs.

- If a failure occurred and the turbine was beyond its service life interval it is likely that it would be out of service for an extended period of time. Due to the unplanned nature of the outage, this would significantly affect customers downstream on the RBP including gas power generators at Oakey and Swanbank.

- The consequences of a turbine failure can in the worst case include a loss of containment of rotating parts or fuel gas, which have fire and safety implications that are protected by compressor shutdown and fire suppression systems. For this reason, personnel safety risk is deemed as Low.

1.2 Option 2 – Undertake Overhaul Inhouse

This option is not a viable option, given APA does not have the capability to overhaul a gas turbine on-site. This activity requires specialist knowledge and tools and equipment, including a clean environment in a manufacturer's workshop. Using specialist contractor for these overhauls also allows for warranty for any failures as applicable post overhaul and hence minimises any future financial risk.

1.3 Option 3 - Undertake Turbine Overhaul at required service life

- Undertake the machine overhaul at between 32,000 and 50,000 hrs, or upon engine condition assessment determination, in accordance with OEM recommendations. This involves removal of the turbine engine from the package and transport to the vendor, Solar Turbines, where it will be stripped down for a full overhaul/rebuild.

- APA has an Alliance Agreement with the OEM (Solar Turbines Australia) which provides for reduced costs for overhaul of engines provided the assessment indicates failure is not imminent. APA's policy is therefore to utilise periodic internal inspections and performance monitoring of the machines and to utilise their observed condition to extend the overhaul intervals where possible or intervene to prevent premature failure. An overhauled engine, power turbine and auxiliary gearbox are returned in zero hour condition, equivalent to new condition (turbine blades and wear parts such as discs, seals and shafts are re-worked or replaced as required).

- Under APA's agreement with Solar Turbines, this may be completed as an engine exchange programme, where an overhauled (zero-hour) Centaur 50 turbine engine is swapped out with the existing end-of-life engine. This option would not affect the cost of the overhaul.

- The included overhaul items include the Gas Producer (50L-6100 SoLoNOx), the Power Turbine (Centaur 50 Single Speed) and the Accessory Drive Gearbox.

1.3.1 Cost/Benefit Analysis

- The benefits of this option is the extension of the machine's operating life and minimises the risk of failure and loss of supply to customer.

- The costs include $1.140 million for the Gas Producer, $0.127 million for the Power Turbine and $0.040 million for the Accessory Gearbox, charged by Solar Turbines for the overhaul. Other minor costs include APA operations and engineering labour and cranage/transport costs which are not material.

1.4 Summary of Cost/Benefit Analysis

The section should include a general overview of how the options compare and identify any options are not technically feasible.

TABLE 4: SUMMARY OF COST/BENEFIT ANALYSIS

Option	Benefits (Risk Reduction)	Costs
Option 1	Do Nothing – run to failure	Nil immediate cost – potential future costs for failure, including replacement / repaired unit.

Option 2	Undertake Overhaul Inhouse – not practical given the inhouse capabilities do not exist (both expertise required and specialist tools / equipment). This is also not in line with our alliance agreement with the OEM.	Not determined
Option 3	Undertake overhaul at service life, as determined by condition monitoring or max 50,000 hrs. In line with OEM recommendations while maximizing life of the unit for cost efficiency.	$1.307 million

1.5 Proposed Solution

1.5.1 What is the Proposed Solution?

The proposed solution is Option 3, to continue the inspection regime as per the APA policy and complete an overhaul at between 32,000 and 50,000 hrs as determined by condition monitoring and engineering review.

1.5.2 Why are we proposing this solution?

Rotating plant require maintenance to ensure they continue to operate reliably. Gas turbine engines operate at high RPM speed with very close machine tolerances and it is necessary to remove the machines for manufacturer rebuild. This is standard practice in the gas pipeline industry.

OEM recommendations are for major rebuilds at intervals associated with the running hours and any extension of the running hours after 32,000 hrs requires performance monitoring and internal inspections to monitor the engine condition. The overhaul cannot be ignored as performance would degrade with additional running hours and ultimately component failure could result in catastrophic damage.

Implementing condition monitoring up to a maximum of 50,000 hrs before overhaul ensures optimum cost efficiency for this unit, in line with the EAM regime for this unit's service.

1.5.3 Consistency with the National Gas Rules

Rule 79(2)

The capex is consistent with rule 79(2) of the National Gas Rules as it is necessary in order to maintain the integrity of services (r79(2)(c)(ii)).

The overhaul keeps the compressor at Dalby in optimum operational condition. This reduces the risk of sudden compressor failure and loss of compression on the RBP when it is needed. Loss of compression would affect the ability to provide gas to users at times of high demand.

Rule 79(1)

Rule 79(1)(a) states:

> *the capital expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services*

This capital expenditure is consistent with rule 79 as it is:

Prudent – Overhauling the compressor in line with manufacturer's recommendations is the prudent course of action. Failure to do so will result in an increased risk of sudden compressor failure and resultant integrity risks for pipeline services.

Efficient – The option selected is the most cost effective long term option that meets the necessary operational requirements. The work was identified and considered under APA's expenditure framework. The timing of the overhaul is determined by monitoring engine condition as a means of not undertaking the work prematurely.

Consistent with accepted and good industry practice – Undertaking this work is consistent with standard industry practices and the manufacturers recommended service intervals. Similar overhauls have been approved by the AER in the past.

To achieve the lowest sustainable cost of delivering pipeline services – The overhauling the compressor ensures the lowest ongoing cost of providing compression services at Dalby.

1.5.4 Forecast Cost Breakdown

The forecast cost breakdown is based on the agreement with Solar for overhaul post-30,000 hrs.

The project cost of $1.307 million is entirely contractor costs payable to the overhaul vendor. APA costs such as operations and engineering labour, transport, parts and materials are included elsewhere in normal O&M costs.

Appendix A – Risk Assessment

	Section Description (as applicable):	Dalby Compressor Overhaul				
Risk Description			RISK - Before Treatment			
Category	Possible Consequence Description	Existing Control Measures	Frequency	Consequence	Risk	Comment/Basis
Health and Safety	Turbine / compressor failure - either component failure mechanical or worst case release of lube oil or fuel gas and subsequent fire hazard; Minor personnel injury worst case.	Compressor protection systems to shutdown; fire detection and suppression	Occasional	Minor	Low	
Environment	Possible loss of contianmnet, without impact to ecosystem		Occasional	Minor	Low	
Operational	Interruption more than 7 days of non-firm services but less than a month. Ability to rectify by one month (unless fire?)	Free flow supply for firm services most circumstances, options available through DN250;	Occasional	Medium	Moderate	
Reputation	Isolated adverse media coverage		Occasional	Minor	Low	
Compliance	Non-compliance related to inadequate operation of equipment outside industry practice - non-compliance with operatinonal license with scope for loss of license		Occasional	Medium	Moderate	
Financial	Likely impact of < $2.5M but < $12.5M in terms of revenue or construction repair costs		Occasional	Minor	Low	
Total Risk			Occasional	Medium	Moderate	

Solar Turbines
A Caterpillar Company

Strategic Agreement Pricing Letter

Submitted to:
APA GROUP

Date of Issue:
2/Feb/2016

Effectivity Date:
1/Feb/2016 to 1/Jan/2017

Submitted by:
Brett North

3.0 Rate Sheets

2016 Fired-Hour Overhaul Program Pricing - Discount NOT Included in Rates

Saturn 10 Range	Fired Hour Rate		Maximum Overhaul Running Fee	Maximum Overhaul Non-Running Fee	Disposition Fee	Exchange Program		
	Hours ≤ 40,000	Hours > 40,000				Exchange Fee	Daily Extended Core Return Fee	Maximum Extended Core Return Fee
Gas Producer <1>, <2>								
10-1000								
Two-Shaft (10-1001)	$2.61	$1.96	$123,839	$206,055	$13,705	$5,716	$176	$206,055
Single-Shaft (10-1020)	$2.69	$2.02	$127,967	$219,415	$20,051	$7,339	$192	$219,415
Single-Shaft (10-1021)	$2.69	$2.02	$127,967	$219,415	$20,051	$7,339	$192	$219,415
10-1200								
Two-Shaft	$2.61	$1.96	$123,839	$206,055	$13,705	$5,716	$176	$206,055
10-1300								
Two-Shaft	$2.91	$2.18	$138,287	$230,095	$13,705	$5,948	$197	$230,095
Power Turbine								
All Two-Shaft models	$0.64	$0.48	$30,272	$95,011	$3,847	$1,916	$112	$95,011
Exhaust Collector <3>								
Accessory Drive Gearbox								
MK I <4>	$0.33	$0.25	$15,824	$35,556	$4,218	$1,860	$37	$35,556
MK II	$0.25	$0.18	$11,696	$35,556	$4,261	$1,437	$41	$35,556
Output Drive								
MK I <4>	$0.39	$0.29	$18,576	$30,059	$3,132	$1,854	$25	$30,059
MK II	$0.19	$0.14	$8,944	$30,059	$2,789	$1,390	$36	$30,059
Reduction Gearbox								
50hz / 60hz	$0.81	$0.61	$36,655	$85,586	$11,706	$4,344	$117	$85,586

<1> *Recuperated units are no longer supported by Overhaul. Please contact PRU for upgrade options (refer to PIL 224 for additional information).*
<2> *Saturn 10-1000 should be priced as a Saturn 10-1200. Please check with DeSoto Project Manager for availability.*
<3> *Exhaust Collector (single-shaft units only) fixed price for overhaul/replacement is **$45,466**. Please check with DeSoto Project Manager for availability.*
<4> *Recommended TBO for MK I Accessory Gearboxes and Output Drives is 15,000 hours. Please refer to PIB 224 for service guidelines.*
*MKI AGB - For hours incurred ≤ 15,000, use **$0.33** per hour. For hours incurred > 15,000, use **$0.25** per hour.*
*MKI OPD - For hours incurred ≤ 15,000, use **$0.39** per hour. For hours incurred > 15,000, use **$0.29** per hour.*

2016 Fired-Hour Overhaul Program Pricing - Discount NOT Included in Rates

Saturn 20 Range	Fired Hour Rate		Maximum Overhaul Running Fee	Maximum Overhaul Non-Running Fee	Disposition Fee	Exchange Program		
	Hours ≤ 30,000	Hours > 30,000				Exchange Fee	Daily Extended Core Return Fee	Maximum Extended Core Return Fee
Gas Producer <1>								
20-1600								
Two-Shaft	$3.87	$2.90	$174,277	$273,293	$14,065	$7,801	$224	$273,293
Power Turbine								
All Two-Shaft models	$0.70	$0.53	$31,521	$95,011	$3,853	$1,974	$111	$95,011
Accessory Drive Gearbox								
MK II	$0.29	$0.21	$12,895	$35,556	$4,394	$1,958	$40	$35,556
Output Drive								
MK II	$0.27	$0.20	$12,179	$30,059	$3,009	$1,942	$33	$30,059
Reduction Gearbox								
50hz / 60hz	$1.06	$0.79	$47,567	$106,982	$11,706	$5,285	$147	$106,982

<1> *Recuperated units are no longer supported by Overhaul. Please contact PRU for upgrade options (refer to PIL 224 for additional information).*

Note: For Contract Customers, the prorated warranty runs to 40,000 hours.

2016 Fired-Hour Overhaul Program Pricing - Discount NOT Included in Rates

Centaur 40 Range Conventional Combustion	Fired Hour Rate		Maximum Overhaul Running Fee	Maximum Overhaul Non-Running Fee	Disposition Fee	Exchange Program		
	Hours ≤ 40,000	Hours > 40,000				Exchange Fee	Daily Extended Core Return Fee	Maximum Extended Core Return Fee
Gas Producer								
40-4000								
Two-Shaft - Conventional	$7.65	$5.74	$363,552	$738,030	$45,284	$26,940	$722	$738,030
40-4500								
Two-Shaft - Conventional	$8.44	$6.33	$401,047	$813,838	$45,284	$26,940	$796	$813,838
40-4700								
Two-Shaft - Conventional	$9.03	$6.77	$428,874	$846,564	$45,284	$26,940	$815	$846,564
Power Turbine								
Centaur 40								
Single Stage	$1.48	$1.11	$70,384	$117,146	$13,624	$4,584	$100	$117,146
Centaur 40L								
Two-Stage <3>	$2.18	$1.63	$103,464	$224,720	$15,450	$6,559	$228	$224,720
Accessory Drive Gearbox								
All Configurations	$0.36	$0.27	$16,892	$50,099	$5,548	$3,793	$58	$50,099
Reduction Gearbox								
50hz / 60hz	$1.37	$1.03	$61,858	$152,867	$24,759	$7,331	$209	$152,867

<1> *For a recuperated unit contact DeSoto Project Manager for availability (some components may have full lead-time).*

2016 Fired-Hour Overhaul Program Pricing - Discount NOT Included in Rates

Centaur 50 Range	Fired Hour Rate		Maximum Overhaul Running Fee	Maximum Overhaul Non-Running Fee	Disposition Fee	Exchange Program		
	Hours ≤ 30,000	Hours > 30,000				Exchange Fee	Daily Extended Core Return Fee	Maximum Extended Core Return Fee
Gas Producer								
50L-5900								
Two-Shaft - Conventional	$18.70	$14.03	$872,585	$1,090,732	$100,612	$40,356	$730	$1,090,732
Two-Shaft - SoLoNOx	$24.44	$18.33	$1,099,611	$1,374,513	$125,765	$60,055	$875	$1,374,513
50-6100								
Two-Shaft - Conventional	$19.40	$14.55	$905,067	$1,131,334	$100,612	$39,529	$757	$1,131,334
Two-Shaft - SoLoNOx	$25.35	$19.01	$1,140,544	$1,425,680	$125,765	$58,846	$908	$1,425,680
50L-6200								
Two-Shaft - Conventional	$19.87	$14.90	$927,214	$1,159,018	$100,612	$40,356	$776	$1,159,018
Two-Shaft - SoLoNOx	$25.97	$19.47	$1,168,453	$1,460,566	$125,765	$60,055	$930	$1,460,566
Power Turbine								
Centaur 50								
Single Stage	$1.97	$1.48	$127,407	$159,259	$16,453	$4,885	$145	$159,259
Centaur 50L								
Two Stage, Low Speed	$2.82	$2.11	$179,776	$224,720	$28,404	$6,985	$203	$224,720
Accessory Drive Gearbox								
All Configurations	$0.42	$0.32	$40,091	$50,114	$6,202	$4,040	$56	$50,114
Reduction Gearbox								
50hz / 60hz	$2.12	$1.59	$122,294	$152,867	$24,759	$10,620	$209	$152,867

2016 Fired-Hour Overhaul Program Pricing - Discount NOT Included in Rates

Taurus 60 Range	Fired Hour Rate		Maximum Overhaul Running Fee	Maximum Overhaul Non-Running Fee	Disposition Fee	Exchange Program		
	Hours ≤ 30,000	Hours > 30,000				Exchange Fee	Daily Extended Core Return Fee	Maximum Extended Core Return Fee
Gas Producer								
60-7800								
Two-Shaft - Conventional	$27.00	$20.25	$1,215,357	$1,519,196	$153,931	$63,627	$968	$1,519,196
Two-Shaft - SoLoNOx	$33.37	$25.03	$1,501,637	$1,877,046	$181,119	$86,179	$1,196	$1,877,046
Power Turbine								
Two Stage	$2.82	$2.11	$179,776	$224,720	$30,900	$7,599	$203	$224,720
Accessory Drive Gearbox								
All Configurations	$0.46	$0.34	$40,971	$51,214	$6,748	$4,395	$56	$51,214
Reduction Gearbox								
50hz / 60hz	$2.55	$1.91	$122,294	$152,867	$24,759	$12,726	$209	$152,867

2016 Fired-Hour Overhaul Program Pricing - Discount NOT Included in Rates

Mars Range	Fired Hour Rate		Maximum Overhaul Running Fee	Maximum Overhaul Non-Running Fee	Disposition Fee	Exchange Program		
	Hours ≤ 30,000	Hours > 30,000				Exchange Fee	Daily Extended Core Return Fee	Maximum Extended Core Return Fee
Gas Producer								
90-12000								
Two-Shaft - Conventional	$43.40	$32.55	$2,107,082	$2,633,853	$352,410	$117,256	$1,852	$2,633,853
Two-Shaft - SoLoNOx	$55.20	$41.40	$2,483,967	$3,104,959	$428,805	$152,566	$1,978	$3,104,959
90-13000								
Two-Shaft - Conventional	$45.61	$34.20	$2,214,279	$2,767,849	$352,410	$121,109	$1,946	$2,767,849
Two-Shaft - SoLoNOx	$58.01	$43.51	$2,610,338	$3,262,922	$428,805	$157,575	$2,078	$3,262,922
Power Turbine								
Two Stage	$3.73	$2.79	$354,784	$443,480	$54,334	$13,762	$494	$443,480
Accessory Drive Gearbox								
All Configurations	$2.06	$1.54	$111,458	$139,323	$20,093	$9,808	$110	$139,323
Reduction Gearbox <2>								
50hz / 60hz								

<1> *Mars 90-10000 should be priced as Mars 90-12000.*

<2> *Overhaul not available (performed by external suppliers).These gearboxes are serviced on a condition-based need, please refer to PIB 224 and PIL223 for detailed information on maintenance, repair and replacement options.*

Core Returns Schedule 2016

Daily Late Fees for Late Return of an Exchange Engine

An Exchange Fee is normally charged for the use of an Engine Assembly from Solar's Exchange Fleet. Under the terms and Agreement, Solar will waive the Exchange Fee if the used Core Engine Assembly (the "Core") is returned promptly to Solar's designated facility. "Prompt Return" is defined as within 14 days from the date of Ex Works shipment for on-shore installations within North America, Continental Europe and Australia, and within 21 days for offshore installations in those locations. For engines shipped into other areas, a "Prompt Return" is 75 days from the date of Ex Works shipment, or as otherwise agreed. If the used Core is not returned to the designated Solar facility within the allotted return period, a "Daily Late Fee" will be charged per day until the Core is received.

This Late Fee will be accrued daily and billed monthly. If a Core Engine Assembly is past due for one year, APA GROUP will be invoiced for the established list price for the Exchange Engine Assembly that Solar shipped to APA GROUP. The established List Price for the Exchange Engine Assembly is 80% of the applicable List Price for a New Engine Assembly of the same configuration. That amount will be reduced by the amount of any invoices paid for Engine Assembly Overhaul and/or Late Fees. After receipt of full payment, the Core Engine Assembly will become the property of APA GROUP.

The "Daily Late Fees" are detailed by engine model and assembly type in the attached pages.

Notes:

- Daily Late Fees are charged per day after the expiration of the Return Period up to the date of arrival of the Core at the designated Solar return facility. Daily Late Fees will be billed monthly.
- Daily Late Fees are charged in addition to the cost to overhaul the Core Engine Assembly.

Customer Location	**Point of Origin of EE**	**Return Location For Core**	**Return Period**	
			On-Shore	**Off-Shore**
PAFE - Australia	DeSoto	DeSoto	75	75
	DeSoto	Melbourne	75	75
	DeSoto	Zatec	75	75
	Melbourne	DeSoto	75	75
	Melbourne	Melbourne	60	60
	Melbourne	Zatec	75	75

COUNTRY/FACILITY MULTIPLIERS

The applicable Country/Facility multipliers should be applied to all exchange, new spare, uprate and/or SoLoNOx upgrade pricing, including associated fees, regardless of pricing method. Exchange fees are not subject to Facility Multiplier. Package system upgrade projects where Factory Pre-Commissioning Test is conducted at a facility other than Mabank has a different multiplier. Please contact Solar local office for pricing.

Facility multipliers should be applied to goods and services delivered and invoiced through such facility independent of where the work was performed.

Facility multipliers should also be applied to the max cap value as listed in this pricing letter.

COUNTRY	FACILITY MULTIPLIERS
DeSoto, TX, USA	1.00
Kuala Lumpur, Malaysia	1.20
Bandung, Indonesia	1.20
Melbourne, Australia	1.09
Gosselies, Belgium	1.13

Parts Delivery Multiplier

Solar's Service Parts are quoted from a standard worldwide price list in US Dollars, with delivery Ex Works from Ontario or San Diego, CA, USA, as applicable. The alternate Ex Works delivery locations listed below are offered for the convenience of regional operators. The Delivery Multipliers represent the cost of freight and importation expenses to the alternate Ex Works delivery location. The applicable Delivery Multiplier, as below, will be multiplied times the standard worldwide list price, after any applicable discount has been applied.

FACILITY	MULTIPLIER (DELIVERY)
San Diego, CA, USA	1.00
Ontario, CA, USA	1.00
Singapore	1.06
Melbourne, Australia	1.097

Notes:

- APA GROUP may elect to take delivery from any of the above standard delivery location they choose and the corresponding multiplier will be applied. Other delivery locations can be arranged, see your local Solar office for terms and pricing.
- Service Parts Prices, Ex Works Edmonton, Alberta, Canada, will be invoiced in Canadian Dollars and will include transportation and importation expenses, as agreed. This multiplier will be adjusted for the current exchange rate, which may vary throughout the year. Contact Solar's office in Edmonton for details and the current multiplier.

Field Service Rates 2016

Base Day	Australia, New Zealand & East Timor				PNG	
	FSR		RFE		FSR	RFE
	Onshore 10 Hours	Offshore 12 Hours	Onshore 10 Hours	Offshore 12 Hours	12 Hours	12 Hours
Monday - Friday	$2,266	$3,172	$3,168	$4,435	$3,172	$4,435
Saturday	$3,090	$4,079	$4,320	$5,702	$4,079	$5,702
Sunday	$4,120	$5,438	$5,760	$7,603	$5,438	$7,603
Blended Day Rate	$2,649	$3,626	$3,703	$5,069	$3,626	$5,069
Overtime Rates After Base Hours						
Monday - Saturday	$309	$340	$432	$475	$340	$475
Sundays	$412	$453	$576	$634	$453	$634

Public and local holidays will be charged at Sunday rates.

Commissioning Engineer/Project Manager: There are no unique charges for Field Service Representatives performing commissioning work. When a specialist is requested by Customer and Assigned by Commissioning Group to the Project, then a 20% adder should be used to price these Services.

Tooling Hire: All Regions

	Per Day
Borescope	$250
CSI	$250
Turbine Test Kit	$250
Emissions Analyzer	$250
Workshop & Miscellaneous Tools	Price upon request
Freight	Actual Cost + 15%

All Hire Charges are charged per day, door to door, i.e. from the time they leave Solar Turbines Australia, until the time they are returned.

Terms and Conditions: All Regions

Payment Schedule / Terms

- Payment schedule for the aforementioned scope of supply shall be 100% of order value, Net 30 days from date of Solar's invoice
- Regional Field Engineers will always be accompanied by a Field Service Representative which will be charged at current rates.
- Standby days will be charged at the applicable daily rate.

Goods and Services Tax (GST)

- All prices are quoted in AUD Dollars and are exclusive of GST or any other government/local taxes.

Field Service Rates for 2016

Validity: 01 February 2016 – 31 January 2017

Inclusions in Hours of Work

- Mobilisation/demobilisation of service personnel consist of chargeable man-days per person for travel to and from point of origin.
- Nightshift is defined as a planned work shift in which the work is expected to be performed between the hours of 18:00 and 06:00.
- Night Shift Policy: Solar requires three days advance notice for Field Service Personnel to work a night shift. A Standby Day is chargeable for each transition period from Day to Night and from Night to Day. Solar requires night shift conditions to meet the same safety standard as required for day shift work. No lifting or rigging of equipment by Solar personnel during night shift operations is permitted without the consent of the Solar District Service Manager. Solar Field Service Personnel must not work alone, or work more than 12 hours maximum in a 24 hour period while on night shift.
- Chargeable hours are comprised of working and travel hours.
- The minimum daily charge is half of the full day rate. Any hours over half of a standard day will result in the day being charged at a full day rate.
- Weekday overtime begins after the base day, including travel time.
- The minimum charge for weekends and Public Holidays is a full day.
- Offshore rates will apply in full for any partial days spent offshore.
- Reasonable time spent in preparation and procurement of special tools, test equipment, drawings, manuals, passports and visas, will be charged at regular rates.
- Once an RFE/FSR is mobilized by a customer, every day is a working day. If an RFE/FSR is available for work but not required by the customer to do so, the standby daily rate will be a charged.
- Solar personnel cannot exceed 14 hours of work per day without District Service Management approval. If this is given, a full ten-hour minimum rest period must be provided between work sessions.
- Field Personnel shall receive two breaks, a minimum of 48 hours in length, per month. Appropriate mobilisation and demobilisation charges will apply.

Accommodation & Travel Expenses

- Transportation costs such as rental cars, fuel, tolls, airfares, visas, taxi, rail, charter costs, etc., will be invoiced at actual cost plus 15%.
- Company-leased or personal auto costs will be charged at AUD$1.04 per km.
- All subsistence costs for accommodation, where applicable, will be invoiced at actual cost plus 15%.
- Receipts for expenses less than AUD $50.00 will not be provided.

Meals

- Subsistence cost for meals (if not provided) will be invoiced at a ‘per diem’ (daily) rate, as shown below for each day of mobilisation:
  - AUD $130 for Onshore Australia where meals are not provided.
  - AUD $175 for Onshore Papua New Guinea, New Zealand and East Timor where meals are not provided.
  - The rate for other locations will be discussed and agreed prior to mobilisation.
- Per Diem daily rate also applies for travel to and from site and/or when service personnel are on ‘stand by’.
- Receipts will NOT be provided for meals.
- All subsistence costs for accommodation, where applicable, will be invoiced at actual cost plus 15%
- Receipts for expenses less than AUD $50.00 will not be provided.

Sundry Materials

- Any Sundry materials purchased in support of the assignment will be invoiced at actual cost plus 15%.

Cancellation/Reschedule Policy

- Scheduled work cancelled or deferred between 72 and 48 hours prior to the start of trip shall be billed for the one full-day.

- Scheduled work cancelled or deferred between 48 and 24 hours prior to the start of trip shall be billed for the lesser of: two full-days or the duration of the scheduled assignment.
- Scheduled work cancelled or deferred between 24 and 0 hours prior to the start of trip shall be billed for the lesser of: three full-days or the duration of the scheduled assignment.

Service Requests and Payments: All Regions

- All requests for field service or technical assistance must include a completed Field Service Traveler document containing site location, engine or package serial number and scope of work. Requests should be sent to STAFieldservice@solarturbines.com.
- A purchase order must be provided with each request for support. Mobilisation cannot proceed until the purchase order is provided to Solar.

For clarification of any of the information provided please contact your local District Office.

Solar Gas Turbine/Compressor (Intermittent) Equipment Maintenance Regime			PL-M-20275	
Prepared by:	Hatch	Dale McPhie	**Status:**	Approved for Use
Reviewed by:	EAM SME's	Alan Fingers	**Version:**	0
Approved by:	APA Approver	Alan Fingers	**Issued:**	31/03/2015

1. SOURCE DATA

Doc. Type	Document Name	Doc. No.
Best of Breed	Oakey Compressor Station Solar Saturn S20 4000 hr Service	PM100 - WI0XX
Best of Breed	Oakey Compressor Station Solar Saturn S20 E & I Calibrations	PM100 - WI0XX
Best of Breed	Oakey Compressor Station Solar Saturn S20 8000 hr Service	PM100 - WI0XX
Best of Breed	QCS04 Solar Taurus Compressor Unit 2000, 4000 and 8000 hr Service Returnable	
Best of Breed	Solar Turbines 4000 Hour (Intermediate) Service Procedure & Report	STA/CCS/4000/SS
Supplementary	Davenport Downs Compressor Station Solar Centaur C50 4000 hr Service	PM100 - WI0XX
Supplementary	Davenport Downs Compressor Station Solar C50 Boroscope Inspection	PM100 - WI0XX
Supplementary	Davenport Downs Compressor Station Solar C50 Waterwash Procedure	PM100 - WI0XX
Supplementary	Davenport Downs Compressor Station Solar C50 E & I Calibrations	PM100 - WI0XX
Supplementary	Davenport Downs Compressor Station Solar Centaur C50 8000 hr Service	PM100 - WI0XX
Supplementary	Davenport Downs Compressor Station Solar Centaur C50 32000 hr Service	PM100 - WI0XX
Supplementary	Maintenance Schedules	OPS 509
Supplementary	Maintenance Plan Turee Creek	FM

2. FUNCTIONAL DESCRIPTION

The function of an Intermittent Solar Gas Turbine/Compressor is to supply gas at the required suction/ discharge pressure/temperature/flow rate on demand.

3. OVERARCHING STRATEGY

APA will base Solar Gas Turbine/Compressor servicing on OEM recommendations, utilising in-house labour for minor and medium services and contractor assist (if required) for major services.

Routine checks and oil sampling will be performed monthly. Minor services will be performed yearly and medium services at 4 and 5 years. Condition assessment by Engineering will commence from 32000 hours every 4000 hours, with a view to unit overhaul at or before 50000 hours by Contractor.

This regime variant will apply to all models of Solar Gas Turbine/Compressors with low use or intermittent duty (<4000 hours per year), in conjunction with the applicable master maintenance regime. The intent is to ensure minimum servicing tasks are completed on the unit, as running hours are low and may not trigger required servicing.

4. RELATED EQUIPMENT

Equipment	Asset Class Type	Function
Start System		Rotates engine to self-sustaining speed
Fuel System		Regulates fuel flow to engine, regulating speed and power
Electrical Control System		Monitors unit, controls shutdowns, protects equipment from hazards
Lube and Servo Oil Systems		Circulates correct quality and quantity of pressurised oil to engine, gear unit, bearings and controls
Enclosure and Ancillary Equipment		Provides suitable operating environment for unit
Air System		Provide correct quality and quantity of air to engine for combustion and operation
Turbine Engine	Gas turbines - Industrial	Maintains rotary motion at a set speed and power
Gas Compressor	Compressors - Centrifugal	Supplies gas at the required discharge pressure and/or flow rate
Seal System		Prevents cross contamination between process gas and lube oil

5. RELATED DOCUMENTS

Document Type	Document Name	Document Number
Manual	Solar Turbines, Centaur 40 Gas Turbine Driven Compressor Set, Operation and Maintenance Instructions	63351
Manual	Solar Turbines, Centaur 50 Gas Turbine Driven Compressor Set, Operation and Maintenance Instructions	3M613
Manual	Solar Turbines, Taurus 60 Gas Turbine Driven Compressor Set, Operation and Maintenance Instructions	3B731
Manual	Solar Turbines, Mars 90 Gas Turbine Driven Compressor Set, Operation and Maintenance Instructions	3P821

6. REVERSE FMEA

Equipment	Function	Functional Failure	Failure Mode	Failure Effect	Preventive Task/Action	Frequency	Duration (hrs)	Online/ Offline	Labour	Equipment	Parts
Start System	Rotates engine to self-sustaining speed	Reduced life	Lubricator failure	Component damage	Check pneumatic starter lubricator oil level and drip rate (if applicable)	Monthly		Online	1 Tech		
			Strainer deterioration	Component damage	Clean starter motor gas strainer (if applicable)	1 yearly		Offline	1 Tech	Hand tools	
			Strainer deterioration	Component damage	Clean auxiliary seal oil pump motor gas strainer (if applicable)	1 yearly		Offline	1 Tech	Hand tools	
		Fails to start engine	Valve deterioration	Production loss	Overhaul start system shut off valve (if applicable)	4 yearly		Offline	1 Tech	Hand tools	Shut off valve overhaul kit
			Valve deterioration	Production loss	Overhaul auxiliary seal oil pump shut off valve (if applicable)	4 yearly		Offline	1 Tech	Hand tools	Shut off valve overhaul kit
Fuel System	Regulates fuel flow to engine, regulating speed and power	Incorrect fuel flow	Incorrect adjustment	Performance loss	Record fuel gas pressure, adjust at off-skid regulator if necessary	Monthly		Online	1 Tech		
		Gas leakage	Seal failure	Safety hazard	Check fuel gas system for leaks	Monthly		Online	1 Tech		
		Loss of control	Linkage failure	Production loss	Inspect condition of fuel system linkages and connections	1 yearly		Offline	1 Tech		

Equipment	Function	Functional Failure	Failure Mode	Failure Effect	Preventive Task/Action	Frequency	Duration (hrs)	Online/ Offline	Labour	Equipment	Parts
		Unable to ignite	Igniter cable or plug deterioration	Production loss	Remove and inspect igniter cable for damage. Inspect igniter plug for erosion and proper gap. Replace if necessary	1 yearly		Offline	1 Tech	Hand tools	Igniter cable & plug
			Igniter torch deterioration	Production loss	Remove and inspect igniter torch housing for cracks or excessive erosion. Inspect discharge tube for chafing wear. Clean or replace as necessary	1 yearly		Offline	1 Tech	Hand tools	Igniter torch spares
			Injector deterioration	Component damage	Inspect fuel injectors for damage and clean	1 yearly		Offline	1 Tech	Hand tools	Fuel injector spares
		Reduced life	Filter deterioration	Component damage	Replace fuel gas valve solenoids pilot air /gas filter element and seals (if applicable)	1 yearly		Offline	1 Tech	Hand tools	Fuel gas pilot air filter element & seals
			Filter deterioration	Component damage	Replace fuel gas filter element and/or strainer and seals	1 yearly		Offline	1 Tech	Hand tools	Fuel gas filter element & seals
			Filter deterioration	Component damage	Wash & refit fuel control valve orifice filter (if applicable)	1 yearly		Offline	1 Tech	Hand tools	

Equipment	Function	Functional Failure	Failure Mode	Failure Effect	Preventive Task/Action	Frequency	Duration (hrs)	Online/ Offline	Labour	Equipment	Parts
Electrical Control System	Monitors unit, controls shutdowns, protects equipment from hazards	Loss of control	Incorrect indication	Performance loss	Inspect gauges and indicators for proper operation. Check all oil-filled gauges are filled and all indicating lamps are serviceable	Monthly		Online	1 Tech	Data sheet	
			Connection or wiring damage	Performance loss	Check condition of thermocouple harnesses	1 yearly		Offline	2 I/E Techs	Hand tools	Thermocouple harness gaskets
		Hazard not controlled	Overspeed monitor failure	Component damage Production loss	Test and calibrate backup overspeed monitor (OSM, if applicable)	1 yearly		Online/ Offline	2 I/E Techs	Calibration equipment	
			Device failure	Component damage Production loss	Test E-Stop/backup string devices	1 yearly		Offline	2 I/E Techs	Calibration equipment	
		Loss of control	Incorrect control sequencing	Performance loss	Restart turbine and record acceleration time. Monitor control system for proper sequencing	1 yearly		Online	2 I/E Techs		
			Connection or wiring damage	Production loss	Inspect control console electrical connections for cleanliness and security. Check wiring for absence of chafing and insulation damage	1 yearly		Offline	2 I/E Techs	Hand tools	
			Incorrect adjustment	Performance loss	Test speed and temperature topping system (relay systems only)	1 yearly		Offline	2 I/E Techs	Calibration equipment	

Equipment	Function	Functional Failure	Failure Mode	Failure Effect	Preventive Task/Action	Frequency	Duration (hrs)	Online/ Offline	Labour	Equipment	Parts
			Incorrect indication	Performance loss	Check and calibrate all temperature and pressure switches	1 yearly		Offline	2 I/E Techs	Calibration equipment	
		Hazard not controlled	Incorrect adjustment	Component damage Production loss	Test and calibrate as necessary all safety, warning, and shutdown devices and temperature/ pressure monitors	1 yearly		Offline	2 I/E Techs	Calibration equipment	
		Hazard not detected	Incorrect indication	Component damage Production loss	Test package vibration monitor	1 yearly		Offline	2 I/E Techs	Calibration equipment	
		Loss of control	Incorrect operation	Component damage Production loss	Check and calibrate anti surge valves	1 yearly		Offline	2 I/E Techs	Calibration equipment	
			Incorrect operation	Component damage Production loss	Verify anti surge system	1 yearly		Online	2 I/E Techs	Calibration equipment	
		Loss of control	Low battery power	Production loss	Change lithium battery in PLC, or controller	1 yearly		Offline	1 Tech	Hand tools	Lithium battery
Lube and Servo Oil Systems	Circulates correct quality and quantity of pressurised oil to engine, gear unit, bearings and controls	Incorrect oil quantity	Low oil level	Component damage	Check lube oil tank level, record oil consumption. Top up as necessary	Monthly		Online	1 Tech		Lube oil
			Loss of makeup oil	Component damage	Verify proper operation of oil makeup system (if applicable)	Monthly		Online	1 Tech		

Equipment	Function	Functional Failure	Failure Mode	Failure Effect	Preventive Task/Action	Frequency	Duration (hrs)	Online/ Offline	Labour	Equipment	Parts
		Loss of containment	Oil leakage	Safety hazard	Check lube oil system for leaks	Monthly		Online	1 Tech		
		Incorrect oil quality	Filter deterioration	Component damage	Check servo oil filter pop-up indicator, change element and seals if popped (if applicable)	Monthly		Online	1 Tech	Hand tools	Servo oil filter elements & seals
		Incorrect oil quality	Filter deterioration	Component damage	Check emergency backup pump lube oil filter pop-up indicator, change element and seals if popped	Monthly		Online	1 Tech	Hand tools	Emergency backup pump oil filter elements & seals
		Incorrect oil quality	Filter deterioration	Component damage	Check and record lube oil filter differential pressure. Change element and seals if limit exceeded	Monthly		Online	1 Tech	Hand tools	Lube oil filter elements & seals
		Incorrect oil quantity	Incorrect pressure setting	Component damage	Record lube oil pressure, adjust regulator if necessary.	Monthly		Online	1 Tech	Hand tools	
		Incorrect oil quality	Oil deterioration	Component damage	Take lube oil sample for laboratory analysis. Review results and replace oil as necessary	Monthly		Online	1 Tech		Oil sample kit
		Incorrect oil quantity	Motor failure	Component damage	Electrically test all electric motors including starter motors, oil pumps and fans.	1 yearly		Online	2 I/E Techs	Test equipment	

Equipment	Function	Functional Failure	Failure Mode	Failure Effect	Preventive Task/Action	Frequency	Duration (hrs)	Online/ Offline	Labour	Equipment	Parts
			Motor failure	Component damage	Service all electric motors including starter motors, oil pumps and fans. Lubricate all motors equipped with grease fittings. Check motor mountings security. Electrically test	1 yearly		Offline	2 I/E Techs	Test equipment	Grease
			Cooler fan damage	Component damage Deposits	Lubricate oil cooler fan shaft bearings and check for movement. Check fan blades for damage and hub bolt tension, correct as necessary	1 yearly		Offline	1 Tech	Hand tools	Grease
		Incorrect oil temperature	Cooler belt damage	Component damage Deposits	Check oil cooler belt tension and inspect for damage, misalignment or pulley wear (if applicable). Retension, replace or align as necessary	1 yearly		Offline	1 Tech	Hand tools	Oil cooler belts
			Cooler blockage	Component damage Deposits	Check oil cooler core for contamination, corrosion or damage. Clean or repair as necessary	1 yearly		Offline	1 Tech	Cleaning equipment	

Equipment	Function	Functional Failure	Failure Mode	Failure Effect	Preventive Task/Action	Frequency	Duration (hrs)	Online/ Offline	Labour	Equipment	Parts
		Incorrect oil quality	Filter deterioration	Component damage	Replace lube oil duty filter element and seals. Inspect and clean housing as necessary. Change over duty and standby filter positions.	1 yearly		Offline	1 Tech	Hand tools	Lube oil filter element & seals
		Incorrect oil quality	Filter deterioration	Component damage	Replace servo oil duty filter element and seals. Inspect and clean housing as necessary. Change over duty and standby filter positions.	1 yearly		Offline	1 Tech	Hand tools	Servo oil filter element & seals
		Incorrect oil temperature	Vent fan damage	Component damage Deposits	Check lube oil tank vent fan and mist precipitator for proper operation (if applicable)	1 yearly		Online	1 Tech		
		Hazard not controlled	Arrestor deterioration	Component damage	Clean all vent flame arrestors as necessary	1 yearly		Offline	1 Tech	Hand tools	
Enclosure and Ancillary Equipment	Provides suitable operating environment for unit	Overheating	Fan failure	Component damage	Lubricate enclosure vent fan electric motor bearings. Check motor mounting security and fan blades for damage	1 yearly		Offline	1 Tech	Hand tools	Grease

Equipment	Function	Functional Failure	Failure Mode	Failure Effect	Preventive Task/Action	Frequency	Duration (hrs)	Online/ Offline	Labour	Equipment	Parts
			Filter deterioration	Component damage	Inspect enclosure ventilation filters, clean or replace elements as necessary. Inspect housing and ductwork condition, remove contamination as necessary	1 yearly		Offline	1 Tech	Hand tools	Enclosure ventilation filter elements
		Not sealed	Door deterioration	Component damage	Inspect all enclosure doors for operation and sealing. Test door switches and lubricate hinges	1 yearly		Offline	1 Tech	Hand tools	Dry lubricant
Air System	Provide correct quality and quantity of air to engine for combustion and operation	Incorrect air quality/ quantity	Filter deterioration	Component damage Performance loss	Self-cleaning air filter - check supply pressure, manually cycle through cleaning operation, drain air reservoir tank (if applicable)	1 yearly		Online	1 Tech		
			Inlet blockage	Component damage Performance loss	Check air inlet system for obstructions and contamination	1 yearly		Offline	1 Tech	Hand tools	
		Reduced life	Intake/ exhaust system damage	Performance loss	Inspect air intake and exhaust systems for looseness, damage, leaks or debris	1 yearly		Offline	1 Tech	Hand tools	

Equipment	Function	Functional Failure	Failure Mode	Failure Effect	Preventive Task/Action	Frequency	Duration (hrs)	Online/ Offline	Labour	Equipment	Parts
			Filter deterioration	Component damage Performance loss	Inspect air inlet filter elements and record differential pressure. Replace elements as needed	1 yearly		Offline	1 Tech	Hand tools	Air filter elements
		Incorrect air quantity	Guide vane damage	Performance loss	Inspect engine compressor variable guide vane mechanism for wear or corrosion. Check for bent lever arms, loose fasteners, linkages or bushings and seized guide vanes	1 yearly		Offline	1 Tech		
			Guide vane damage	Performance loss	Apply corrosion inhibitor to variable guide vane system linkage (if applicable)	1 yearly		Offline	1 Tech		Corrosion inhibitor
		Reduced life	Filter deterioration	Component damage	Replace variable guide vane servo actuator filter elements and seals	1 yearly		Offline	1 Tech	Hand tools	Servo actuator filter elements & seals
		Incorrect air quantity	Bleed valve deterioration	Performance loss	Inspect bleed valve, actuator and ducting condition and operation	1 yearly		Offline	1 Tech	Hand tools	
			Bleed valve deterioration	Performance loss	Disassemble, clean, inspect and reassemble bleed valve (if applicable)	1 yearly		Offline	1 Tech	Hand tools	Bleed valve overhaul kit

Equipment	Function	Functional Failure	Failure Mode	Failure Effect	Preventive Task/Action	Frequency	Duration (hrs)	Online/ Offline	Labour	Equipment	Parts
		Reduced life	Filter deterioration	Component damage Performance loss	Replace self-cleaning air filter elements (if applicable)	5 yearly		Offline	1 Tech	Hand tools	Air filter elements
Turbine Engine	Maintains rotary motion at a set speed and power	Incorrect operation	Unusual behaviour	Component damage Performance loss	Check for any unusual operating condition (vibration, noise, etc.)	Monthly		Online	1 Tech		
			Line/ hose damage	Component damage Performance loss	Inspect all lines and hoses for leaks, wear or chafing. Correct as necessary	Monthly		Online	1 Tech	Hand tools	
			Linkage damage	Component damage Performance loss	Inspect all mechanical linkages for wear or looseness. Correct as necessary	Monthly		Online	1 Tech	Hand tools	
			Leakage	Safety hazard	Inspect entire package for fuel, oil and air leaks	Monthly		Online	1 Tech		
			Incorrect indication	Performance loss	Record nominated unit operating parameter readings from local and remote control panels. Review operational data to determine if engine requires a water wash	Monthly		Online	1 Tech		
			Leakage	Safety hazard	Check for PCD leaks	Monthly		Online	1 Tech		
			Fails to start	Production loss	Test run engine	Monthly		Online	1 Tech		

Equipment	Function	Functional Failure	Failure Mode	Failure Effect	Preventive Task/Action	Frequency	Duration (hrs)	Online/ Offline	Labour	Equipment	Parts
			Contaminant build up	Performance loss	Perform engine water wash	1 yearly		Offline	1 Tech	Hand tools Water wash cart	Deionised water ZOK detergent
			Contaminant build up	Performance loss	Conduct borescope inspection of turbine and report findings	1 yearly		Offline	1 Borescope Mech Tech	Borescope	Inspection port seals
			Contaminant build up	Component damage	Clean entire package	1 yearly		Offline	1 Tech	Cleaning equipment	
			Exhaust system damage	Performance loss	Inspect exhaust bellows for leaks, cracks or distortion. Check condition of exhaust stack supports, internals and drain. Correct as necessary	1 yearly		Offline	1 Tech	Height access equipment	
			Valve deterioration	Performance loss	Check condition and operation of solenoids, case drains and shut off valves	1 yearly		Offline	1 Tech		
			Bearing failure	Component damage	Replace drive shaft bearings (if applicable - Saturns only)	5 yearly		Offline	1 Tech	Hand tools	Drive shaft bearings
			Normal wear & tear	Performance loss	Perform engine condition assessment and determine overhaul hours (not Saturns or Centaur 40's)	32000 hrs		Online	Engineering	Operating, servicing & inspection records	

Equipment	Function	Functional Failure	Failure Mode	Failure Effect	Preventive Task/Action	Frequency	Duration (hrs)	Online/ Offline	Labour	Equipment	Parts
			Normal wear & tear	Performance loss	Perform engine condition assessment and determine overhaul hours (not Saturns or Centaur 40's)	36000 hrs		Online	Engineering	Operating, servicing & inspection records	
			Normal wear & tear	Performance loss	Perform engine condition assessment and determine overhaul hours	40000 hrs		Online	Engineering	Operating, servicing & inspection records	
			Normal wear & tear	Performance loss	Perform engine condition assessment and determine overhaul hours. Prepare for engine overhaul	44000 hrs		Online	Engineering	Operating, servicing & inspection records	
			Normal wear & tear	Performance loss	Remove, overhaul, reinstall and align engine (maximum service life 50000 hrs)	48000 hrs		Offline	Contractor 2 Techs	Lifting equipment Special tools	Overhaul kit
Seal System (Oil)	Prevents cross contamination between process gas and lube oil	Incorrect oil supply	Incorrect oil level/ temperature	Component damage Performance loss	Check seal oil degassing tank level and temperature (if applicable). Top up as necessary	Monthly		Online	1 Tech		Seal oil
			Incorrect oil flows	Component damage Performance loss	Check seal oil sight gauges for proper flow direction of oil and gas (if applicable)	Monthly		Online	1 Tech		
			Oil leakage	Safety hazard	Check seal oil system for leaks (if applicable)	Monthly		Online	1 Tech		

Equipment	Function	Functional Failure	Failure Mode	Failure Effect	Preventive Task/Action	Frequency	Duration (hrs)	Online/ Offline	Labour	Equipment	Parts
			Filter deterioration	Component damage Performance loss	Check seal oil filter, record differential pressure (if applicable). Change element if limit exceeded or pop-up indicator is popped	Monthly		Online	1 Tech	Hand tools	Seal oil filter elements & seals
		Incorrect oil supply	Coalescer deterioration	Component damage Performance loss	Check seal oil coalescer elements (if applicable). Replace as necessary	1 yearly		Offline	1 Tech	Hand tools	Seal oil coalescer elements & seals
			Filter deterioration	Component damage Performance loss	Replace seal oil supply filter elements and seals (if applicable)	1 yearly		Offline	1 Tech	Hand tools	Seal oil filter elements & seals
			Strainer deterioration	Component damage Performance loss	Inspect and clean seal oil trap inlet strainers (if applicable)	1 yearly		Offline	1 Tech	Hand tools	
			Valve deterioration	Component damage Performance loss	Check operation of seal oil and seal gas differential pressure regulating valves (if applicable)	1 yearly		Offline	1 Tech	Hand tools	Seal oil & seal gas differential pressure regulating valve overhaul kit
Seal System (Dry Gas)	Prevents cross contamination between process gas and lube oil	Incorrect air/ gas supply	Incorrect pressure settings	Component damage Performance loss	Check buffer air and dry gas seal pressure settings (if applicable)	Monthly		Online	1 Tech		

Equipment	Function	Functional Failure	Failure Mode	Failure Effect	Preventive Task/Action	Frequency	Duration (hrs)	Online/ Offline	Labour	Equipment	Parts
			Incorrect leakage rates	Component damage Performance loss	Check and record dry gas seal leakage on each end of compressor (if applicable)	Monthly		Online	1 Tech		
			Gas/air leakage	Safety hazard	Check dry gas seal system for leaks (if applicable)	Monthly		Online	1 Tech		
			Coalescer build up	Component damage Performance loss	Drain buffer air and dry gas seal coalescers (if applicable)	Monthly		Online	1 Tech		
			Filter deterioration	Component damage Performance loss	Check and record buffer air and dry gas seal coalescing filter differential pressures (if applicable). Replace elements if differential pressures exceed 138 kPa	Monthly		Online	1 Tech	Hand tools	Buffer air & seal gas filter elements & seals
			Filter deterioration	Component damage Performance loss	Replace buffer air and dry gas seal coalescing duty filter elements and seals (if applicable). Change over duty and standby filter positions.	1 yearly		Offline	1 Tech	Hand tools	Buffer air & seal gas filter elements & seals
			Valve deterioration	Component damage Performance loss	Check operation of dry gas seal system differential pressure regulating valves (if applicable)	1 yearly		Offline	1 Tech	Hand tools	Differential pressure regulating valve overhaul kit

7. JOB PLANS

Job Plan No. 1	Solar Gas Turbine/Compressor (Intermittent) Monthly Checks	
Frequency	Monthly	
Plant Operations	Online	
Attachments	SWM-R-20117 (SWMS) WI-M-20241 (Work Instruction)	
Resources		
Labour	1 Technician	3 hours
Equipment	Data sheet Hand tools	
Parts	Oil sample kit	
Job Plan		
1.	Initial Preparation	
2.	Test run engine.	
3.	Check pneumatic starter lubricator oil level and drip rate (if applicable).	
4.	Record fuel gas pressure, adjust at off-skid regulator if necessary.	
5.	Check fuel gas system for leaks.	
6.	Inspect gauges and indicators for proper operation. Check all oil-filled gauges are filled and all indicating lamps are serviceable.	
7.	Check lube oil tank level, record oil consumption. Top up as necessary.	
8.	Verify proper operation of oil makeup system (if applicable).	
9.	Check lube oil system for leaks.	
10.	Check servo oil filter pop-up indicator, change element and seals if popped (if applicable).	
11.	Check emergency backup pump lube oil filter pop-up indicator, change element and seals if popped.	
12.	Check and record lube oil filter differential pressure. Change element and seals if limit exceeded.	
13.	Record lube oil pressure, adjust regulator if necessary.	

14.	Take lube oil sample for laboratory analysis. Review results and replace oil as necessary.
15.	Check for any unusual operating condition (vibration, noise, etc.).
16.	Inspect all lines and hoses for leaks, wear or chafing. Correct as necessary.
17.	Inspect all mechanical linkages for wear or looseness. Correct as necessary.
18.	Inspect entire package for fuel, oil and air leaks.
19.	Record nominated unit operating parameter readings from local and remote control panels. Review operational data to determine if engine requires a water wash.
20.	Check for PCD leaks.
21.	Check seal oil degassing tank level and temperature (if applicable). Top up as necessary.
22.	Check seal oil sight gauges for proper flow direction of oil and gas (if applicable).
23.	Check seal oil system for leaks (if applicable).
24.	Check seal oil filter, record differential pressure (if applicable). Change element if limit exceeded or pop-up indicator is popped.
25.	Check buffer air and dry gas seal pressure settings (if applicable).
26.	Check and record dry gas seal leakage on each end of compressor (if applicable).
27.	Check dry gas seal system for leaks (if applicable).
28.	Drain buffer air and dry gas seal coalescers (if applicable).
29.	Check and record buffer air and dry gas seal coalescing filter differential pressures (if applicable). Replace elements if differential pressures exceed 138 kPa.
30.	Job Completion

Job Plan No. 2	Solar Gas Turbine/Compressor (Intermittent) Yearly Service
Frequency	Yearly
Plant Operations	Offline
Attachments	SWM-R-20115 (SWMS) WI-M-20243 (Work Instruction)
Resources	

Labour	2 I/E Technicians 1 Mechanical Technician 1 Mechanical Technician competent in Borescope inspection	80 hours
Equipment	Data sheet Hand tools Calibration equipment Test equipment Cleaning equipment Water wash cart Borescope Height access equipment	
Parts	Lube oil filter elements & seals Oil sample kit Fuel gas pilot air filter element & seals Thermocouple harness gaskets Fuel gas filter element & seals Grease Buffer air & seal gas filter elements & seals Servo oil filter elements & seals Seal oil filter elements & seals Lithium battery Deionised water ZOK detergent Dry lubricant Corrosion inhibitor Servo actuator filter elements & seals Bleed valve overhaul kit	
Job Plan		
1.	Initial Preparation	
2.	Unit Isolations	
3.	Clean starter motor gas strainer (if applicable).	
4.	Clean auxiliary seal oil pump motor gas strainer (if applicable).	
5.	Inspect condition of fuel system linkages and connections.	
6.	Remove and inspect igniter cable for damage. Inspect igniter plug for erosion and proper gap. Replace if necessary.	
7.	Remove and inspect igniter torch housing for cracks or excessive erosion. Inspect discharge tube for chafing wear. Clean or replace as necessary.	
8.	Inspect fuel injectors for damage and clean.	
9.	Replace fuel gas valve solenoids pilot air /gas filter element and seals (if applicable).	
10.	Replace fuel gas filter element and/or strainer and seals.	
11.	Wash & refit fuel control valve orifice filter (if applicable).	

12.	Check condition of thermocouple harnesses.
13.	Test and calibrate backup overspeed monitor (OSM, if applicable).
14.	Test E-Stop/backup string devices.
15.	Inspect control console electrical connections for cleanliness and security. Check wiring for absence of chafing and insulation damage.
16.	Test speed and temperature topping system (relay systems only).
17.	Check and calibrate all temperature and pressure switches.
18.	Test and calibrate as necessary all safety, warning, and shutdown devices and temperature/ pressure monitors.
19.	Test package vibration monitor.
20.	Check and calibrate anti surge valves.
21.	Change lithium battery in PLC, or controller.
22.	Service all electric motors including starter motors, oil pumps and fans. Lubricate all motors equipped with grease fittings. Check motor mountings security. Electrically test.
23.	Lubricate oil cooler fan shaft bearings and check for movement. Check fan blades for damage and hub bolt tension, correct as necessary.
24.	Check oil cooler belt tension and inspect for damage, misalignment or pulley wear (if applicable). Retension, replace or align as necessary.
25.	Check oil cooler core for contamination, corrosion or damage. Clean or repair as necessary.
26.	Replace lube oil duty filter element and seals. Inspect and clean housing as necessary. Change over duty and standby filter positions.
27.	Replace servo oil duty filter element and seals. Inspect and clean housing as necessary. Change over duty and standby filter positions.
28.	Clean all vent flame arrestors as necessary.
29.	Lubricate enclosure vent fan electric motor bearings. Check motor mounting security and fan blades for damage.
30.	Inspect enclosure ventilation filters, clean or replace elements as necessary. Inspect housing and ductwork condition, remove contamination as necessary.
31.	Inspect all enclosure doors for operation and sealing. Test door switches and lubricate hinges.
32.	Check air inlet system for obstructions and contamination.
33.	Inspect air intake and exhaust systems for looseness, damage, leaks or debris.
34.	Inspect air inlet filter elements and record differential pressure. Replace elements as needed.

35.	Inspect engine compressor variable guide vane mechanism for wear or corrosion. Check for bent lever arms, loose fasteners, linkages or bushings and seized guide vanes.
36.	Apply corrosion inhibitor to variable guide vane system linkage (if applicable).
37.	Replace variable guide vane servo actuator filter elements and seals.
38.	Inspect bleed valve, actuator and ducting condition and operation.
39.	Disassemble, clean, inspect and reassemble bleed valve (if applicable).
40.	Conduct borescope inspection of turbine and report findings.
41.	Clean entire package.
42.	Inspect exhaust bellows for leaks, cracks or distortion. Check condition of exhaust stack supports, internals and drain. Correct as necessary.
43.	Check condition and operation of solenoids, case drains and shut off valves.
44.	Check seal oil coalescer elements (if applicable). Replace as necessary.
45.	Replace seal oil supply filter elements and seals (if applicable).
46.	Inspect and clean seal oil trap inlet strainers (if applicable).
47.	Check operation of seal oil and seal gas differential pressure regulating valves (if applicable).
48.	Replace buffer air and dry gas seal coalescing duty filter elements and seals (if applicable). Change over duty and standby filter positions.
49.	Check operation of dry gas seal system differential pressure regulating valves (if applicable).
50.	Perform engine water wash.
51.	Unit De-Isolations
52.	Unit Recommissioning
53.	Electrically test all electric motors including starter motors, oil pumps and fans.
54.	Restart turbine and record acceleration time. Monitor control system for proper sequencing.
55.	Verify anti surge system.
56.	Check lube oil tank vent fan and mist precipitator for proper operation (if applicable).
57.	Self-cleaning air filter - check supply pressure, manually cycle through cleaning operation, drain air reservoir tank (if applicable).

58.	Perform Monthly Checks
59.	Job Completion

Job Plan No. 3	Solar Gas Turbine/Compressor (Intermittent) 4 Yearly Service	
Frequency	4 Yearly	
Plant Operations	Offline	
Attachments	SWM-R-20115 (SWMS) WI-M-20244 (Work Instruction)	
Resources		
Labour	2 I/E Technicians 1 Mechanical Technician 1 Mechanical Technician competent in Borescope inspection	8 hours
Equipment	Data sheet Hand tools Calibration equipment Test equipment Cleaning equipment Water wash cart Borescope Height access equipment	
Parts	Lube oil filter elements & seals Oil sample kit Fuel gas pilot air filter element & seals Thermocouple harness gaskets Fuel gas filter element & seals Grease Buffer air & seal gas filter elements & seals Servo oil filter elements & seals Seal oil filter elements & seals Lithium battery Deionised water ZOK detergent Dry lubricant Corrosion inhibitor Servo actuator filter elements & seals Bleed valve overhaul kit Shut off valve overhaul kit	
Job Plan		
1.	Initial Preparation	
2.	Unit Isolations	
3.	Perform Yearly Service	

4.	Overhaul start system shut off valve (if applicable).	
5.	Overhaul auxiliary seal oil pump shut off valve (if applicable).	
6.	Unit De-Isolations	
7.	Unit Recommissioning	
8.	Perform Monthly Checks	
9.	Job Completion	

Job Plan No. 4	Solar Gas Turbine/Compressor (Intermittent) 5 Yearly Service	
Frequency	5 Yearly	
Plant Operations	Online	
Attachments	SWM-R-20115 (SWMS) WI-M-20245 (Work Instruction)	
Resources		
Labour	1 Technician	8 hours
Equipment	Hand tools	
Parts	Air filter elements Drive shaft bearings	
Job Plan		
1.	Initial Preparation	
2.	Unit Isolations	
3.	Perform Yearly Service	
4.	Replace self-cleaning air filter elements (if applicable)	
5.	Replace drive shaft bearings (if applicable - Saturns only)	
6.	Unit De-Isolations	
7.	Unit Recommissioning	

8.	Perform Monthly Checks
9.	Job Completion

Job Plan No. 5	Solar Gas Turbine/Compressor (Intermittent) Engine Condition Assessment	
Frequency	Every 4000 Hours, from 32000 to 44000 Hours Every 4000 Hours, from 40000 to 44000 Hours (Saturns & Centaur 40's)	
Plant Operations	Online	
Attachments	SWM-R-20117 (SWMS) WI-M-20233 (Work Instruction)	
Resources		
Labour	1 Engineer	8 hours
Equipment	Operating, servicing and inspection records	
Parts		
Job Plan		
1.	Initial Preparation	
2.	Perform engine condition assessment and determine overhaul hours.	
3.	Job Completion	

Job Plan No. 6	Solar Gas Turbine/Compressor (Intermittent) Engine Overhaul	
Frequency	50000 Hours (maximum service life, or as determined necessary by Engine Condition Assessment)	
Plant Operations	Offline	
Attachments	SWM-R-20116 (SWMS) WI-M-20240 (Work Instruction)	
Resources		
Labour	1 Contractor 2 Technicians	40 hours
Equipment	Hand tools Special tools Lifting equipment	

Parts	Overhaul kit
Job Plan	
1.	Initial Preparation
2.	Unit Isolations
3.	Remove, overhaul, reinstall and align engine
4.	Unit De-Isolations
5.	Unit Recommissioning
6.	Job Completion