Final Plan Attachment 8.6

Business Cases

December 2016

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Information Technology Business Cases

Business Case	Capex Value ($2016)
V46 Applications Renewal	$22m
V47 Business Intelligence	$11m
1 Supporting Information 1: NPV & Options Analysis	
2 Supporting Information 2: ESV GPI Safety Management Report Executive Briefing	
3 Supporting Information 3: ESV GPI Safety Management Report 2014/15 Non-Licensed Gas Infrastructure	
V48 Mobility Integration	$10m
1 Supporting Information 1: NPV & Options Analysis	
2 Supporting Information 2: ESV GPI Safety Management Report Executive Briefing	
3 Supporting Information 3: ESV GPI Safety Management Report 2014/15 Non-Licensed Gas Infrastructure	
V49 GIS Upgrade	$16m
1 Supporting Information 1: ESV GPI Safety Management Report Executive Briefing	
2 Supporting Information 2: ESV GPI Safety Management Report 2014/15 Non-Licensed Gas Infrastructure	
V50 Infrastructure Renewal	$1m
V104 Development of Digital Capabilities	$1m
1 Supporting Information 1: ISOBAR Proposal	
2 Supporting Information 2: Technical Audit	
3 Supporting Information 3: Industry Landscape Audit	
4 Supporting Information 4: Situational Analysis	
5 Supporting Information 5: Digital Vision	

Note: Supporting Information files have been provided separately.

Business Case – Capex V46

Applications Renewal

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	Trevor Coles, Applications Manager Information Technology
Approved By	Bill Fazl, General Manager Information Technology

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	The Applications Renewal project is required to ensure that Australian Gas Networks Limited's (AGN) critical Information Technology (IT) applications are kept up-to-date over the next (2018 to 2022) Access Arrangement (AA) period and to embed the benefits of the IT systems nationalisation program that commenced in the current (2013 to 2017) AA period. This project involves systematically upgrading the nationalised software and applications that manage AGN's operational business in Victoria and Albury. The key objectives of this project are to: • continue to maintain reliable, secure, compliant and efficient business processes and systems; • preserve the ongoing integrity of AGN's services; and • enable AGN to continue to comply with a range of regulatory and other obligations. The key benefits of this project are to substantially reduce the risk of system(s) failure or integration between systems not working as required and maintaining the levels of systems security and data integrity. The work proposed in this business case forms part of the National Applications Renewal project across all jurisdictions AGN operates in. The South Australian (SA) component of this project[1] has been recently approved by the Australian Energy Regulator (AER) in its Final Decision on AGN's AA for the 2016/17 to 2021/22 AA period[2]. In approving this project, the AER noted that it was satisfied that the project was "justified as necessary under rule 79(2)(c)" of the National Gas Rules (NGR) and was "conforming capex that complies with rule 79" of the NGR"[3].
Options Considered	The following options have been considered to address the risks posed by outdated applications: 1 Option 1: Do Nothing.

[1] AGN, "*Access Arrangement 2016-21 proposal*", Attachment 7.1_Business Cases.pdf, "*Business case SA57 - South Australian Applications Renewal project for the FY2016/17 to FY2020/21 AA period*", July 2015.

[2] AER, "*Final Decision: Australian Gas Networks Access Arrangement 2016 to 2021, Attachment 6 – Capital Expenditure*", May 2016, pg. 6-33.

[3] AER, "*Draft Decision: Australian Gas Networks Access Arrangement 2016 to 2021, Attachment 6 – Capital expenditure*", November 2015, pg. 6-41.

	2 Option 2: Upgrade critical IT applications on a regular basis consistent with AGN's application lifecycle management methodology.
Proposed Solution	Option 2 has been selected because it is the most cost effective way of dealing with the risks posed by outdated and unsupported applications and is consistent with good industry practice.
Estimated Cost	$22,041.1 ($000, 2016) capital expenditure (capex).

Consistency with the National Gas Rules (NGR)	The Applications Renewal project complies with the new capex criteria in rule 79 of the National Gas Rules (NGR) because:
	• 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)); and
	• it is justified under rule 79(2)(c) because it is required to:
	  • *maintain and improve the safety of services (rule 79(2)(c)(i))* - the safety of services will be adversely affected if there is a security breach and/or any of the critical IT systems fails;
	  • *maintain the integrity of services (rule 79(2)(c)(ii))* - the integrity of the services will be adversely affected if critical systems are unavailable; and
	  • *comply with a regulatory obligation or requirement (rule 79(2)(c)(iii))* – the project mitigates the risk of a breach of regulatory obligations (e.g. Retail Market Procedures requirements for processing timeframes) if key systems are not available or customer data is compromised.

Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Safety and Reliability themes as its implementation will allow AGN to maintain the safety of the network whilst continuing to provide a highly reliable supply of natural gas to our customers by reducing the risk of IT system failures and security risks. More information detailing the results of AGN's stakeholder engagement program is provided in Chapter 5 of the Access Arrangement Information document.

1.3. Background

Australian Gas Networks Limited (AGN) maintains and operates a number of critical Information Technology (IT) systems that are integral to the efficient and effective management of the Victorian and Albury networks and are required to meet a range of legal and regulatory obligations, including those prescribed in the:

- the National Gas Law (NGL) and National Gas Rules (NGR);
- the Victorian Gas Distribution System Code[4];
- the Victorian Gas Industry Act 2001[5]; and
- the Victorian Retail Market Procedures[6] (RMP).

They are also required to meet Energy Safe Victoria's (ESV's) gas and pipeline safety requirements[7].

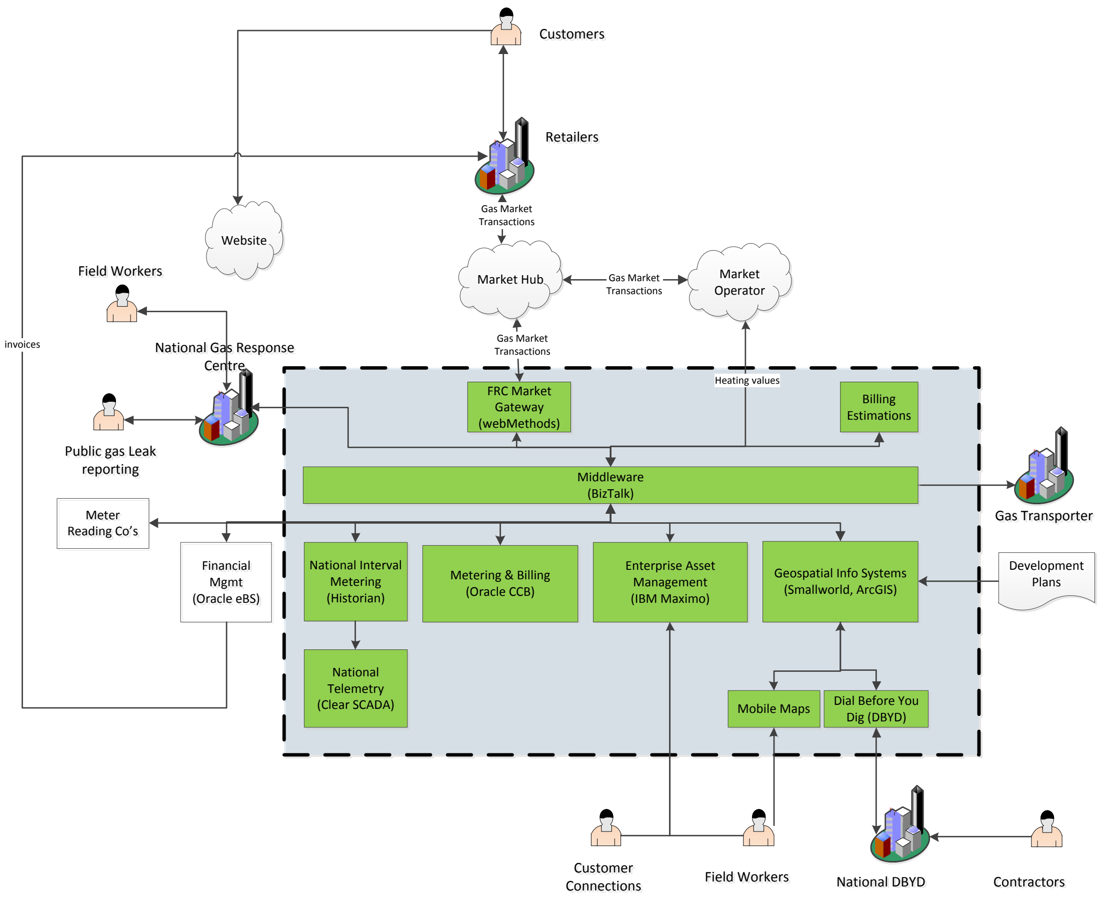
4 Essential Services Commission, "*Gas Distribution System Code*", Version 11.0.
5 http://www.austlii.edu.au/au/legis/vic/consol_act/gia2001167/
6 AEMO, http://www.aemo.com.au/Gas/Policies-and-Procedures/Retail-Gas-Market-Procedures/Victoria
7 http://www.esv.vic.gov.au/About-ESV

As a prudent operator, AGN has ongoing maintenance plans for its critical IT systems, which are based on the appropriate risk assessments, to ensure continued compliance with these legal, regulatory and safety obligations.

1.3.1. AGN's IT environment

Given the highly integrated nature of AGN's IT environment, upgrades and improvements to these systems have been incorporated into a detailed *Information Technology Investment Plan*[8] (IT Plan), which has been provided as Attachment 8.5 to AGN's Access Arrangement Information (AAI) document.

Figure 1: AGN IT architecture



This IT Plan details the proposed IT capital program of work over the next AA period, as well as acting to support AGN's business objectives, which, in turn, are aligned with the stakeholder expectations identified during the stakeholder engagement program recently undertaken by AGN in Victoria and Albury[9].

In the current AA period, a number of major projects to nationalise and upgrade key IT application systems were implemented. These projects delivered improved IT systems with increased scalability, flexibility and reliability, while also ensuring that AGN continues to meet its obligations under the RMP and other relevant regulatory and customer obligations. The IT

8 APA, *"Victorian and Albury Networks Information Technology Investment Plan for the 2018 to 2022 Access Arrangement Period"*, July 2016

9 Deloitte, *"Australian Gas Networks Customer Insights Report, Victorian and Albury Stakeholder Engagement Program"*, May 2016.

systems nationalisation program has so far successfully delivered to Victoria and Albury the Enterprise Asset Management (EAM) system, the National Metering and Billing (MnB) system and other core foundation platforms to leverage efficiencies in business operations through data consolidation, enablement of standard national processes and task automation.

Additional projects to complete the nationalisation program during the next (2018 to 2022) AA period have been included in separate business cases. The completion of the nationalisation program of work is required in order for AGN to realise the full business benefits from moving towards the national enterprise structure and the integrated suite of systems, including enhanced EAM capability, streamlined and scaled applications and processes, and improved risk mitigation. The ultimate beneficiaries of these improvements will be AGN's customers.

The work proposed in this business case forms part of the National Applications Renewal project across all jurisdictions AGN operates in. The related project for the South Australian (SA) AGN network[10] has been recently approved by the AER in its Final Decision on AGN's AA for the 2016/17 to 2021/22 AA period. In approving this project, the AER noted that it was satisfied that the project was "*justified as necessary under rule 79(2)9(c)*" and was "*conforming capex that complies with rule 79*" of the NGR."[11]

1.3.2. Objectives of the Applications Renewal project

The Applications Renewal project is required to embed the benefits of the IT systems nationalisation program, maintain the current levels of IT services, maintain security and mitigate risks associated with AGN's core business systems.

The Applications Renewal project will involve systematically upgrading the nationalised software and applications that manage AGN's operational business in Victoria and Albury, in accordance with good industry practice and AGN's application lifecycle management methodology. The applications in question include:

- Billing Estimation Model;
- Dial Before You Dig System;
- Metering & Billing System;
- Enterprise Asset Management;
- Geospatial Information System;
- Telemetry System;
- Historian System;
- FRC Market Gateway;
- Middleware – BizTalk; and
- Field Data / Mobility

The key objectives of this project are to:

- continue to maintain reliable, secure, compliant and efficient business processes and systems;
- preserve the ongoing integrity of these services; and

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10 AGN, *"Business case SA57 - South Australian Application Renewal project for the FY2016/17 to FY2020/21 AA period", July 2015*

11 AER, *"Final Decision: Australian Gas Networks Access Arrangement 2016 to 2021, Attachment 6 – Capital Expenditure"*, May 2016, p. 6-33 and AER, *"Draft Decision: Australian Gas Networks Access Arrangement 2016 to 2021, Attachment 6 – Capital expenditure",* November 2015, p. 6-41.

- comply with the AGN's legislative and regulatory obligations under the various instruments set out above, including the RMP[12] (see example in Box 1.1).

The key benefits from this project are to substantially reduce the level of risk of system(s) failure or integration between systems not working as required and maintaining the levels of systems security.

Box 1.1: AGN's obligations under the Retail Market Procedures

In accordance with Section 1.2 of the Retail Market Procedures, the Australian Energy Market Operator (AEMO) established a Gas Interface Protocol (GIP), which governs the manner and form in which information is to be provided, notice given, notices or documents delivered and requests made as contemplated by the RMP. Further, Section 1.2.4 of the RMP states that AGN is:

- *"bound by, the Gas Interface Protocol in respect of the provision of information, giving of notice, delivery of notices or documents and making of requests, and the receipt of information, notice, notices, documents or requests, as contemplated by these Procedures.";* and
- "*any failure to use the FRC HUB in accordance with the FRC HUB Operational Terms and Conditions may result in AGN being issued a breach notice*."

If the breach is found by AEMO to be material, it must be referred to the AER under section 91B of the NGL. This provision in the NGL is a civil penalty provision, which means that the AER can issue an infringement notice[13] and/or **institute civil proceedings** in the Federal Court and seek an injunction or an order that AGN remedy the breach; and/or an order that a penalty be paid.[14]

In addition, Participant Build Pack 3 - FRC B2B System Architecture Section 6, specifically addresses security noting *"An Internet based message service, by its very nature, presents certain security risks… Beyond the requirements herein, participants should make themselves familiar with these risks and institute countermeasures balanced against an assessment of the inherent risks and the value of the asset(s) that might be placed at risk."*

As a prudent operator, AGN has undertaken appropriate risk assessments of the criticality of its IT systems and considers the maintenance of systems to current version minus one to be the most efficient and effective means of ensuring continued compliance with the wholesale market requirements.

1.4. Risk Assessment

AGN's core applications are reliant on each other to allow high volumes of transactions to flow from one IT system to another and any system failure would have a significant impact across all network operations for an extended period of time while the remediation work was completed. If the upgrades are not implemented, the risk of catastrophic failure increases year-on-year, and if this extends beyond the next AA period, the risk will increase from High to 'Extreme'. Additionally, not implementing timely upgrades makes applications more vulnerable to cyber-attacks and increases the likelihood of security breaches. Security breaches compromise the confidentiality and integrity of corporate and customer data, and availability of operational and corporate systems giving rise to risks across most of the risk categories described below.

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12 AEMO, "*Retail Market Procedures (Victoria)*", Document No: PROJECT-57-30 Version No: 10.0, 14 Sep 2015, http://www.aemo.com.au/Gas/Policies-and-Procedures/Retail-Gas-Market-Procedures/Victoria

13 The maximum infringement notice is $4,000 for individuals ($20,000 for body corporates).

14 The maximum civil penalty is $20,000 for individuals ($100,000 for body corporates), plus $2,000 ($10,000) for every day it continues.

As IT systems age, it becomes increasingly difficult to address security weaknesses and implement the remedial actions required to resolve a system failure. In a worst-case scenario, the application or technology platform may have a catastrophic failure and cannot be recovered, resulting in an urgent need to implement either an upgrade or replacement of that system to restore network operations. The security, safety, operational, customer, reputation, compliance and financial risk consequences summarised below and detailed in Appendix A would be realised and magnified unnecessarily because reactive remedial actions take significant time and cost to implement. Furthermore, AGN's management and staff would be under pressure to recover functionality quickly, thereby increasing the risk of error.

The planned upgrades are required to, among other things; manage the transition of one version of the technology to a subsequent improved version. Upgrade versions are provided by vendors who recommend that their technology be upgraded to ensure continued provision of ongoing support and maintenance and that any known issues including security vulnerabilities are addressed.

If the Applications Renewal does not proceed, then it will give rise to the following risk consequences:

- *Health and Safety* - Failure of the critical IT systems will have adverse effects across the business as the true state of the network will not be known reliably, thereby creating public safety risks; for example, if the Geospatial Information System (GIS) system fails, it could result in the Dial Before You Dig (DBYD) service not providing the latest gas location information to the public. This could result in a significant public safety issue if underground excavation is carried out in an area that AGN had indicated was clear of gas assets, but in fact was not. Furthermore, security breaches may cause outages in operational systems resulting in insufficient safety information being available in real time to field crew and lack of a pictorial representation of the asset, increasing the likelihood of a safety incident.
- *Operational* - Uncorrected deficiencies and poor integration between systems may result in inefficient work order processing, an inability to make spatial and logical queries, an inability to carry out timely repairs and maintenance, longer outages and operational risks of errors in manual data processes compared to electronic communications and confidential information being compromised.
- *Customers* - The Health and Safety and Operational risks will result in slower and inefficient responses to call outs, and longer outages, which may result in breaches of the service standards, set out in the Victorian Gas Distribution System Code. In addition, security breaches may result in confidential customer data being compromised.
- *Reputation* - AGN's reputation could be damaged significantly in the event of health and safety incidents; supply disruptions; delayed repairs and maintenance; compromised corporate, staff and customer information and resultant litigation.
- *Compliance* - Unsupported and poorly integrated systems and compromised customer information may result in AGN not complying with a range of legal and regulatory obligations, for example the RMP, the consequences of which are set out in Section 1.3.2 Box 1.1.
- *Financial* - The Health and Safety, Operational, Customer and Compliance consequences outlined above will result in sizeable additional costs (including potentially Guaranteed Service Level (GSL) payments) and compromised staff and customer data could lead to significant litigation costs. In addition, without the continuation of IT vendor support which requires movement to a recent version of the software, AGN will be forced to find and hire expensive IT specialists with detailed knowledge of the outdated systems' inner workings and the

programming language used. Financial penalties may also be imposed for not complying with RMP or other regulatory obligations.

A summary of the risk assessment is provided in the Table 1.3. As this table shows, the untreated risk has been rated as 'High' because the operational and financial related risks are high. The full risk assessment results are included as Appendix A to this business case.

Table 1.3: Risk Rating

Risk Area	Untreated Risk Level
Health and Safety	Moderate
Environment	Negligible
Operational	High
Customers	Moderate
Reputation	Moderate
Compliance	Moderate
Financial	High
Untreated Risk Rating	**High**

1.5. Options Considered

AGN has identified the following options to address the risks outlined in Section 1.4 and support AGN's business objectives:

- Option 1: Do Nothing; or
- Option 2: Upgrade critical IT applications on a regular basis consistent with good industry practice and AGN's application lifecycle management methodology.

1.5.1. Option 1 – Do Nothing

Option 1 is not considered feasible due to the significant increase in risk associated with not upgrading the applications. Specifically, if AGN's critical business IT applications are not upgraded, the following issues will arise:

- core applications will no longer be supported by IT vendors;
- failure in older applications may occur, resulting in lengthy and unplanned network outages;
- applications will become unstable and vulnerable to security breaches, which would put the safety of network services at considerable risk and may allow staff and customer data to be compromised;
- AGN will not be compliant with a range of legal and regulatory obligations for example, the RMP if there is a failure of key IT systems;

- the IT systems will be unable to support AGN's strategic objectives, particularly in regard to the national alignment of IT systems;
- technology upgrades for core software will be required, so not continuing with the planned upgrades will mean the opportunity for the 'change out' of inefficient/obsolete technologies will be missed; and
- staying with existing systems as software license renewals become due will lock AGN into old technology and another full license payment for the duration of the of the license agreement period. Furthermore, the costs of maintenance and support agreements will increase as the systems are not upgraded and therefore placed out of the prescribed vendor maintenance cycle.

The risks associated with Option 1 are shown in Appendix A as the 'Risk Untreated' and summarised in Section 1.4. Option 1 would expose AGN to a 'High' risk during the next AA period, and the risk would likely to increase to 'Extreme' in the subsequent AA period.

1.5.1.1. Cost/Benefit Analysis

The benefit of this option is that no upfront capital investment is required. While there are no upfront capital costs, the high operational risks associated with this option are likely to result in significantly higher operational costs over the next AA period if IT systems become unstable, fail or are subject to security breaches.

The Do Nothing option also gives rise to Health and Safety, Customer, Reputation, Compliance and Financial risks, which, as noted in Section 1.4, are rated 'Moderate' to 'High', with the overall untreated risk being 'High' and potentially rising to 'Extreme' in the subsequent AA period. Based on this risk assessment, it is imperative the systems are on an upgrade path as discussed in Option 2. 'Do Nothing' is not therefore considered a feasible option.

1.5.2. Option 2 – Upgrade critical IT applications in the next AA period

Option 2 involves a regular upgrade of critical IT applications in accordance with good industry practice and AGN's application lifecycle management methodology (i.e. every two years for most of the applications).

1.5.2.1. Cost/Benefit Analysis

The cost of implementing Option 2 is $22,041.1 ($000, 2016) over the next AA period, as detailed in Section 1.7.3.2 of this business case.

The key benefit of this option is that the security and integrity of the IT environment will be maintained via a prudent cycle of application upgrades. The level of risk associated with system(s) failure, the integration between systems not operating as required and the risk of staff and customer data being compromised will therefore be substantially reduced and security risks addressed, thereby reducing the overall risk rating from 'High' to 'Moderate' (see Appendix A).[15]

Reducing these risks is of considerable importance given that:

- failure of the critical IT systems will have adverse effects across the business as the true state of the network will not be known reliably, thereby creating public safety and operational risks.

[15] While the consequence of an event occurring remains the same as in Option 1, the likelihood of the event happening over the next AA period is reduced to 'Unlikely' due to the ongoing stay-in-business 2 year cycle of upgrades. This reduces the overall risk level to 'Moderate', which is considered to be consistent with good industry practice.

For example, if the GIS system fails, it could result in the DBYD service not providing the latest gas location information to the public. This could result in a significant public safety issue if underground excavation is carried out in an area that AGN had indicated was clear of gas assets, but in fact was not;

- critical IT applications are linked together and are reliant on each other to allow high volumes of transactions to flow from one system to another. For example, a failure in the Customer Care and Billing application will impact the Maximo application resulting in public leak reports or requests to turn meters on or off needing to be manually entered into Maximo rather than being electronically transferred. This would delay the information getting to the operators in the field to do the work and significantly increase the risk of non-compliance with the RMP and the service standards set out in the Victorian Gas Distribution System Code (which could require the payment of a GSL payment);
- the full functionality of these linked critical IT application systems is necessary to satisfy the RMP and a range of other regulatory obligations, and more generally, AGN's operating requirements; and
- significant IT investment has been made in recent years to ensure that AGN's application systems meet their obligations as set out in the RMP. This investment requires AGN to implement an upgrade strategy that is consistent with good industry practice.

Other benefits of upgrading critical IT applications include:

- ensuring upgraded applications continue to provide required integrated functionality to support business processes;
- managing alignment with other co-existing applications, including in other states where AGN operates;
- ensuring validity of support requirements with technology vendors;
- maintained systems security with critical security upgrades applied thereby protecting information assets from confidentiality, integrity and availability risks;
- introduction of new functionality in a timely manner;
- improvement to software performance, efficiency and stability of IT systems over time;
- providing for the continuation of IT vendor support (this requires movement to a recent version of the software);
- improving the security and integrity of business information as vendors place greater emphasis on these solutions; and
- ensuring compliance to market requirements for the latest IT systems.

The risks associated with Option 2 are shown in Appendix A as 'Residual Risk'. While the consequence of an event occurring remains the same as in Option 1, the likelihood of the event happening over the next AA period is reduced to 'Unlikely' due to the ongoing stay-in-business two year cycle of upgrades. This reduces the overall risk level to 'Moderate', which is considered to be consistent with good industry practice.

1.6. Summary of Cost/Benefit Analysis

The summary of costs, benefits and risks of the option considered in this business case in provided below.

Table 1.4: Summary of Cost/Benefit Analysis

Option	Benefits	Costs/Risks
Option 1	No upfront capital investment is required.	High operational risks, which will result in significantly higher costs over the longer run if IT systems become unstable, fail or are subject to security breaches. The Do Nothing option also gives rise to Health and Safety, Customer, Reputation, Compliance and Financial risks, which, as noted in Section 1.4, are rated 'Moderate' to 'High', with the overall untreated risk being 'High'.
Option 2	The key benefits of Option 2 are as follows: • substantially reduces the level of risk of system(s) failing or the integration between systems not operating as intended; • maintains systems security, protecting information assets from confidentiality, integrity and availability risks; • provides for the continuation of IT vendor support (this requires movement to a recent version of the software); and • provides for compliance with the latest IT systems with market requirements.	$22,041.1 ($000, 2016) capex. The level of risk of system(s) failure or the integration between systems not operating as required is reduced substantially and security risks are addressed thereby reducing the overall risk rating from 'High' to a residual risk of 'Moderate'.

1.7. Proposed Solution

1.7.1. What is the Proposed Solution?

The proposed solution is Option 2, which will involve systematically upgrading the software and applications outlined in the Applications Upgrade Plan, summarised in Table 1.5, to ensure that AGN can continue to maintain reliable, secure, compliant and efficient business processes and systems and preserve the ongoing integrity of the services. These upgrades are required to manage the transition of one version of the technology to a subsequent improved version of the technology, correct defects in the technology (which includes how a technology type interacts with other technology types) and attend to security concerns. Upgrade versions are provided by vendors who recommend that their technology be upgraded to ensure ongoing support and maintenance contracts and that any known issues including security vulnerabilities are addressed.

Generally an application upgrade will involve not only the application upgrade itself, but also upgrades to the underlying associated technology platform components, assessment, design and implementation of any changes to configuration, customisations and integrations associated with the upgrades and complete testing of all impacted end-to-end processes.

Software application assets are usually upgraded on a two year cycle[16] depending on the assets and the policies of the vendors for the frequency of upgrades. The application of version upgrades to critical business systems every two years is good industry practice as vendors typically provide at least one major and several minor upgrades or patches over that period. There exist interdependencies between the various software applications, which are integrated to support business requirements. This interdependency creates a working construct of software applications,

[16] Mobility technology upgrades have been identified as an exception to the applied 2 year cycle of application upgrades. The rapid change in technology cycle and the ongoing speed of mobility based change indicates that a yearly upgrade cycle for Mobility is a prudent approach in this area.

and associated technology platform components, that are at risk if they are not maintained at compatible software release levels as prescribed by technology vendors. The interoperability of disparate applications must be constantly monitored in order to have visibility of potential incompatibilities. The application of version upgrades through a quality based testing regime mitigates any risks associated with this issue.

To ensure that the IT application systems are kept stable, secure and at optimum performance, AGN utilises an application lifecycle management methodology to determine upgrade timelines and priorities, which is outlined in Appendix C. The Application Upgrade Plan outlined above is in place as a stay in business program of work that ensures compliance with an underlying principle of staying at a minimum of N-1[17] for application upgrades. The alignment with industry practice of N-1 ensures ongoing vendor support and mitigates the risk of security breaches, system outages and potential regulatory non-compliance.

This enables appropriate levels of operation, data integrity and inter-operability between various vendor provided technologies. This application roadmap is used to identify and prioritise upgrades, and has been used as the basis for the development of the Applications Upgrade Plan, which sets out the applications and the frequency of upgrades that AGN proposes to carry out in the next AA period, which is summarised in Table 1.5.

Table 1.5: Application Upgrade Plan

Renewal Projects	2018	2019	2020	2021	2022
Billing Estimation Model	X		X		X
Dial Before You Dig		X		X	
Metering & Billing System	X		X		X
Enterprise Asset Management	X		X		X
Geospatial Information System					X
Telemetry System		X		X	
Historian System		X		X	
FRC Market Gateway		X		X	
Middleware – BizTalk		X		X	
Field Data / Mobility	X	X	X	X	X

[17] N-1 Refers to the specific software version number, which is associated with a specific vendor software. Where "N" representing the current version of the released and supported software, whereas -1 would refer to an older version of the same vendor software which would still be supported. Upgrade versions are provided by vendors who recommend that their technology be upgraded to ensure ongoing support and maintenance contracts.

1.7.2. Why are we Proposing this Solution?

Option 2 is being proposed because it is the most cost effective way of dealing with the risks posed by outdated and unsupported applications. It is also consistent with good industry practice.

In this regard it is worth noting that AGN cannot adopt the strategy of doing nothing as the IT applications are integral to providing the services and the increased risk of system failure and the related impacts are unacceptable. The proposed solution mitigates the high risks associated with the 'Do Nothing' option, by ensuring the security and integrity of the IT environment via a prudent cycle of application upgrades.

1.7.3. Forecast Cost Breakdown

1.7.3.1. Methodology and approach

Because the Applications Renewal is a national project, the total project cost is estimated based on the work that needs to be carried out across all Australian jurisdictions that AGN operates in. The total project cost is then allocated to state-specific AGN networks based on the customer numbers across each of the networks, to ensure that the cost allocations used reflect how AGN ultimately allocates costs to customers served from these networks. As at 31 December 2015, Victoria and Albury accounted for 51.35% and 1.79% of AGN's total customer numbers, respectively.

The approach that AGN has used to estimate the total project cost and its proposed approach to carrying out the work is based on the same approach used in the South Australian business case SA57 "Applications Renewal" project for the FY2016/17 to FY2020/21 AA period, which has been approved by the AER in its Final Decision and is outlined below:

- AGN utilises an industry standard Business and Technology (B&T) Project Methodology, which is managed through formal governance. This B&T Project Methodology divides the projects into key stages – concept, develop, plan, deliver and close. Each stage consists of key tasks and activities to ensure the consistency and standardisation across projects. The project methodology is outlined in Appendix C.
- To ensure project estimates are developed in a consistent manner, AGN utilises an Estimation Tool, which is aligned with the B&T Project Methodology. This estimation tool has been used to forecast the work and cost estimates for the application upgrade program of work. This estimation tool utilises historic figures from the current AA period for resource work effort estimates. All historic figures are sanity checked to ensure any changes to the way historical projects were carried out were taken into account. The work effort estimates are based on a complexity matrix tool, which uses a series of questions to categorise projects into simple, medium and complex.
- The material and direct labour costs, and applicable planning, design and commissioning charges, are based on historic actual costs of similar projects and on vendor quotes subject to a competitive tendering process in accordance with the APA Procurement Policy and guidelines[18]. Resource Unit Costs (both internal and external) are based on research, where actual placement costs have been used based on historical project resources and current resourcing rates (2016).

[18] Available upon request.

- The historic figures and work effort estimates are used as inputs into the final estimates, which are subject to stringent review and endorsement by members of the IT Estimates Review Committee. The work effort, cost and timing of projects are monitored throughout the project lifecycle to ensure on time and on budget delivery.
- When implementing the project, AGN will use a formalised Project Methodology and utilise a combination of internal and external resources to deliver the program of work. The Project Methodology is outlined in Appendix C and provides a consistent, standard and quality assured project implementation framework, ensuring that the work is carried out in a prudent and efficient manner.

1.7.3.2. Forecast Summary Costs

The costs that are forecast to be incurred over the next AA period and cost breakdowns by individual upgrade project, cost category and between Victoria and Albury Networks are provided in Tables 1.6 to 1.9. These costs were estimated using a 'bottom-up' standard IT cost model and the approach outlined above. These costs have also been reviewed and endorsed by members of the IT Estimates Review Committee. The detailed cost breakdown by individual project is provided in Appendix B.

Before examining these tables, it is worth noting the following:

In addition to upgrades to the existing suite of application systems, the forecast capex includes the cost of software licence growth, which is estimated to be approximately 5% per license unit (real average annual increase). This forecast is based on the following drivers and metrics:

- Software and technical licensing for the metering and billing system has a one to one relationship with customer connections, which is forecast to increase over the next AA period.
- The number of internal users is the most common mechanism used by software application vendors for charging of licenses. For the next AA period internal user growth is expected to be 2.5% per year.
- The remaining software is generally licensed by services or central processing unit (CPU) usage. The growth requirement in this area for the next AA period is expected to be 5% per year.

Table 1.6: Capex/Opex Split

	2018	2019	2020	2021	2022	Total
Capex	4,637.1	3,366.6	4,655.7	3,388.0	5,993.7	**22,041.1**
Opex	-	-	-	-	-	**-**
Total	**4,637.1**	**3,366.6**	**4,655.7**	**3,388.0**	**5,993.7**	**22,041.1**

Table 1.7: Project Cost Estimate, by application ($000, 2016)

Applications renewal projects	2018	2019	2020	2021	2022	Total
Billing Estimation Model	313.4	-	313.4	-	313.4	**940.1**
Dial Before You Dig	-	348.4	-	348.4	-	**696.8**
Metering & Billing System	2,016.3	-	2,016.3	-	2,016.3	**6,048.9**
Enterprise Asset Management	1,905.9	-	1,905.9	-	1,905.9	**5,717.7**
Geospatial Information System	-	-	-	-	1,314.8	**1,314.8**
Telemetry System	-	991.8	-	991.8	-	**1,983.7**
Historian System	-	908.4	-	908.4	-	**1,816.8**
FRC Market Gateway	-	304.1	-	304.1	-	**608.1**
Middleware – BizTalk	-	404.0	-	404.0	-	**808.0**
Field Data / Mobility	259.3	259.3	259.3	259.3	259.3	**1296.5**
License Growth	142.2	150.6	160.9	172.0	184.0	**809.7**
Total	**4,637.1**	**3,366.6**	**4,655.7**	**3,388.0**	**5,993.7**	**22,041.1**

Table 1.8: Project Cost Estimate, by cost ($000, 2016)

	2018	2019	2020	2021	2022	Total
Direct Labour	1,215.5	535.8	1,215.5	535.8	1,304.9	**4,807.6**
Contracted Labour	3,106.8	2,541.8	3,106.8	2,541.8	4,124.6	**15,421.9**
Hardware, Software and Maintenance	149.6	230.1	168.2	251.5	342.2	**1,141.7**
Travel, Sundry, Other	165.1	58.9	165.1	58.9	222.0	**669.9**
Total	**4,637.1**	**3,366.6**	**4,655.7**	**3,388.0**	**5,993.7**	**22,041.1**

Table 1.9: Capex split between Victoria and Albury ($000, 2016)

	2018	2019	2020	2021	2022	Total
Capex – Victoria	4,480.9	3,253.2	4,498.9	3,273.9	5,791.8	**21,298.6**
Capex - Albury	156.2	113.4	156.8	114.1	201.9	**742.4**
Total	**4,637.1**	**3,366.6**	**4,655.7**	**3,388.0**	**5,993.7**	**22,041.1**

1.7.4. Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN considers the forecast capex for this project to be:

- *Prudent* – The expenditure is necessary in order to maintain the safety and integrity of services and comply with regulatory obligations and requirements and is of a nature that a prudent service provider would incur.
- *Efficient* – The Applications Renewal project will enable AGN to maintain its operational efficiency and address the high risks of non-compliance with the RMP and other relevant regulations and legislation, potential customer and business interruptions and corresponding adverse financial and reputation impacts. Additionally, the manner in which AGN intends to carry out the upgrade (i.e. by using a combination of internal and external resources to deliver the program of work and using the Project Management Office to provide guidance and governance to the project) is consistent with good industry practices and can be considered efficient. The expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.
- *Consistent with accepted good industry practice* – The Applications Renewal project will ensure that AGN continues to operate in line with good industry practice, in terms of having all critical systems up to date, secure and supported by vendors.
- *Achieves the lowest sustainable cost of delivering pipeline services* – The Applications Renewal project is necessary to mitigate the risks associated with operating on older versions of the software with the resultant performance, data integrity and cost implications should these systems fail and is therefore consistent with the objective of achieving the lowest sustainable cost of service delivery.

The capex can therefore be viewed as being consistent with rule 79(1)(a) of the NGR.

The proposed capex is also consistent with rule 79(1)(b), because the expenditure is necessary to:

- *maintain and improve the safety of services (rule 79(2)(c)(i))* - the safety of services will be adversely affected if any of the critical IT systems fails or if there is a security breach;
- *maintain the integrity of services (rule 79(2)(c)(ii))* - the integrity of the services will be adversely affected if critical systems are unavailable; and
- *comply with a regulatory obligation or requirement (rule 79(2)(c)(iii))* - regulatory obligations (e.g. RMP requirements for processing timeframes) will be breached if key systems are not available or customer data are compromised.

Appendix A – Risk Assessment

The risk assessments below demonstrate the change in risk profile associated with the two options considered in this business case. As noted in Section 1.4, if the periodic upgrades to the AGN's critical IT applications are not implemented, the risk of catastrophic failure increases year-on-year, and is assessed as 'High' during the next AA period. Moreover, if this situation extends beyond the next AA period, the risk will increase to 'Extreme'.

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Option Risk
Risk Untreated Option 1	**Likelihood**	*Possible*	*Unlikely*	*Occasional*	*Possible*	*Possible*	*Possible*	*Possible*	**HIGH**
	Consequence	*Medium*	*Insignificant*	*Significant*	*Medium*	*Medium*	*Medium*	*Significant*	
	Risk Level	*Moderate*	*Negligible*	*High*	*Moderate*	*Moderate*	*Moderate*	*High*	
Residual Risk Option 2	**Likelihood**	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	**MODERATE**
	Consequence	*Medium*	*Insignificant*	*Significant*	*Medium*	*Medium*	*Minor*	*Significant*	
	Risk Level	*Moderate*	*Negligible*	*Moderate*	*Moderate*	*Moderate*	*Low*	*Moderate*	

Appendix B – Detailed Cost Breakdown

The tables below set out the costs of upgrading the core AGN IT applications. The costs in these tables are the Victorian and Albury share of the costs for a single upgrade only and are expressed in real 2016 values.

Billing Estimation Model

IT & ICT Procurement Estimations Template: B&T Projects			
Project Name:	Billing Estimation Model		
Project Complexity:	Simple		
Project Type:	Upgrade		
Estimations Summary			
Total Project (end to end)	Effort (Days)	Total Cost	
End to End Total	266	$ 313,364.03	
Estimations by Project Stage			
		Stage Cost	
Develop Stage Total	61	$ 71,604.83	
Plan Stage Total	67	$ 73,813.31	
Deliver Stage Total	123	$ 148,784.89	
Close Stage Total	15	$ 19,160.99	

Dial Before You Dig

IT & ICT Procurement Estimations Template: B&T Projects			
Project Name:	Dial Before You Dig		
Project Complexity:	Medium		
Project Type:	Upgrade		
Estimations Summary			
Total Project (end to end)	Effort (Days)	Total Cost	
End to End Total	284	$ 348,398.97	
Estimations by Project Stage			
		Stage Cost	
Develop Stage Total	81	$ 129,314.46	
Plan Stage Total	81	$ 93,839.90	
Deliver Stage Total	109	$ 111,434.88	
Close Stage Total	12	$ 13,809.73	

Metering & Billing System

IT & ICT Procurement Estimations Template: B&T Projects			
Project Name:	Metering & Billing System		
Project Complexity:	Complex		
Project Type:	Upgrade		
Estimations Summary			
Total Project (end to end)	Effort (Days)	Total Cost	
End to End Total	1,473	$ 2,016,293.42	
Estimations by Project Stage			
		Stage Cost	
Develop Stage Total	366	$ 462,585.45	
Plan Stage Total	500	$ 680,769.59	
Deliver Stage Total	554	$ 800,619.46	
Close Stage Total	53	$ 72,318.92	

Enterprise Asset Management

IT & ICT Procurement Estimations Template: B&T Projects			
Project Name:	Enterprise Asset Management		
Project Complexity:	Complex		
Project Type:	Upgrade		
Estimations Summary			
Total Project (end to end)	Effort (Days)	Total Cost	
End to End Total	1210	$ 1,905,899.44	
Estimations by Project Stage			
		Stage Cost	
Develop Stage Total	263	$ 332,228.22	
Plan Stage Total	446	$ 589,504.73	
Deliver Stage Total	462	$ 939,674.00	
Close Stage Total	39	$ 44,492.49	

Geospatial Information System

IT & ICT Procurement Estimations Template: B&T Projects			
Project Name:	Geospatial Information System		
Project Complexity:	Complex		
Project Type:	Upgrade		
Estimations Summary			
Total Project (end to end)	Effort (Days)	Total Cost	
End to End Total	1000	$ 1,314,780.62	
Estimations by Project Stage			
		Stage Cost	
Develop Stage Total	227	$ 417,497.74	
Plan Stage Total	299	$ 362,384.21	
Deliver Stage Total	431	$ 488,079.73	
Close Stage Total	43	$ 46,818.94	

Telemetry System

IT & ICT Procurement Estimations Template: B&T Projects			
Project Name:	Telemetry System		
Project Complexity:	Medium		
Project Type:	Upgrade		
Estimations Summary			
Total Project (end to end)	Effort (Days)	Total Cost	
End to End Total	832	$ 991,844.42	
Estimations by Project Stage			
		Stage Cost	
Develop Stage Total	208	$ 241,623.63	
Plan Stage Total	207	$ 258,357.98	
Deliver Stage Total	363	$ 434,011.82	
Close Stage Total	53	$ 57,850.99	

Historian System

IT & ICT Procurement Estimations Template: B&T Projects		
Project Name:	Historian System	
Project Complexity:	Medium	
Project Type:	Upgrade	
Estimations Summary		
Total Project (end to end)	Effort (Days)	Total Cost
End to End Total	863	$ 908,410.66
Estimations by Project Stage		
		Stage Cost
Develop Stage Total	239	$ 241,339.03
Plan Stage Total	265	$ 319,603.46
Deliver Stage Total	345	$ 331,841.17
Close Stage Total	14	$ 15,627.01

FRC Market Gateway

IT & ICT Procurement Estimations Template: B&T Projects		
Project Name:	FRC Market Gateway	
Project Complexity:	Simple	
Project Type:	Upgrade	
Estimations Summary		
Total Project (end to end)	Effort (Days)	Total Cost
End to End Total	353	$ 304,052.77
Estimations by Project Stage		
		Stage Cost
Develop Stage Total	76	$ 79,260.52
Plan Stage Total	83	$ 90,701.35
Deliver Stage Total	180	$ 118,463.88
Close Stage Total	14	$ 15,627.01

Middleware – BizTalk

IT & ICT Procurement Estimations Template: B&T Projects		
Project Name:	Middleware - BizTalk	
Project Complexity:	Medium	
Project Type:	Upgrade	
Estimations Summary		
Total Project (end to end)	Effort (Days)	Total Cost
End to End Total	303	$ 404,015.20
Estimations by Project Stage		
		Stage Cost
Develop Stage Total	62	$ 109,399.44
Plan Stage Total	76	$ 88,908.39
Deliver Stage Total	152	$ 191,591.31
Close Stage Total	13	$ 14,116.06

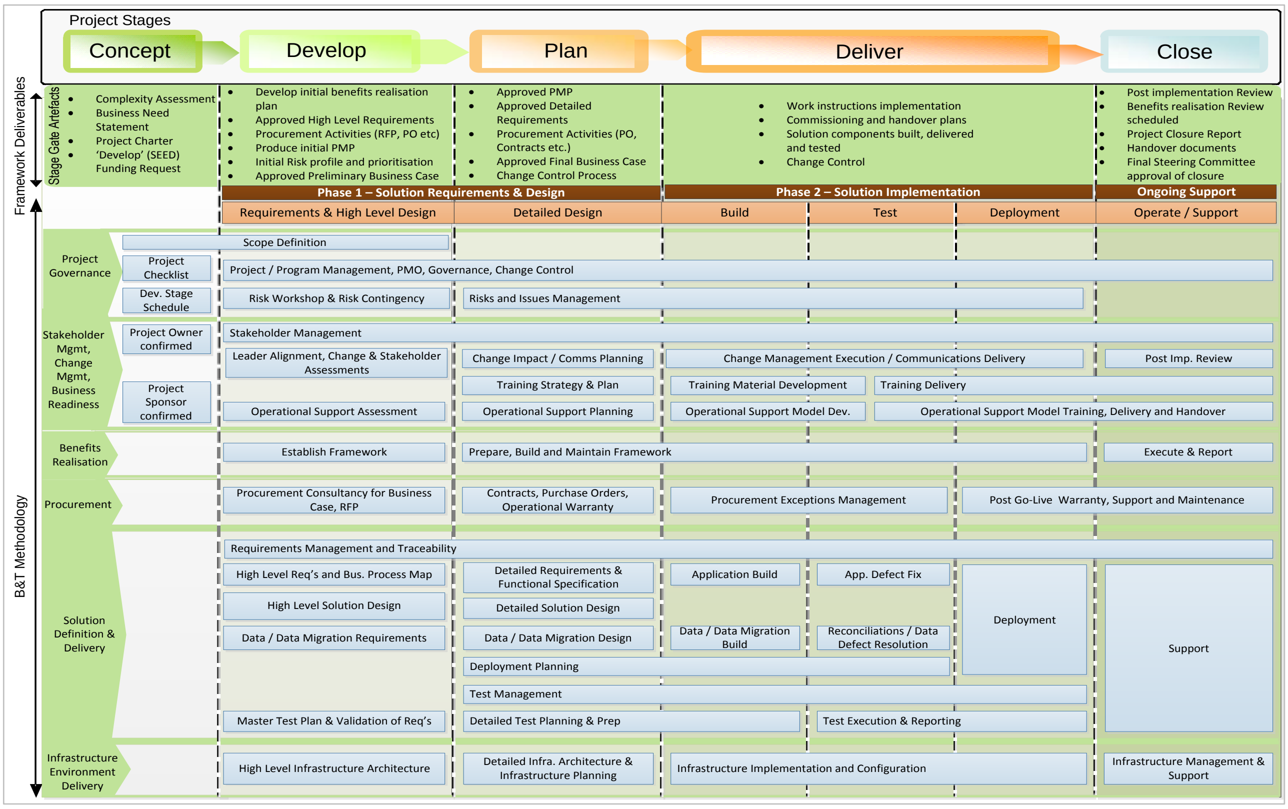
Field Data / Mobility Systems

IT & ICT Procurement Estimations Template: B&T Projects		
Project Name:	Field Data / Mobility Systems	
Project Complexity:	Simple	
Project Type:	Upgrade	
Estimations Summary		
Total Project (end to end)	Effort (Days)	Total Cost
End to End Total	219	$ 259,294.57
Estimations by Project Stage		
		Stage Cost
Develop Stage Total	60	$ 49,747.72
Plan Stage Total	56	$ 67,961.98
Deliver Stage Total	95	$ 132,394.95
Close Stage Total	9	$ 9,189.93

Appendix C - Methodologies

AGN Project Methodology

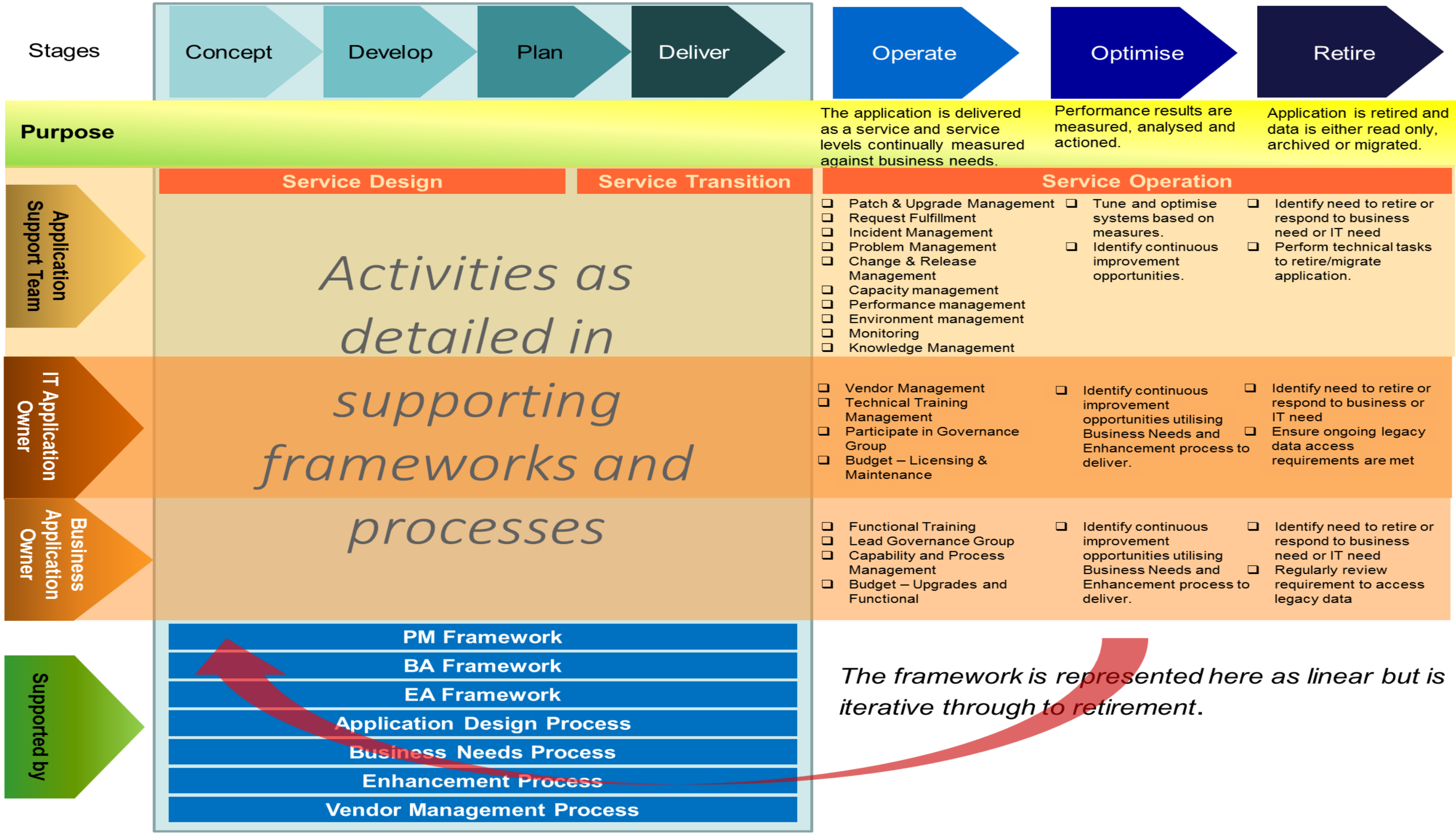
To manage all its IT projects, AGN utilises an industry standard Business and Technology (B&T) Project Methodology, which is managed through formal governance. The key aspects of this methodology are outlined in the diagram below.



AGN Application Lifecycle Management

AGN utilises an industry-standard application lifecycle management methodology and a practical framework to determine upgrade timelines and priorities. The diagram below outlines the key aspects of this framework.

Application Lifecycle Management Framework



Business Case – Capex V47

Business Intelligence

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	Peter Butler, *Manager Network Support Services*, APA Group
Approved By	John Ferguson, *Group Executive Networks,* APA Group

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	Australia Gas Networks Limited's (AGN) existing reporting, information management and decision making systems are disparate, difficult to access, costly to operate, inefficient and limiting AGN's ability to make informed and efficient decisions, drive further efficiencies, comply with regulatory obligations and make a range of other improvements to customer service delivery, the safety and integrity of services and comply with regulatory obligations. The Business Intelligence project involves the implementation of a Business Intelligence Toolset that will be integrated into other AGN enterprise business applications. The overarching objectives of this project are to: • enable consolidated views of data from multiple IT systems for improved data analysis, reporting and decision-making; • improve data quality and integrity; • streamline reporting; and • allow for greater access to information to enable more informed and efficient decisions to be made throughout the business. The Business Intelligence project is also expected to result in the implementation of more efficient end-to-end business processes and improvements in customer service, safety and integrity of services and compliance with regulatory obligations. The proposed project forms part of AGN's Enterprise Information Management Strategy and Roadmap, the South Australian component of which has recently been approved by the Australian Energy Regulator (AER) in its Final Decision on AGN's South Australian Access Arrangement (AA) for the 2016/17 to 2020/21 AA period. In approving this project, the AER noted that it was satisfied that the proposed expenditure *"is justifiable under rule 79(2)(a)"* and that "*this capex would be incurred by a prudent service provider acting efficiently and that it is conforming capex under rule 79*"[1] of the National Gas Rules (NGR).
Economic Value of Business Intelligence	The Business Intelligence project will yield a number of tangible and intangible benefits, with the tangible benefits including a range of avoided costs and cost savings (e.g. from not having to employ as many staff to validate and analyse data). The intangible

[1] AER, *"Final Decision: Australian Gas Networks Access Arrangement 2016 to 2021, Attachment 6 – Capital expenditure",* May 2016, pg. 6-35.

Project	benefits, on the other hand, include the safety, customer service, information management, data quality and integrity benefits outlined above. The tangible benefits alone are expected to reach $14,965.7 ($000, 2016) over the first 10 years of the project's life, while the cost of implementing and maintaining the Business Intelligence solution over the same period is $11,828.2 ($000, 2016). The excess of benefits over costs of $3,137.5, gives rise to a positive Net Present Value (NPV) of $1,196 ($000, 2016)[2]. If the intangible benefits could be quantified, then the NPV would be even greater. As this analysis highlights, implementing the Business Intelligence project in the Victorian and Albury networks will yield a positive net economic value, the beneficiaries of which will be customers in these networks.
Estimated Cost	The proposed cost of the project over the next (2018 to 2022) AA period is $11,078.2 ($000, 2016) capital expenditure (capex).

Consistency with the National Gas Rules (NGR)	The Business Intelligence project complies with the new capex criteria in rule 79 of the NGR because:
	• 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)); and
	• it is justified under rule 79(2)(a) and (c), because:
	  • the overall economic value of the capex is positive (rule 79(2)(a)); and
	  • the expenditure is also necessary to:
	    ○ *Maintain and improve the safety of services (rule 79(2)(c)(i))* - More extensive access to accurate information about assets and the ability to predict failures will result in a safer network.
	    ○ *Maintain the integrity of services (rule 79(2)(c)(ii))* - The integrity of services will be preserved and improved through rapid and accurate access to asset information.
	    ○ *Comply with a regulatory obligation or requirement (rule 79(2)(c)(iii))* - Access to more extensive and accurate asset information will decrease the time required to meet regulatory reporting periods. The project will also enable AGN to optimise the existing risk-based approaches to asset management that are a key focus of the ESV.

Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Safety, Reliability and Customer Service themes as its implementation will allow AGN to continue to maintain the safety of the network, whilst continuing to provide a highly reliable supply of natural gas to AGN's customers and enabling further improvements in customer service (e.g. by enabling AGN to provide real time responses to queries). More information detailing the results of AGN's stakeholder engagement program is provided in Chapter 5 of the Access Arrangement Information document.
Supporting Information	• V47 Supporting Information 1 (NPV & Options Analysis) • V47 Supporting Information 2 (ESV GPI Safety Management Report Executive Briefing) • V47 Supporting Information 3 (ESV GPI Safety Management Report 2014-2015 Non-licensed Gas Infrastructure)

2 A discount rate of 3.98%, which is AGN's proposed real pre-tax Weighted Average Cost of Capital (WACC), has been used to calculate NPV.

1.3. Background

Australian Gas Networks Limited (AGN) maintains and operates a number of critical Information Technology (IT) systems that are integral to the efficient and effective management of the Victorian and Albury networks and are required to meet a range of legal and regulatory obligations, including those prescribed in the:

- National Gas Law (NGL) and National Gas Rules (NGR);
- Victorian Gas Distribution System Code[3];
- Victorian *Gas Industry Act 2001*[4]; and
- Victorian Retail Market Procedures[5] (Retail Market Procedures).

These obligations predominantly relate to safely and effectively managing a gas distribution network, ensuring accuracy and timeliness of retail market transactions and delivering against prescribed customer service levels.

They are also required to meet Energy Safe Victoria's (ESV's) gas and pipeline safety requirements[6].

As a prudent operator, AGN has ongoing maintenance plans for its critical IT systems, which are based on the appropriate risk assessments, to ensure continued compliance with these legal, regulatory and safety obligations.

1.3.1. AGN's IT Environment

Given the highly integrated nature of AGN's IT environment, upgrades and improvements to these systems have been incorporated into a detailed *Information Technology Investment Plan*[7] (IT Plan), which has been provided as Attachment 8.5 to AGN's Access Arrangement Information (AAI) document.

This IT Plan details the proposed IT capital program of work over the next AA period, as well as acting to support AGN's business objectives, which, in turn, are aligned with the stakeholder expectations identified during the stakeholder engagement program recently undertaken by AGN in Victoria and Albury[8].

In the current AA period, a number of major projects to nationalise and upgrade key IT application systems were implemented. These projects delivered improved IT systems with increased scalability, flexibility and reliability, while also ensuring that AGN continues to meet its obligations under the RMP and other relevant regulatory and customer obligations. The IT systems nationalisation program has so far successfully delivered to Victoria and Albury the Enterprise Asset Management (EAM) system, the National Metering and Billing (MnB) system and other core foundation platforms to leverage efficiencies in business operations through data consolidation, enablement of standard national processes and task automation.

Additional projects to complete the nationalisation program during the next (2018 to 2022) AA period have been included in separate business cases. The completion of the nationalisation program of work is required in order for AGN to realise the full business benefits from moving

3 Essential Services Commission, "*Gas Distribution System Code*", Version 11.0.
4 http://www.austlii.edu.au/au/legis/vic/consol_act/gia2001167/
5 AEMO, http://www.aemo.com.au/Gas/Policies-and-Procedures/Retail-Gas-Market-Procedures/Victoria
6 http://www.esv.vic.gov.au/About-ESV
7 APA, "*Victorian and Albury Networks Information Technology Investment Plan for the 2018 to 2022 Access Arrangement Period*", July 2016
8 Deloitte, "*Australian Gas Networks Customer Insights Report, Victorian and Albury Stakeholder Engagement Program*", May 2016.

towards the national enterprise structure and the integrated suite of systems, including enhanced EAM capability, streamlined and scaled applications and processes, and improved risk mitigation. The ultimate beneficiaries of these improvements will be AGN's customers, who will benefit from improved services and lower cost provision of services.

This business case focuses on the Business Intelligence project. The remainder of this business case outlines the rationale for the Business Intelligence project, the objectives, scope and timing of the project, the economic value of the project and the consistency of the project with the NGR. The South Australian component of this project has been recently approved by the AER in its Final Decision on AGN's AA for the 2016/17 to 2021/22 AA period. In approving this project, the AER noted that it is satisfied that the proposed expenditure *"is justifiable under rule 79(2)(a)"* and that "*this capex would be incurred by a prudent service provider acting efficiently and that it is conforming capex under rule 79*"[9] of the NGR.

1.4. Risk Assessment

1.4.1. Deficiencies in the existing information management and reporting systems

AGN's current data analytics, reporting and decision making systems require the consolidation of large amounts of information across a disparate range of applications. Despite the highly integrated nature of AGN's IT applications, the underlying data in these applications is unconnected and siloed. This, in turn, gives rise to:

- manual and inefficient reporting processes, with a substantial amount of manual work required to collate, consolidate, check and disseminate information;
- business risks and inefficiencies because information is fragmented across business lines and systems and manual processes introduce the risk of inaccuracies and duplication of data and information; and
- regulatory compliance risks.
- Apart from being inefficient, the operation of these systems in this manner is exposing AGN to a range of risks as highlighted in Table 1.3, which shows that the untreated risk associated with the current systems is Moderate.

In summary the key risks are:

- *Health and Safety* - Without Business Intelligence tools in place, AGN will be unable to optimise the risk-based approach to asset management, which the ESV is now advocating (see Box 1.1) and to develop additional risk models that can help to reduce the public safety risks inherent in some parts of the network
- *Compliance* - To comply with regulatory and market obligations, significant volumes of data that are currently recorded on paper must be entered manually into various systems such as Maximo, Customer Care & Billing and Oracle Financials, collated manually via paper and entered into various systems. The manual entry of this data gives rise to the adverse consequences of inaccurate data being provided to regulatory and market bodies, which could have implications for others in the market. There is also a potential issue in complying with ESV's safety expectations in optimising the risk based approach to asset management driven by 'effective analysis' (see Box 1.1 over the page for more information).

[9] AER, "*Final Decision: Australian Gas Networks Access Arrangement 2016 to 2021, Attachment 6 – Capital expenditure*", May 2016, pg. 6-35

Table 1.3: Risk Rating

Risk Area	Untreated Risk Level
Health and Safety	Moderate
Environment	Negligible
Operational	Low
Customers	Low
Reputation	Low
Compliance	Moderate
Financial	Low
Untreated Risk Rating	**Moderate**

The operation of these disparate and unconnected systems in this manner is also affecting AGN's ability to:

- make timely and efficient decisions about assets (i.e. maintenance versus replacement), workforce management and other areas of the business because information on what is currently happening within the business is not readily available;
- drive further efficiencies;
- comply with regulatory obligations;
- achieve risk reductions in other areas of the network and make a range of other improvements to the safety and integrity of services;
- optimise AGN's risk-based approach to asset management with existing risk mitigation measures underpinned by additional 'effective analysis' as the ESV is now requiring of Victorian gas distributors (see Box 1.1); and
- improve the level of customer service.

The continued use of disparate and unconnected systems will also mean that AGN's Victorian and Albury networks will fall further behind its peers who have already invested in business intelligence tools (including AGN's South Australian network). The service providers that AGN are aware have already invested in business intelligence solutions (with AER approval), are Energex, Jemena (gas and electricity), Multinet and AusNet Services (electricity)[10]. The AER has also recently approved this expenditure for AGN's South Australian network. [11]

[10] AER, "Draft Decision: JGN Access Arrangement 2015-20", November 2014, Attachment 6, pg-6-39, AER, "Preliminary Decision: Jemena distribution determination 2016 to 2020", October 2015, Attachment 6, pg. 6-94 and AER, "Final Decision: Energex determination 2015-16 to 2019-20", October 2015, Attachment 6, pg. 6-10. AusNet Services, "Electricity Distribution Price Review 2011-2015 Regulatory Proposal", November 2009, pg. 158, Multinet, "Gas Access Arrangement Review January 2013-December 2017 AAI", 30 March 2012, pg. 85

[11] AER, *"Final Decision: Australian Gas Networks Access Arrangement 2016 to 2021, Attachment 6 – Capital expenditure",* May 2016, pg. 6-35.

Box 0.1: ESV's expectations for a risk-based approach to asset management

In the 2014/15 Gas & Pipeline Infrastructure (GPI) Safety Management Report, the ESV noted that it expects Victorian distributors to start employing more of a risk based approach to asset management and that it expects to see:

> *"more evidence that risk-based approaches are being adopted, implemented and sufficiently resourced, and that risk-mitigation requirements are being driven by effective analysis."*[12]

In doing so, the ESV made the following observations:

> *"Pipeline risk is dynamic, increasing as assets age and corrode and as the types of activities in and around pipelines and their easements change."*[13]
>
> *"Empirical evidence also suggests that most high-impact, low-probability incidents occur because of the aligned failures or partial failures of a number of physical and procedural barriers (threat barriers) designed to prevent injury or damage to people, property and the environment, rather than because of an isolated major failure."*[14]
>
> *"In 2013/14, incidents damaging mains and services peaked and there has been no level of improvement to these statistics that demonstrates asset owners are understanding and identifying the root cause of these incidents and sufficiently mitigating the risk to infrastructure and potential harm to people."*[15]
>
> *"Third-party interference and structural failures have the potential to cause high consequence events involving death and significant supply interruption…… the number of hits on mains and services (causing damage and gas escape) remains excessively high."*[16]
>
> *"Proposed land development and third-party works around pipelines need to not only be accurately captured but also competently assessed…"*[17]
>
> *"…safety framework documentation complying with pre-existing standards is no longer acceptable….. an increased emphasis on a risk-based approach to managing and operating assets is now required."*[18]

In order to meet the ESV's increased expectations around the risk-based approach to asset management and operation, accurate data and appropriate data analysis tools are required to optimise effective asset monitoring, analysis and risk management.

1.4.2. Independent review of AGN's current approach to information management and business intelligence

In a review conducted by SMS Management & Technology (SMS) in March 2014, AGN's current approach to information management was found to be immature in terms of being able to transform the data that is collated into information and driving improved business decisions from that information. Specifically, SMS found that:

- Information can be difficult to access.
- Excessive manual work is required to collate, consolidate and disseminate information.

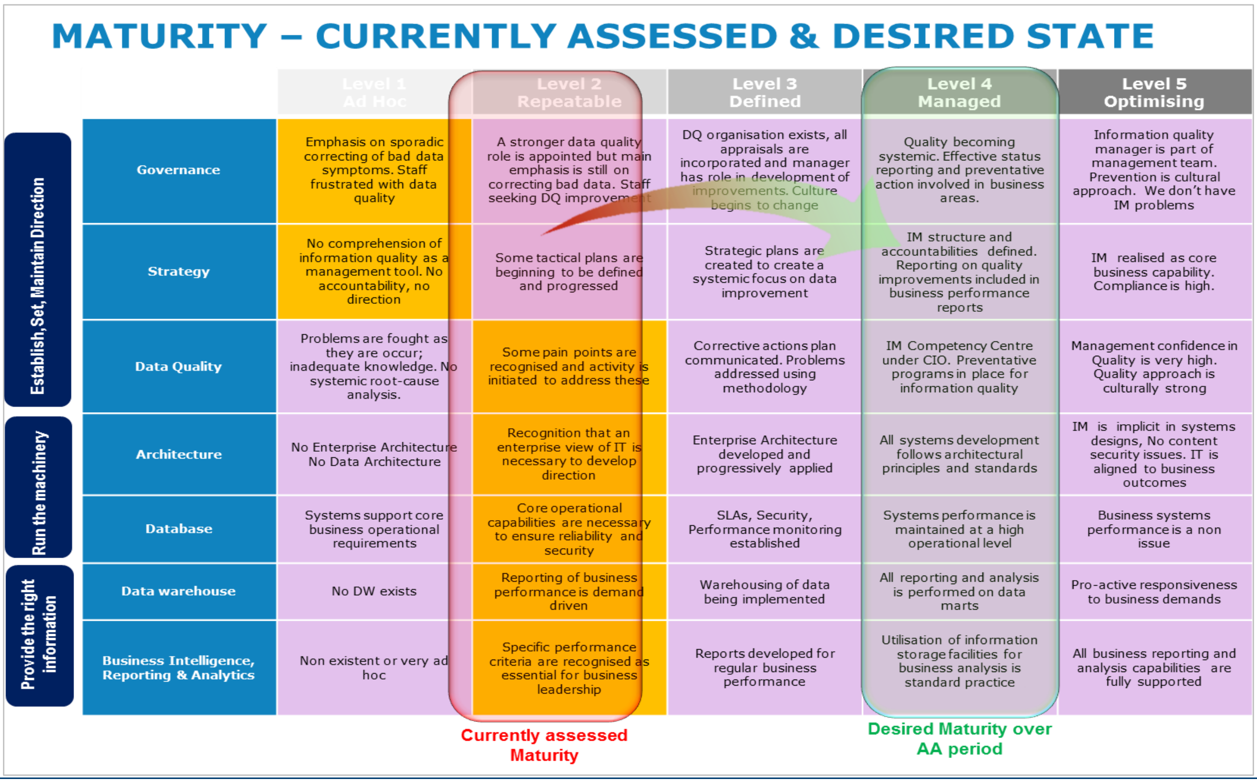
[12] Energy Safe Victoria, *"GPI Safety Management Report 2014/15 – Executive Briefing"*, June 2016, pg.5.
[13] Energy Safe Victoria, *"GPI Safety Management Report 2014/15 – Executive Briefing"*, June 2016, pg.4.
[14] Energy Safe Victoria, *"GPI Safety Management Report 2014/15 – Executive Briefing"*, June 2016, pg. 4.
[15] Energy Safe Victoria, *"GPI Safety Management Report 2014/15 – Executive Briefing"*, June 2016, pg. 5.
[16] Energy Safe Victoria, *"GPI Safety Management Report 2014/15 – Executive Briefing"*, June 2016, pg. 5.
[17] Energy Safe Victoria, *"GPI Safety Management Report 2014/15 – Executive Briefing"*, June 2016, pg. 5.
[18] Energy Safe Victoria, *"GPI Safety Management Report 2014/15 – Executive Briefing"*, June 2016, pg. 8.

- There is a lack of guidelines on information management.
- Information is fragmented across business lines and systems.
- Extensive manual data manipulation causes duplication of effort and gives rise to manual errors.

Based on the formal information management maturity assessment conducted as part of the review, SMS concluded that on a scale of one to five, with one being poor and five being optimal, AGN's information management system was at Level 2. Level 2 was described by SMS as businesses that are able to provide repeatable data management processes (for example collation and reporting) but where information management is ad hoc, demand driven and reactive, rather than being structured and consolidated, providing proactive user driven use of information.

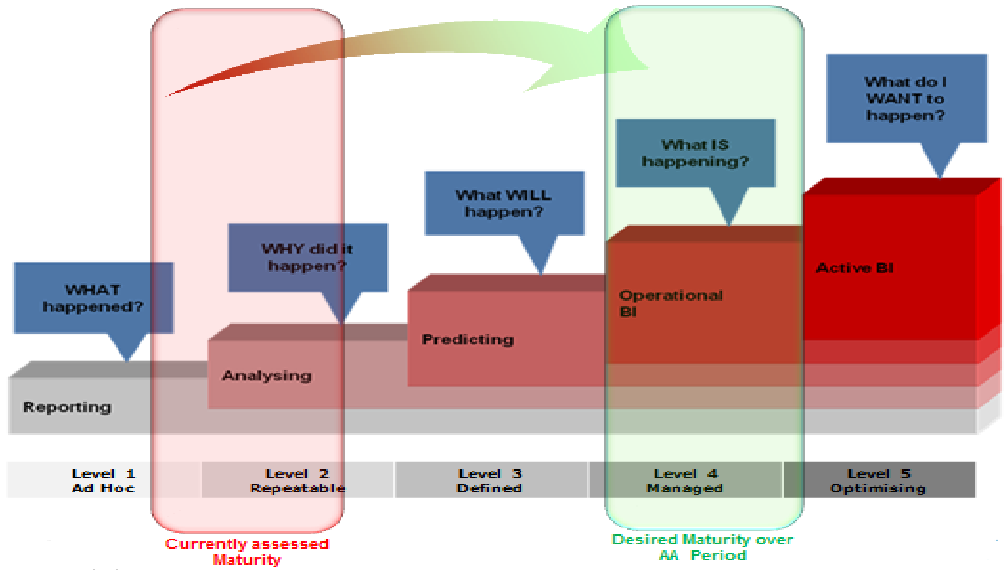
Figure 2 provides more detail on the differences between the various levels of maturity in the SMS Information Management maturity spectrum and the level of maturity that SMS stated that AGN should be aspiring to in the next AA period, which is depicted in Figures 2 and 3.

Figure 1: SMS Information Management Maturity Spectrum



Source: SMS Management & Technology

Figure 2: AGN Information Management Current and Desired Maturity Level



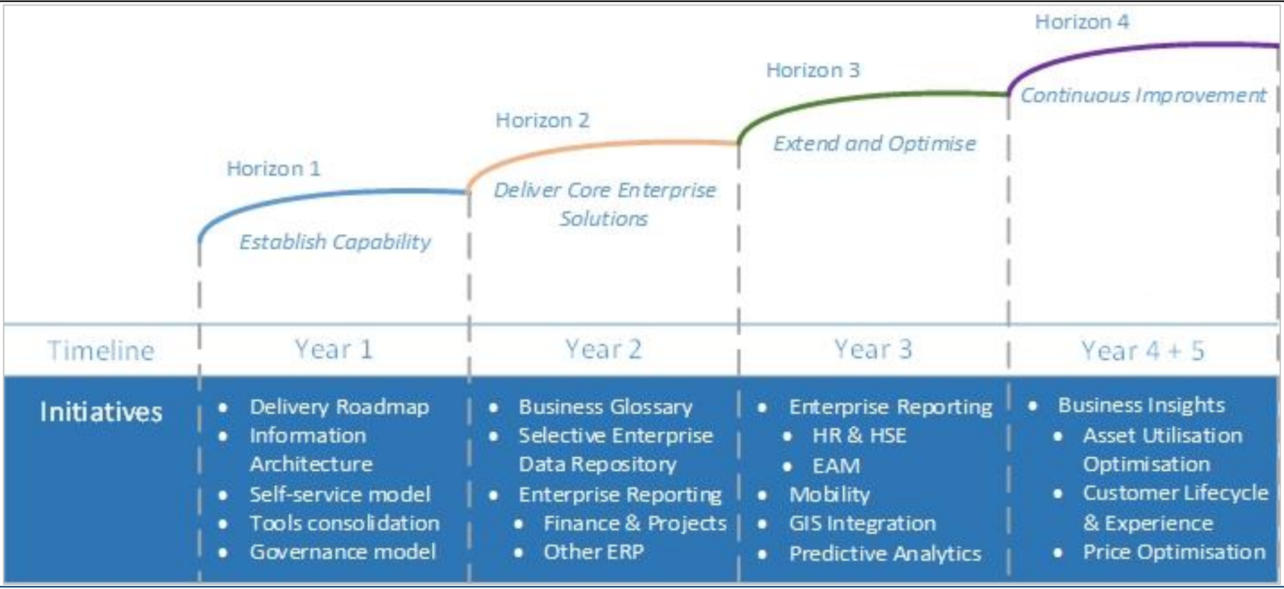
Source: SMS Management & Technology

As can be seen from Figure 2, in order to improve its level of information management maturity, AGN needs, among other things, to consolidate its data into a data warehouse, perform all reporting and analysis on data-marts and implement a strict data governance framework. This will enable data to be consolidated across disparate systems, which will provide greater insight into AGN's Victorian and Albury operations, drive improved decision-making and will be instrumental in moving AGN from Level 2 to Level 4 maturity in information management. To address the issues that SMS has identified AGN will need to start investing in Business Intelligence tools.

1.4.3. Enterprise Information Management Strategy and Roadmap

To address the breadth, size and complex nature of the IT systems and challenges associated with introducing a Business Intelligence platform and achieving a desired state in information management, AGN, with the assistance of SMS, has developed the Enterprise Information Management Strategy and Roadmap depicted in Figure 4.

Figure 3: Enterprise Information Management Roadmap (Year 1 Corresponds to 2018)



Source: SMS Management & Technology

The key outcome from the strategy development was recognising the need to implement a Business Intelligence Toolset that allows consolidated views of data from multiple IT systems (referred to as the 'Selective Enterprise Data Repository' in Year 2 of Figure 4), in conjunction with well-defined data management, analytics and reporting frameworks.

Further detail on the specific problems that AGN has identified with its existing information management and reporting systems and how the Business Intelligence project will overcome these problems is provided in the following sections.

1.4.4. Opportunities for Business Intelligence within the Victorian and Albury networks

There are a number of opportunities for Business Intelligence to yield a range of significant benefits in the Victorian and Albury networks, including improvements to:

- data architecture and governance;
- reporting systems and processes;
- asset and workforce management;
- the management of the safety and integrity of services;
- compliance with regulatory and market related obligations; and
- customer service and marketing.

Further detail on these opportunities is provided below.

1.4.4.1. Improved data architecture and governance

AGN relies on a variety of business IT applications to manage the business and generate required reporting and decision-making information. The key applications that are required for the various functions across the business include:

- the Oracle Enterprise Business suite, which contains financial, purchasing and timesheet information;
- Maximo Asset Management, which includes asset data, work management, purchasing and inventory, health, safety and environment (HSE) related information;
- Customer Care & Billing, which includes customer metering and revenue information;
- Geospatial Information System (GIS), which includes geospatial asset data;
- Synergy, which contains capacity modelling information;
- CHRIS21, which includes Human Resources (HR) data; and
- Learning Management System, which includes training and competency data.

Each of these systems is critical to enabling AGN to prudently and efficiently manage its business operations and contain large volumes of data. For example, the systems contain information on:

- over 650,000 individual gas supply points, including meter serial numbers and Meter Installation Numbers (MIRNs);
- hundreds of thousands of assets, including meters, services, mains, regulators, valves;
- transactions associated with revenue, capex and opex across multiple expenditure lines such as labour, materials, contractors and plant and equipment;
- metering and billing data for over 650,000 individual MIRNs;
- over 125,000 work orders per annum, which consist of information on work and asset data, such as work management information, labour and material costs and asset condition data; and
- HR data for nearly 140 internal employees including payroll information and training and induction records.

The systems that are currently used to manage the business are separate applications, with disparate data structures that are siloed in terms of consolidating the data to provide meaningful information. For example, the way financial information is maintained in Oracle doesn't necessarily map to work data stored in the Maximo Works Management system. As a result, driving reporting and decision-making at a detailed level using consolidated data from these systems is manual, inefficient and cannot provide the level of timely analysis required to identify areas of improvements in the business.

The Business Intelligence project will address these issues through the implementation of a toolset that allows consolidated views of data from multiple IT systems combined with a data governance framework, information management policies and procedures and the alignment of the disparate applications that are used to manage the Victorian and Albury networks. This will, in turn, yield the following benefits:

- information will be easier to access;
- standardised, rationalised and consolidated Information Management processes and tools;
- minimal manual effort will be required to distribute consolidated information;
- the project will provide a common area to publish and consume AGN-wide information;
- improved operational system performance;
- implementation of standard and best practice reporting and analytics; and
- a reduction in information silos.

1.4.4.2. Improved reporting systems and processes

AGN Victoria is required to produce a large number of reports on a daily, monthly, quarterly and annual basis. These reporting requirements are critical to enabling AGN to prudently and efficiently operate the business, ensure compliance with regulatory obligations and facilitate ongoing decision-making.

A summary of AGN's key reporting requirements is provided in Table 1.4.

Table 1.4: Current Reporting Requirements

Type	Reporting Requirements
Regulatory Reporting	The Victorian and Albury networks are required to provide multiple reports to various regulatory bodies, including the AER, Energy Safety Victoria (ESV) and the Australian Energy Market Operator (AEMO). These reports can be required on a daily, monthly, quarterly, annual or ad hoc basis, depending on the report requirements. Often the report content is replicated across different regulatory bodies and it is critical to provide consistent, accurate information to those bodies to comply with AGN's obligations.
KPI Reporting	Key Performance Indicator (KPI) reporting is required to provide Senior Management visibility on the performance of the business and achievement of key strategic goals. These KPIs cover all aspects of the business, including Employee Health and Safety, Networks Safety and Reliability, Customer Service and Financial Performance. The absence of accurate and timely reporting on these KPIs affects the ability of AGN to respond to business issues that impact the prudent and efficient operation of the Victorian and Albury networks.
Management Reporting	Management reporting is critical to ensuring business managers have the appropriate proactive and historical information required to effectively respond to business issues. This reporting covers operational information required to manage work, financial information required to manage costs and customer information required to deal with customer issues. This management reporting is required to ensure managers have the relevant information to their areas of responsibility to drive their business to achieving the business KPIs, address operational issues and meet regulatory obligations.
Financial Reporting	AGN has significant financial information and reporting requirements, including to parent companies, auditors, taxation offices, regulatory bodies (for example Regulatory Information Notices) as well as to internal management. Without this financial information, AGN has an increased risk of financial non-compliance and managers cannot track to agreed budgets and address financial issues in a timely manner.
Asset Performance and Decision Making	AGN produces asset performance reports such as the Distribution System Performance Report, in accordance with AS4645 (Gas Distribution Network Management). These performance reports enable AGN to analyse historical performance and identify priority areas for maintaining the performance of the Network. Without this information, AGN cannot optimise the limited funds available to operate and maintain the Victorian and Albury networks.
Business Submissions	Information from the various systems is also required to inform business submissions, such as Business Cases, changes to regulatory requirements and the addition of new customers such as large sub-divisions. Without the required business information, there is an increased risk that business submissions will be either reduced or rejected.
Customer Queries	Customer query reporting includes a variety of customer interactions, including emergencies, connections to gas, status of work and complaints. Reporting is critical in this case to ensuring AGN manages and improves the customer experience by providing managers transparency on where there are customer service issues.

Meeting these requirements with AGN's current reporting systems requires the collation of significant amounts of data from various IT applications, such as Maximo Works Management, Oracle Financials and Customer Care & Billing. This data is then subject to manual manipulation to provide the appropriate reporting to relevant stakeholders, including external clients, internal management and industry regulators. These processes result in duplication of effort and increased potential for manual errors, time spent checking data for completeness, accuracy and consistency as well as difficulties in disseminating the information in a timely manner. This gives rise to the following issues:

- reporting can only be carried out by a small number of business analysts;
- significant manual effort is required to prepare reports and ensure data accuracy is maintained and validated, which causes duplication of effort and introduces the risk of manual errors;
- difficulties in consolidating data and analysing key data relationships to identify possible operational issues for investigation (for example HR stats with HSE statistics, financial data with work statistics);
- the inability to readily receive up-to-date data;
- inefficient duplication of reporting, potentially resulting in different interpretations of data and reporting results;
- data silos within AGN, which are aligned to business functions and cross functional reporting being extremely onerous; and
- difficulties in replicating the reporting results for different time periods.

In the absence of the Business Intelligence solution, AGN's current reporting systems and processes will continue to require ongoing manual effort to produce reports and will expose AGN to compliance risk. The reporting issues described above are expected to become more pronounced when the Mobility Integration project is implemented, because this will result in an increase in the volume of data to be collated.

The implementation of the Business Intelligence project will overcome these issues by providing for self-service reporting tools, automated periodic and exception reporting and enabling users to access ad hoc reporting information when and where it is required. This will generate a number of benefits, including the following:

- consolidated views of data will be available from various systems to enable cross-functional reporting and minimum manual effort will be required to distribute this information;
- information will be easier to access and the user experience improved;
- the same data will be able to be presented to multiple stakeholders in different views;
- potential operational and financial anomalies will be highlighted for timely investigation and correction;
- improved dissemination of reporting information, including the implementation of 'self-service' reporting, which will mean that users become more self-reliant and able to access varying levels of reporting capability;
- providing the platform for advanced visualisation of data through the GIS application;
- consistency in reporting and presentation of data; and
- provision of an agile reporting platform to facilitate changing reporting requirements from key stakeholders, including external clients and industry regulators.

1.4.4.3. Improved asset and workforce management through improved data analysis and decision-making

The current manual and disparate reporting processes within the Victorian and Albury networks result in difficulties in combining cross-functional data to enable consolidated business decision-making. The manual nature of the processes and data quality issues also result in business analysts focusing on production of reports, rather than detailed analysis to enable improved and efficient decision-making.

The new EAM system and the Mobility Integration project will result in a significant increase in the volume of data available to drive improved asset and work management. This data will include detailed information on contractor costs, internal resource planning and scheduling and work-related asset data. This data has been identified in the EAM Project benefits as integral to achieving improved works management. The Business Intelligence toolset is therefore required to fully realise the EAM benefits.

The Business Intelligence project will enable:[19]

- Better asset maintenance and replacement decisions to be made because users will have access to better information and be able to analyse additional asset data made available through the EAM (for example, maintenance records on individual components of assets and different asset types). This will enable maintenance frequencies to be optimised and maintenance to appropriately target specific asset components.
- More efficient workforce management because it will provide detailed information on job times, locations and durations, which will be able to be analysed to determine optimised works management structures in terms of regions covered by particular field crews. The Business Intelligence tools will also enable skill sets and job types to be analysed to ensure work in a particular region can be completed by the same resources, rather than inefficiently calling in resources from other regions.

AGN's decision-making capability will also be improved through:

- the consolidation of cross-functional data to provide detailed business-wide information;
- the streamlining of the reporting processes and introduction of the data quality framework that will enable business analysts to focus on analytics;
- self-service reporting and the provision of analytical tools to enable agile exception analysis and decision-making; and
- the implementation of Business Intelligence tools to enable analysis of the increased volume and complexity of data provided through the EAM and Mobility Integration projects.

1.4.4.4. Improved safety and integrity of services

The Business Intelligence project will help to maintain and improve the safety of services because it will provide more extensive and timely access to accurate information about assets and the ability to predict failures will result in a safer network. It will similarly help to preserve the integrity of services through rapid and accurate access to asset information. The Business Intelligence tools will also contribute to a reduction in safety related risks and improve the integrity of services in specific parts of the network by providing the tools required to efficiently, accurately and effectively develop asset management models, such as the High Density Polyethylene (HDPE)

[19] If the Business Intelligence project does not proceed, AGN will be constrained in its ability to transform the increasing volumes of data into information that will improve AGN's decision-making capability. An example of this constraint is the inability to combine financial data with the increased volume of operational data now available through the EAM system. Without this capability, the efficiencies that were expected through the EAM project will not be fully realised.

reliability forecast model and Asset Data System reconciliation model (see Box 1.2 for more detail).

Box 0.2: Link between the Business Intelligence project and risk reductions in the network

As noted in Box 1.1, the ESV is concerned that pipeline operators may be more focused on isolated major failures than with "aligned failures or partial failures of a number of physical and procedural barriers". The Business Intelligence project will further optimise AGN's ability to employ a risk based approach to asset management and improve the integrity of services in specific parts of the network through improved data inputs and analysis tools used in asset management models. This will, in turn, enable AGN to:

- more clearly identify assets that are ageing and possibly corroding; and
- more effectively analyse relationships between aligned failures or partial failures of a number of physical and procedural barriers rather than concentrating on isolated major failures.

The Business Intelligence project will increase AGN's capability to carry out this type of modelling and to manage the safety and integrity of services because it will provide for a greater degree of data integration across systems feeding into these models and more effective analysis tools.

For example, to develop the reliability forecasting models, AGN requires information on pipe age, repair data and material analysis to estimate the expected failure rates of mains pipe and more effectively manage the longer term integrity of pipelines (including optimising maintenance and future replacement strategies). The data that is required to develop this model is currently held in several independent systems (Maximo, GIS, Customer metering etc.). Developing the model in the absence of the Business Intelligence toolset would therefore require significant manual processing, which will result in longer time frames being required for the analysis, and the potential for errors and omissions when compared with electronic integration and analysis tools that would be made available through the Business Intelligence project.

Similarly, the Asset Data System reconciliation model, which is used to cross-reference Asset Data with Works Management data to ensure decisions around asset maintenance and replacement are optimised, is also reliant on accurate data that reside across multiple systems. The Business Intelligence project will provide tools to effectively integrate and analyse these data, which in turn will improve the efficiency, accuracy and agility of the model.

1.4.4.5. Improved compliance with regulatory and market obligations

To comply with regulatory and market obligations, significant volumes of data that are currently recorded on paper must be manually entered into various systems such as Maximo, Customer Care & Billing and Oracle Financials, collated manually via paper and entered into various systems. The manual entry of this data gives rise to the risk of inaccurate data being provided to regulatory and market bodies, which could have implications for others in the market.

The Business Intelligence project will reduce the compliance risk by:

- reducing the risk of inaccurate data capture through the introduction of a data quality framework and improved capability to test the data's veracity; and
- reducing the risk of inaccurate reporting due to improvements in the data structures, and the introduction of robust data governance processes and data validation mechanisms.

The outputs of the Business Intelligence project will also enable AGN to optimise the existing risk based approach to asset management as emphasised by the ESV.

1.4.4.6. Other opportunities for Business Intelligence

Other improvements expected from the Business Intelligence project include:

- *Customer service* - The Business Intelligence project, in conjunction with the Mobility Integration project, will improve service delivery to customers by enabling AGN to provide real time responses to queries. The value of this information to customers was noted in the stakeholder engagement program AGN carried out prior to the submission of the proposed AA, as noted in Deloitte's Stakeholder Insights Report:[20]

"Customers would like to access more information from AGN and favour digital channels".

This improved customer service offering is not achievable utilising the existing paper-based processes because they do not facilitate the capture and provision of 'real-time' information.

- *Marketing* - The Business Intelligence project will enable data from the GIS and CC&B (Metering and Billing) systems to be combined to identify high gas consumption areas with gas penetration gaps that can then be used to target marketing in those areas. This will benefit consumers in the longer run, because it will lower the cost of service delivery.

1.4.5. Summary

As the preceding discussion confirms, AGN's current data analytics, reporting, information management and decision making systems require the consolidation of large amounts of information across a disparate and unconnected range of applications. It also requires a substantial amount of manual effort to collate, consolidate and disseminate this information. Apart from being costly to operate and inefficient, the operation of these systems in this manner is exposing AGN to a range of risks and operational inefficiencies and limiting its ability to:

- make informed and efficient decisions;
- achieve further asset and work management related efficiencies through improved decision making;
- efficiently and effectively manage other safety and integrity related risks in the network;
- comply with regulatory obligations; and
- seek out improvements in customer service delivery.

It is for these reasons that AGN, like many of its peers, is proposing to invest in Business Intelligence tools. As highlighted in the detailed Risk Assessment set out in Appendix A the implementation of such tools will reduce the risk level in most of these categories, particularly Health & Safety and Compliance.

1.5. Project objectives, scope and deliverability

1.5.1. Project objectives

The overarching objectives of the Business Intelligence project are to:

- implement a toolset that allows consolidated views of disparate sets of data from multiple IT applications;
- drive improved decision making through additional access to information;
- streamline reporting through standardised reporting tools;
- provide integration into other Enterprise business applications to provide ease of publishing information; and

[20] Deloitte, *"Australian Gas Networks Customer Insights Report, Victorian and Albury Stakeholder Engagement Program"*, May 2016.

- implement prudent and efficient end-to-end business processes to maintain and improve data quality.

Given the enterprise and fully integrated nature of AGN's IT systems, the Business Intelligence project will be rolled out across the networks, with the Victorian and Albury networks' requirements being delivered through Business Intelligence functionality applied to Victorian data. Work on this project is scheduled to commence in January 2018 and be rolled out over a four-year period.

1.5.2. Project scope

As the roadmap in Figure 4 highlights, the Business Intelligence project will involve:

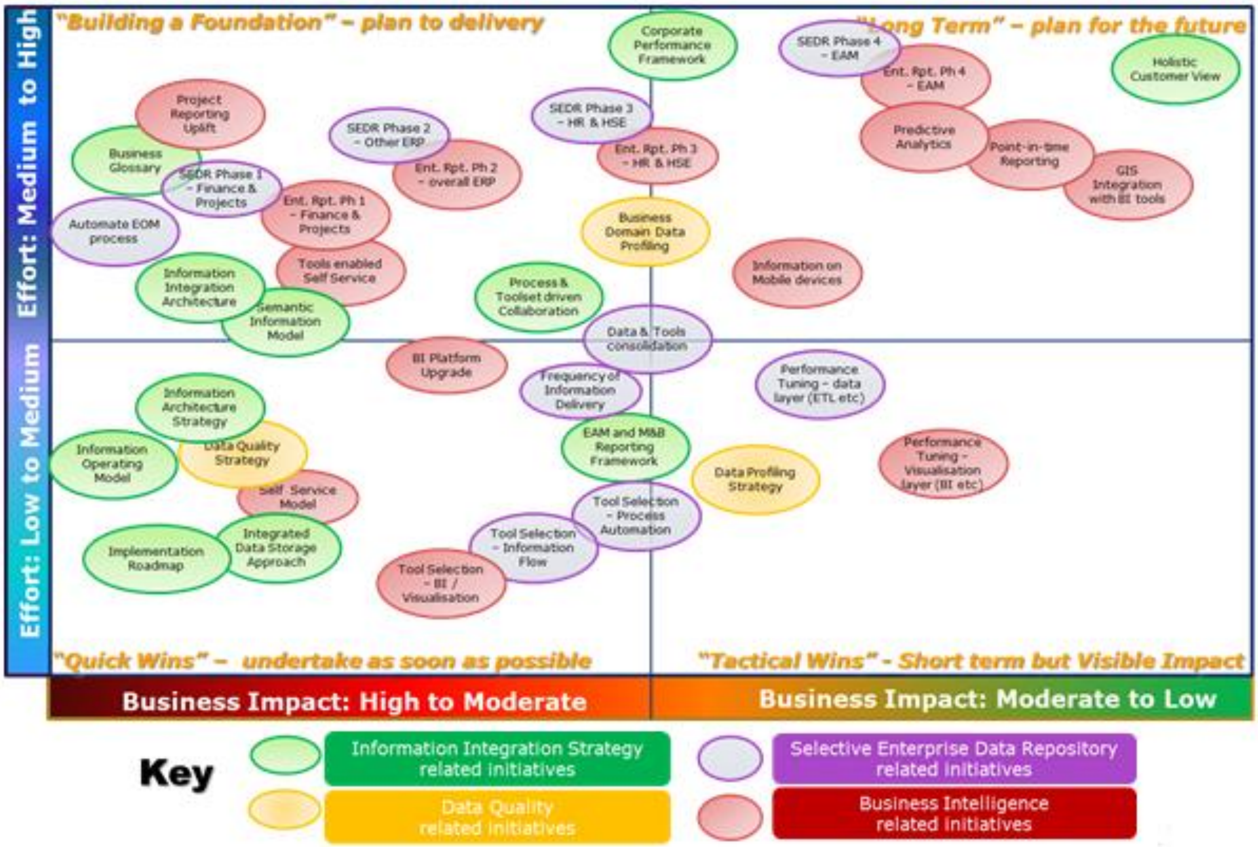
- Establishing the Enterprise Information Architecture, including development of the information architecture model and implementation into existing systems.
- Procuring and implementing a 'Selective Enterprise Data Repository' (SEDR) application as the central Business Intelligence tool.
- Establishing the required reporting and analytics tools, including implementation of a standardised 'self-service reporting' framework.
- Establishing a data quality framework, including associated changes to business processes and human resource impacts.
- System training, including upskilling of existing business analysts and general business users for 'self-service reporting'.

The use of a Selective Enterprise Data Repository has been chosen to allow for an incremental rollout of the Business Intelligence functionality as the various Enterprise IT Systems are brought into the Business Intelligence framework. As a result, the project is forecast to be rolled out over a four-year period.

A four year roll out period has been chosen because the project consists of a number of high and low effort components that must be progressively implemented over an extended period of time through a staged implementation (see Figure 4). The staged implementation will also:

- enable the incremental rollout of the Business Intelligence functionality as the various Enterprise IT Systems are brought into the Business Intelligence framework, which will, in turn, enable some 'quick wins' (i.e. business benefits) to be realised early while also laying the foundation for future Business Intelligence capability; and
- reduce the project's delivery risk and ensure the data, system, processes and governance structures are implemented effectively.

Figure 4: Business Intelligence Project



1.5.3. Timing and deliverability of the project

Work on the Business Intelligence project is due to commence in January 2018 and be completed by 2021. While there will be some overlap between this project and other elements of the IT Plan, AGN's IT services provider, APA Group (APA), has a proven track record in delivering significant IT projects for AGN and its own business on time and within budget.

For example, in the current AA period APA has implemented the Enterprise systems for AGN (e.g. Oracle Financials, Metering & Billing, Asset Management (EAM), Dial Before You Dig and a Data Centre) and a number of other significant IT projects for other areas of its business (e.g. SCADA Upgrades, GIS Implementations and Transmission Market grid services). APA's ability to implement all of these projects on time and within budget reflects its prudent, efficient and structured approach to implementing significant IT projects. It also clearly demonstrates APA's capability to implement the Business Intelligence project in accordance with the timing outlined above and to deliver the expected benefits of the project.

1.6. Economic Value of the Business Intelligence Project (Rule 79 (2)(a))

As the preceding discussion highlights, expenditure on the Business Intelligence Project is justifiable under rule 79(2)(c) because it is necessary to maintain and improve the safety of services (rule 79(2)(c)(i)), maintain the integrity of services (rule 79(2)(c)(ii)) and comply with regulatory obligations (rule 79(2)(c)(iii)). It can also be justified under rule 79(2)(a), because as the analysis that follows shows, the overall economic value of the Business Intelligence project is positive (i.e. the present value of the project's benefits outweighs the project's costs over a 10 year period).

Further detail on the cost-benefit analysis that AGN has carried out and the assumptions underlying this analysis is provided below.

1.6.1. Cost Benefit Assessment

Table 1.5 sets out the assumed profile of the Business Intelligence project's costs and benefits and the project's NPV, which has been calculated on the basis of the following assumptions:

- *Measurement period* - A 10 year period has been used to measure the benefits associated with this project, which reflects the ongoing and long-term nature of the project's benefits. It is also in keeping with the measurement period used by other regulated entities when carrying out similar analysis.[21]
- *Project benefits ($2016)* - The project benefits consist of a mix of tangible and intangible benefits, with the tangible benefits including opex and capex cost savings, opex related avoided costs and EAM benefits, and capex related avoided costs. The intangible benefits, on the other hand, include improved information management, data architecture and governance, ease of access to data, data quality and integrity, reporting, safety, compliance, customer service and marketing opportunities outlined in Section 1.4.4. While the intangible benefits are significant, it has not been possible to quantify their value. The benefits in Table 1.5 therefore only include the tangible benefits and so understate the true economic value of the project.
- *Capex ($2016)* - The capex in the next AA period reflects the cost of implementing the IT infrastructure. In subsequent AA periods, the proposed capex includes the costs of ongoing renewals of the newly implemented Business Intelligence solution ($250,000 every two years). It is worth noting that while the costs of the Business Intelligence solution renewals have been included in the NPV analysis, these costs are not included in the allowance being sought for this project or for the V46 Applications Renewal business case because these costs will only commence in the following (2023 to 2027) AA period.
- *Discount rate* - A discount rate of 3.14% has been used, which is AGN's proposed real pre-tax Weighted Average Cost of Capital (WACC).

As the final row in Table 1.4 shows, the Business Intelligence project is expected to yield a positive economic value of $1,196 ($000, 2016) over a 10 year period from the year in which benefits are first realised and is therefore justifiable under rule 79(2)(a).

Further detail on the benefits and costs of this project is provided in the following sections.

21 See for example, SAPN, "*IT Field Force Mobility Business Case Addendum 1*", Attachment G.15, 3 July 2015.

Table 1.5: NPV Calculation ($000, 2016)

Year since start		0	1	2	3	4	5	6	7	8	9	10
Calendar Year	**Total**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Costs												
Total capex	11,828.2	2,555.8	5,039.1	3,359.4	123.9	-	250.0	-	250.0	-	250.0	-
Discounted capex	**10,972.6**	**2,478.0**	**4,736.9**	**3,061.8**	**109.4**	**-**	**207.7**	**-**	**195.2**	**-**	**183.5**	**-**
Benefits												
Cost avoidance												
Capex - Cost Avoidance	6,865.7	-	201.9	403.9	605.8	807.7	807.7	807.7	807.7	807.7	807.7	807.7
Total cost avoidance	**6,865.7**	-	201.9	403.9	605.8	807.7	807.7	807.7	807.7	807.7	807.7	807.7
Discounted cost avoidance	**5,516.9**	**-**	**189.8**	**368.1**	**535.3**	**692.0**	**671.0**	**650.5**	**630.7**	**611.5**	**592.9**	**574.9**
Cost savings												
Opex - Cost Savings	3,800.0	-	380.0	380.0	380.0	380.0	380.0	380.0	380.0	380.0	380.0	380.0
Opex - EAM benefits	2,150.0	-	215.0	215.0	215.0	215.0	215.0	215.0	215.0	215.0	215.0	215.0
Capex - EAM benefits	2,150.0	-	215.0	215.0	215.0	215.0	215.0	215.0	215.0	215.0	215.0	215.0
Total Opex cost savings	**5,950.0**	-	595.0	595.0	595.0	595.0	595.0	595.0	595.0	595.0	595.0	595.0
Total Capex cost savings	**2,150.0**	-	215.0	215.0	215.0	215.0	215.0	215.0	215.0	215.0	215.0	215.0
Total cost savings	**8,100.0**	-	810.0	810.0	810.0	810.0	810.0	810.0	810.0	810.0	810.0	810.0
Discounted cost savings	**6,651.5**	**-**	**761.4**	**738.3**	**715.8**	**694.0**	**672.9**	**652.4**	**632.5**	**613.3**	**594.6**	**576.5**
Total benefits	**14,965.7**	-	**1,011.9**	**1,213.9**	**1,415.8**	**1,617.7**	**1,617.7**	**1,617.7**	**1,617.7**	**1,617.7**	**1,617.7**	**1,617.7**
Total discounted benefits	**12,168.4**	**-**	**951.3**	**1,106.3**	**1,251.1**	**1,386.0**	**1,343.8**	**1,302.9**	**1,263.3**	**1,224.8**	**1,187.5**	**1,151.4**
Total												
Discounted costs	10,972.6	2,478.0	4,736.9	3,061.8	109.4	-	207.7	-	195.2	-	183.5	-
Discounted benefits	12,168.4	-	951.3	1,106.3	1,251.1	1,386.0	1,343.8	1,302.9	1,263.3	1,224.8	1,187.5	1,151.4
NPV	**1,195.7**	**(2,478.0)**	**(3,785.7)**	**(1,955.5)**	**1,141.7**	**1,386.0**	**1,136.2**	**1,302.9**	**1,068.0**	**1,224.8**	**1,004.0**	**1,151.4**
Does Expenditure Satisfy Rule 79(2)(a)?	**Yes**											

1.6.2. Benefits

The opportunities expected from the implementation of the Business Intelligence project are set out in detail in Section 1.4.4. These opportunities will yield a number of tangible and intangible benefits, the ultimate beneficiaries of which will be AGN's customers who will benefit from improvements in customer service and lower cost services.

Tangible benefits

The tangible benefits include the opex related cost savings, opex related avoided costs, EAM benefits and capex related avoided costs. Further detail on the sources of these benefits is provided in Table 1.6, while Table 1.7 sets out the estimated value of these benefits.

Table 1.6: Tangible Benefits

Benefit	Description of benefit
Opex cost savings	
Current data analysis and reporting	The Business Intelligence project will generate data validation, reporting and analysis related efficiencies. The opex cost savings forecast assumes that [redacted] that would otherwise be required to develop reports, correct data, validate data etc. is no longer required because the processes are streamlined.
Additional data analysis, reporting data validation and correction	The introduction of the EAM has increased the volume of data available to drive improved work management and as such has increased the costs incurred by AGN in relation to analysis of this data. These costs amount to approximately [redacted] p.a.
Opex related EAM benefits	
EAM benefits realisation	The Business Intelligence project is required to realise the final 20% of EAM benefits in the Victorian and Albury networks as they require significant analysis of data to drive the relevant business change. Based on the Business Intelligence initiative facilitating the [redacted] million per year of Victorian related benefits, this project will result in a benefit of $430,000 p.a. These benefits are evenly split between capex and opex as EAM benefits are applicable equally to opex and capex related activities.
Capex related avoided costs	
Asset Replacement, maintenance and works management decisions	The Business Intelligence project will enable AGN to make more informed decisions about: • *Asset replacement and asset design.* For example, improved access to data would assist capacity modelling ensure that asset design and timing of construction is optimised. • *Asset maintenance versus asset replacement.* For example, improved access to the additional asset data made available through the EAM will also enable maintenance frequencies to be optimised and maintenance to target specific asset components that can be identified as showing signs of deteriorating reliability. • *Works management.* For example, detailed information on job times, locations and durations, will enable optimised works management structures to be put in place, which will yield further efficiencies In AGN's view an average saving of 0.75%[22] on the annual forecast capex spend over the next AA period ($107.7 million) is achievable given the nature of the improvements outlined above. Because the Business Intelligence infrastructure will be rolled out over a four year period, these benefits are assumed to ramp up over the first three years of the project with 25% of the benefits to be achieved in 2019, 50% in 2020, 75% in 2021 and 100% by 2022.

[22] On some capex projects the use of Business Intelligence tools is likely to yield greater savings than 0.75% while for other projects the use of these tools may yield a smaller saving. On average, however, a 0.75% capex saving is expected to be achieved.

Intangible benefits

In addition to the tangible benefits set out above, the Business Intelligence project will also yield a range of intangible benefits outlined in Section 1.4, including improved information management, data architecture and governance, data quality and integrity, reporting, safety, compliance, customer service and marketing opportunities. Given the intangible nature of these benefits it has not been possible to quantify the benefits, so they have not been included in Tables 1.6 and 1.7 or the NPV analysis in Table 1.5.

1.6.3. Forecast costs

1.6.3.1. Costing methodology

The Business Intelligence project is a national project. The total project cost has therefore been estimated on the basis of the work that is needed to be carried out across all Australian jurisdictions that AGN operates in. The approach that AGN has used to estimate the total project costs for the Business Intelligence project is the same as the approach that it used to estimate the costs of the South Australian component of the Business Intelligence project (which has been recently approved by the AER in its Final Decision) and is outlined below:

- AGN utilises an industry standard Business & Technology (B&T) Project Methodology, which is managed through formal governance. This B&T Methodology divides the projects into key stages – concept, develop, plan, deliver and close. Each stage consists of key tasks and activities to ensure the consistency and standardisation across projects. The project methodology is outlined in Appendix C.
- To ensure project estimates are developed in a consistent manner, AGN utilises an Estimation Tool, which is aligned with the B&T Project Methodology. This estimation tool has been used to forecast the work and cost estimates for the application upgrade program of work. This estimation tool utilises historic figures from the current AA period for resource work effort estimates. All historic figures are sanity checked to ensure any changes to the way historical projects were carried out were taken into account. The work estimates are based on a complexity matrix tool, which uses a series of questions to categorise projects into simple, medium and complex.
- The material and direct labour costs, and applicable planning, design and commissioning charges, are based on historic actual costs of similar projects and on vendor quotes subject to a competitive tendering process in accordance with the APA Procurement policy and guidelines[23]. Resource Unit Costs (both internal and external) are based on AGN's Project Management Office (PMO) research, where actual placement costs have been used based on historical project resources and current resourcing rates (2016).
- The historic figures and work effort estimates are used as inputs into the final estimates, which are subject to stringent review and endorsement by members of the IT Estimates Review Committee. The work effort, cost and timing of projects are monitored throughout the project lifecycle to ensure on time and on budget delivery.
- When implementing the project, AGN will use a formalised Project Methodology and utilise a combination of internal and external resources (through vendors and trusted recruitment agencies) to deliver the program of work to ensure that services are carried out in a prudent and efficient manner. The Project Methodology is outlined in Appendix D and provides a consistent, standard and quality assured project implementation framework. The PMO will provide guidance and governance to the project, ensuring that the work is carried out in a prudent and efficient manner.

[23] These documents are available on request.

A key principle that has been employed when developing these estimates is that enterprise economies of scale achieved through utilising standardised business processes, data models, data migration techniques and existing hardware platforms should be reflected in the estimate (see the IT Investment Plan for more detail).

The portion of these costs that should be attributed to the AGN Victorian and Albury networks has been based on the proportion of customers supplied by these network businesses (51.35% and 1.79%, respectively as at 31 December 2015).

Victoria and Albury's share of the costs of the national Business Intelligence project has therefore been estimated to be:

- $11,078.2 ($000, 2016) in the next AA period to design, build and implement the new Business Intelligence toolset, which will be carried out over a four year period commencing in 2018 (see Appendix B for more detail on this cost); and
- $250.0 ($000, 2016) every second year in subsequent AA periods for applications renewals, which has been calculated using the same assumptions that AGN used for the V46 Application Renewals Business Case.

1.6.3.2. Forecast Cost Breakdown for the Next AA Period

A breakdown of the total project cost by project phase is provided in Appendix B, while the tables below provide a number of cost breakdowns for the next AA period.

Table 1.8: Capex / Opex Split ($000, 2016)

	2018	2019	2020	2021	2022	Total
Capex	2,555.8	5,039.1	3,359.4	123.9	-	**11,078.2**
Opex	-	-	-	-	-	**-**
Total	**2,555.8**	**5,039.1**	**3,359.4**	**123.9**	**-**	**11,078.2**

Note: Totals may not exactly match the sum of individual costs due to rounding.

Table 1.9: Project Cost Estimate, By Cost, Capex ($000, 2016)

	2018	2019	2020	2021	2022	Total
Direct Labour	938.8	1,471.4	980.9	123.9	-	**3,515.0**
Contracted Labour	1,526.	2,823.2	1,882.1	-	-	**6,231.3**
Hardware, Software and Maintenance	-	662.5	441.7	-	-	**1,104.2**
Travel, Sundry, Other	91.1	82.0	54.6	-	-	**227.7**
Total	**2,555.8**	**5,039.1**	**3,359.4**	**123.9**	**-**	**11,078.2**

Note: Totals may not exactly match the sum of individual costs due to rounding.

Further detail on how the labour and vendor cost components of this forecast have been developed is provided below.

1.6.3.3. Labour requirements

The Business Intelligence Project will require a mix of external and internal IT resources.

The internal resource costs have been estimated from the bottom up by breaking the project into stages and tasks and considering the requirements (skill set and time) for each task. Where additional specialist internal resources need to be brought to the project, the hourly rates are differentiated by resource types and are based on the current market rates for these roles. The internal labour costs include the following:

- internal project management;
- change management;
- business process re-design;
- system integration;
- business analyst and Subject Matter Expert (SME) support; and
- training.

1.6.3.4. Vendor costs

External vendor cost estimates have been provided by independent consultants, SMS Management and Technology, and include the following:

- external project management;
- application design;
- system build; and
- system implementation.

1.7. Consistency with the National Gas Rules

As the analysis in the preceding sections show, the Business Intelligence project is justified under rule 79(2)(a) of the NGR because the overall economic value of the project is positive. The project is also justified under rule 79(2)(c) because it is necessary to:

- *maintain and improve the safety of services (rule 79(2)(c)(i))* - more extensive access to accurate information about assets and the ability to predict failures will result in a safer network;
- *maintain the integrity of services (rule 79(2)(c)(ii))* - the integrity of services will be maintained through rapid and accurate access to asset information; and
- *comply with a regulatory obligation or requirement (rule 79(2)(c)(iii))* - access to more extensive and accurate asset information will decrease the time required to meet regulatory reporting periods.

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN also considers the forecast capex for this project to be:

- *Prudent* – The proposed expenditure is of a nature that a prudent service provider would incur because it is necessary to maintain and improve the safety and integrity of services, comply with regulatory and market obligations and will also enable AGN to:
    - make more informed and prudent decisions about asset management, work force management and other areas of the business;
    - seek out improvements in customer service delivery, the safety and integrity of services and compliance with regulatory obligations; and
    - the project will also yield a positive economic value.
- *Efficient* – The Business Intelligence project is cost effective and will enable AGN to improve operational efficiency, potential customer and business interruptions and corresponding compliance and financial impacts. The expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.
- *Consistent with accepted good industry practice* – The Business Intelligence project will enable AGN to have rapid access to critical information when making decisions, which is in line with good industry practice. The project will also address the risks of non-compliance with relevant regulatory obligations through improved reporting and analytical capability. The fact that so many of AGN's counterparts are also investing in this area, as approved by the AER, also demonstrates the consistency of this expenditure with good industry practice. SMS findings on the relative immaturity of AGN's information management capabilities also highlight the fact that AGN is well behind where it would be expected to be if it its systems were consistent with good industry practice and that investment is required in this area to enable AGN to catch-up to others.
- *To achieve the lowest sustainable cost of delivering pipeline services* – The Business Intelligence project will enable more informed decision making throughout the business and, in so doing, enable AGN to deliver the lowest sustainable cost of delivering pipeline services.

The proposed expenditure on the Business Intelligence project can therefore be viewed as conforming capex under rule 79 of the NGR.

Appendix A – Risk Assessment

The risk assessment for all options considered in this business case has been carried out in accordance with the APA Group Risk Management Policy. The summary of the risk assessment for the untreated risk and residual risk after implementation of the Business Intelligence project is provided below.

It can be seen that this project will reduce the likelihood of most consequence categories, most notably Compliance, and the overall risk rating reduces to Low.

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Option Risk
Risk Untreated (i.e. Do Nothing)	**Likelihood**	*Unlikely*	*Rare*	*Possible*	*Possible*	*Unlikely*	*Possible*	*Possible*	**MODERATE**
	Consequence	*Minor*	*Minor*	*Minor*	*Minor*	*Minor*	*Medium*	*Minor*	
	Risk Level	*Moderate*	*Negligible*	*Low*	*Low*	*Low*	*Moderate*	*Low*	
Residual Risk (i.e. after Business Intelligence project implemented)	**Likelihood**	*Rare*	*Rare*	*Unlikely*	*Unlikely*	*Rare*	*Rare*	*Unlikely*	**LOW**
	Consequence	*Minor*	*Minor*	*Minor*	*Minor*	*Minor*	*Medium*	*Minor*	
	Risk Level	*Low*	*Negligible*	*Low*	*Low*	*Negligible*	*Low*	*Low*	

Appendix B – Detailed Cost Estimate

The implementation cost breakdown by the project stage is provided below.

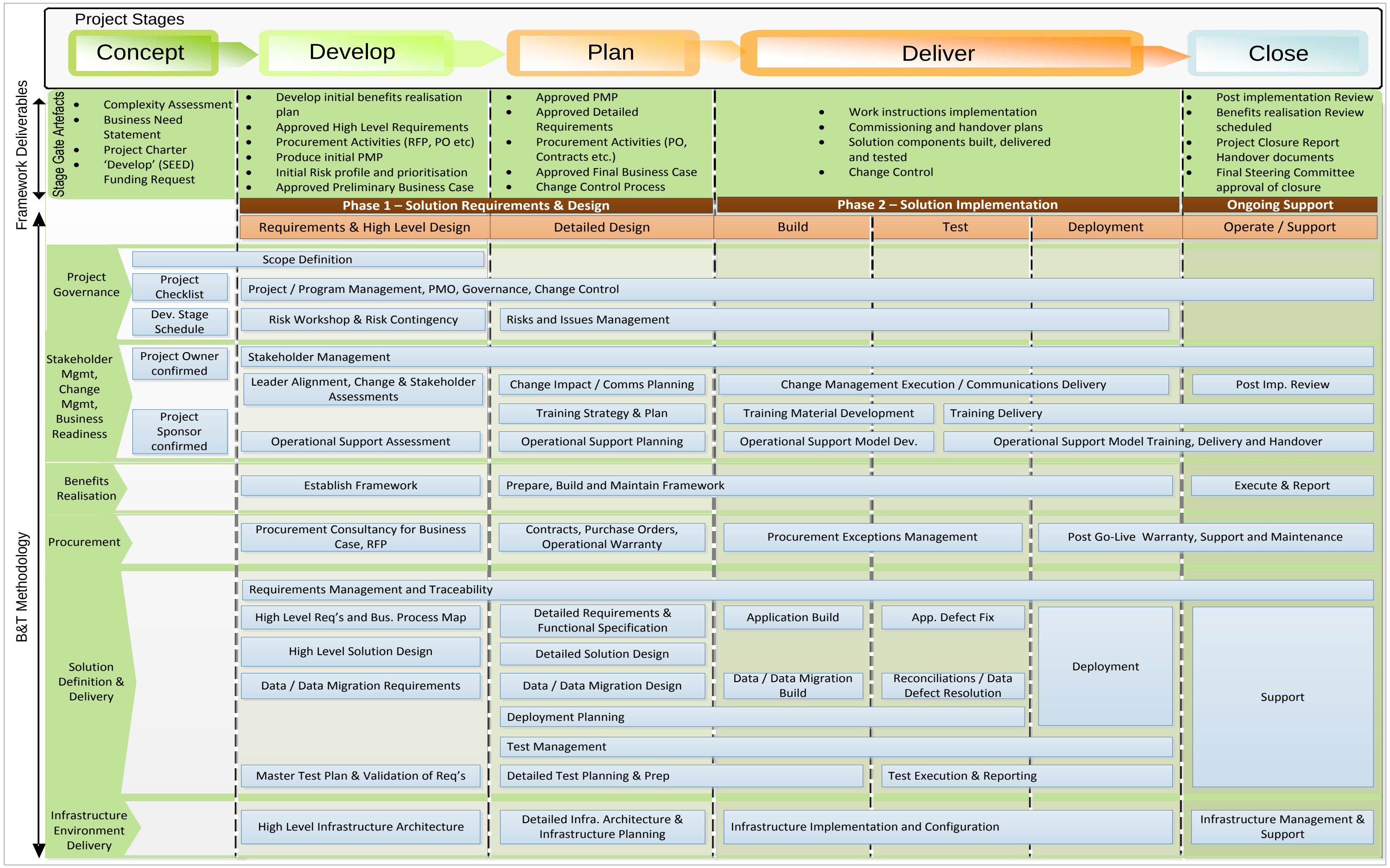
Table B.1: Business Intelligence Toolset Capex by Stage

IT & ICT Procurement Estimations Template: B&T Projects		
Project Name:	BI Platform	
Project Complexity:	Complex	
Project Type:	Major Change	
Estimations Summary		
Total Project (end to end)	Effort (Days)	Total cost
End to End Total	2,819	11,078,179
Estimations by Project Stage		
Develop Stage Total	339	479,399
Plan Stage Total	436	2,076,449
Deliver Stage Total	1,939	8,398,473
Close Stage Total	105	123,857

Appendix C – Methodologies

AGN Project Methodology

To manage all its IT projects, AGN utilises an industry standard Business and Technology (B&T) Project Methodology, which is managed through formal governance. The key aspects of this methodology are outlined in the diagram below.



Business Case – Capex V48

Mobility Integration

1.1. Project Approvals

Table 1.1: Project Approvals:

Prepared By	Peter Butler, *Manager Network Support Services*
Approved By	John Ferguson, *Group Executive Networks*

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	Australian Gas Networks Limited's (AGN) Victorian and Albury network businesses currently rely on paper-based manual processes for the majority of their field based activities, including work management, health, safety and environment (HSE) management, technical work procedures and asset information collation. The use of these processes is costly and inefficient because information must be manually entered into numerous systems, which can result in data integrity issues, double handling of information and delays in information becoming available. The use of these processes also exposes AGN to a range of safety, operational, customer and financial risks and means that AGN is constrained in its ability to: • realise the full benefits of the Enterprise Asset Management (EAM) system, including more efficient resource management, resource location and response times; • improve service delivery to customers through faster response times and providing real-time status updates on network outages and service requests; • improve the safety of services by, for example, providing field crews with real time safety related information and up to date asset data through the Dial Before You Dig (DBYD) service and employees and contractors' mobile devices; • improve the integrity of services through more informed decision making and reductions in operational errors from manual processing of data; • comply with regulatory and market obligations through the timely reporting of accurate information; • optimize the use of a risk-based approach to asset management with risk mitigation measures underpinned by 'effective analysis' as Energy Safe Victoria (ESV) is now requiring of Victorian gas distributors; and • avoid future cost increases through optimised mobile workforce management and improved decision making. The Mobility Integration project involves the implementation of an enhanced mobile communications platform, which will be integrated into the EAM suite of Information Technology (IT) applications and Geospatial Information System (GIS). It will enable field data to be captured into core operational systems and real-time information to be transmitted to the field. The implementation of this project will enable AGN to

	implement more efficient: • work management processes and practices in the field, which will support more informed decision making (for example, mobile solutions can support job assignments, provide field crews with instructions and real-time asset and safety information, and facilitate the timely transfer of information between the field, back-office systems and customers); • compliance reporting and processes; and • end-to-end business processes that automate EAM and GIS functionality through mobility (for example, by automating paper-based and manual processes). Apart from providing for greater efficiency in the field and across the business, the Mobility Integration project is also expected to result in improvements in customer service delivery (for example, by reducing response times and providing accurate and timely information on outages and service requests), the safety, security and integrity of services, and compliance with regulatory obligations. This proposed project forms part of AGN's National Mobility Strategy and Roadmap. The South Australian component of this project has been recently approved by the Australian Energy Regulator (AER) in its Final Decision for the South Australian network. In approving this project for South Australia, the AER noted that it was satisfied that the proposed expenditure "*is justifiable under rule 79(2)(a)*" and that "*this capex would be incurred by a prudent service provider acting efficiently and that it is conforming capex under rule 79*" of the National Gas Rules (NGR).[1]
Economic Value of Mobility Integration	The Mobility Integration project will yield a number of tangible and intangible benefits, with the tangible benefits including avoided costs and cost savings while the intangible benefits include the safety, customer service and decision making benefits outlined above. The tangible benefits alone are expected to reach $18,469.6 ($000, 2016) over the first 10 years of the project's life, while the cost of implementing and maintaining the Mobility Integration solution over the same period is $12,188.1 ($000, 2016)[2]. The excess of benefits over costs is $6,281.5 ($000, 2016), or approximately 50%, and equates to a positive Net Present Value (NPV) of $3,708 ($000, 2016). If the intangible benefits could be quantified, then the difference between the benefits and costs would be even greater. As this analysis highlights, implementing the Mobility Integration project in the Victorian and Albury networks will yield a positive net economic value, the beneficiaries of which will be customers in these networks.
Estimated Cost	The total forecast capital expenditure (capex) for this project is $11,588.1 ($000, 2016), of which: • $1,207.2 ($000, 2016) will be spent in the current (2013 to 2017) Access Arrangement (AA) period; and • $10,380.9 ($000, 2016) will be spent in the next (2018 to 2022) AA period.

Consistency with the National Gas Rules (NGR)	The Mobility Integration project complies with the new capex criteria in rule 79 of the NGR because:
	• 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)); and
	• it is justified under rules 79(2)(a) and (c), because:
	  ◦ the overall economic value of the capex is positive (rule 79(2)(a)); and
	  ◦ the expenditure is also necessary to:

1 AER, *"Final Decision: Australian Gas Networks Access Arrangement 2016 to 2021"*, Attachment 6 – Capital expenditure, May 2016, pg. 6-35.

2 In addition to the implementation costs of $11,588.1 ($000, 2016), the total capex over the 10 year period includes the costs of ongoing renewals of the newly implemented Mobility Integration solution ($200,000 every two years).

	○ *Maintain and improve the safety of services (rule 79(2)(c)(i))* - The Mobility Integration project offers a number of opportunities to reduce health and safety risk to both the workforce and the public. ○ *Maintain the integrity of services (rule 79(2)(c)(ii))* - The Mobility Integration project will allow more accurate data to be extracted and utilised for improved decision making. There will also be less operational errors from manual processing of data, which will improve the integrity of the services provided. ○ *Comply with a regulatory obligation or requirement (rule 79(2)(c)(iii))* - The Mobility Integration project will reduce the delays in service provision and meeting regulatory obligations and will also ensure that data is available to demonstrate compliance. The project will also enable AGN to optimise the existing risk-based approaches to asset management that are a key focus of the ESV.
Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Safety, Reliability and Customer Service themes as its implementation will allow AGN to continue to maintain the safety of the network, whilst continuing to provide a highly reliable supply of natural gas to AGN's customers and enabling further improvements in customer service (e.g. by reducing response times and providing accurate and timely information on outages and service requests). More information detailing the results of AGN's stakeholder engagement program is provided in Chapter 5 of the Access Arrangement Information document.
Supporting Information	• V48 Supporting Information 1 (NPV & Options Analysis) • V48 Supporting Information 2 (ESV GPI Safety Management Report Executive Briefing) • V48 Supporting Information 3 (ESV GPI Safety Management Report 2014-2015 Non-licensed Gas Infrastructure)

1.3. Background

Australian Gas Networks Limited (AGN) maintains and operates a number of critical Information Technology (IT) systems that are integral to the efficient and effective management of the Victorian and Albury networks and are required to meet a range of legal and regulatory obligations, including those prescribed in the:

- National Gas Law (NGL) and National Gas Rules (NGR);
- Victorian Gas Distribution System Code[3];
- Victorian Gas Industry Act 2001[4];and
- Victorian Retail Market Procedures[5] (Retail Market Procedures).

These obligations predominantly relate to safely and effectively managing a gas distribution network, ensuring accuracy and timeliness of retail market transactions and delivering against prescribed customer service levels.

They are also required to meet Energy Safe Victoria's (ESV's) gas and pipeline safety requirements[6].

3 Essential Services Commission, "*Gas Distribution System Code*", Version 11.0.
4 http://www.austlii.edu.au/au/legis/vic/consol_act/gia2001167/
5 AEMO, http://www.aemo.com.au/Gas/Policies-and-Procedures/Retail-Gas-Market-Procedures/Victoria
6 http://www.esv.vic.gov.au/About-ESV

As a prudent operator, AGN has ongoing maintenance plans for its critical IT systems, which are based on the appropriate risk assessments, to ensure continued compliance with these legal, regulatory and safety obligations.

AGN's IT Environment

Given the highly integrated nature of AGN's IT environment, upgrades and improvements to these systems have been incorporated into a detailed *Information Technology Investment Plan*[7] (IT Plan), which has been provided as Attachment 8.5 to AGN's Access Arrangement Information (AAI) document.

This IT Plan details the proposed IT capital program of work over the next AA period, as well as acting to support AGN's business objectives, which, in turn, are aligned with the stakeholder expectations identified during the stakeholder engagement program recently undertaken by AGN in Victoria and Albury[8].

In the current AA period, a number of major projects to nationalise and upgrade key IT application systems were implemented. These projects delivered improved IT systems with increased scalability, flexibility and reliability, while also ensuring that AGN continues to meet its obligations under the RMP and other relevant regulatory and customer obligations. The IT systems nationalisation program has so far successfully delivered to Victoria and Albury the Enterprise Asset Management (EAM) system, the National Metering and Billing (MnB) system and other core foundation platforms to leverage efficiencies in business operations through data consolidation, enablement of standard national processes and task automation.

Additional projects to complete the nationalisation program during the next (2018 to 2022) AA period have been included in separate business cases. The completion of the nationalisation program of work is required in order for AGN to realise the full business benefits from moving towards the national enterprise structure and the integrated suite of systems, including enhanced EAM capability, streamlined and scaled applications and processes, and improved risk mitigation. The ultimate beneficiaries of these improvements will be AGN's customers.

This business case focuses on the Mobility Integration Project. The remainder of this business case outlines the rationale for the Mobility Integration project, the objectives, scope and timing of the project, the economic value of the project and the consistency of the project with the NGR. The South Australian component of this project has been recently approved by the Australian Energy Regulator (AER) in its Final Decision for the South Australian network.

In approving this project for South Australia, the AER noted that it was satisfied that the proposed expenditure "*is justifiable under rule 79(2)(a)*" and that "*this capex would be incurred by a prudent service provider acting efficiently and that it is conforming capex under rule 79*" of the National Gas Rules (NGR).[9]

1.3.1. National Mobility Strategy and Roadmap

The Mobility Integration Project is guided by the AGN National Mobility Strategy and Roadmap, which has been developed to address the potential broad scope and highly integrated nature of mobility applications. The National Mobility Roadmap consists of three distinct streams of work:

- Advanced Collaboration;

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[7] APA, *"Victorian and Albury Networks Information Technology Investment Plan for the 2018 to 2022 Access Arrangement Period"*, July 2016

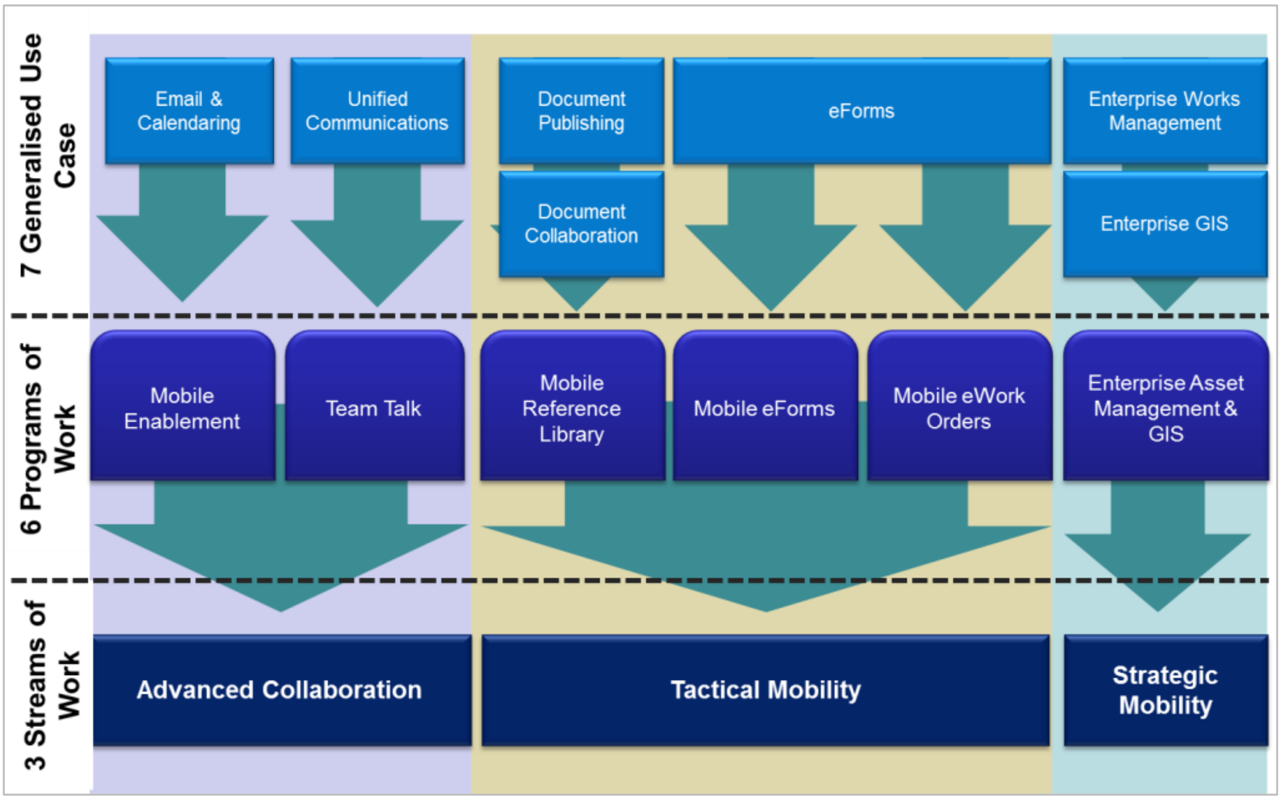
[8] Deloitte, *"Australian Gas Networks Customer Insights Report, Victorian and Albury Stakeholder Engagement Program"*, May 2016.

[9] AER, *"Final Decision: Australian Gas Networks Access Arrangement 2016 to 2021"*, Attachment 6 – Capital expenditure, May 2016, pg. 6-35.

- Tactical Mobility; and
- Strategic (Integrated) Mobility.

These three streams of work are shown in **Error! Reference source not found.**, along with the work to be carried out in each phase. As this figure shows, mobility functionality is being progressively implemented into the business through the Advanced Collaboration, Tactical Mobility and Strategic Mobility work streams. The Mobility Integration project forms part of the Strategic Mobility work stream, which is the final step on the AGN Mobility Roadmap.

Figure 1: AGN Mobility Roadmap



In total there are six programs of work to be carried out under the Mobility Strategy Roadmap, which entail the following:

- *Mobile Enablement* - Equip the workforce with Smartphone 'tools of trade' that enhance productivity by enriching communications.
- *Team Talk* - Extend existing collaboration tools with annotation and desktop/mobile video to create a richer collaboration environment.
- *Mobile Reference Library* - Replace the extensive collection of paper reference materials (e.g. Red/Blue books, maps, reference materials in huts) with tablets containing offline readable copies.
- *Mobile e-Forms* - Provide a way for business groups to replace key paper forms with electronic forms that will display on a variety of mobile devices. Add new functionality to traditional forms by allowing the inclusion of photographs, exact GPS locations, safety information, immediate validation, etc.
- *Mobile e-Work Orders* - Implement work orders as e-Forms that are electronically sent to the worker, completed in the field and sent back when complete. These will replace the current

method of communicating work orders by phone and paper, but does not involve dispatch optimisation or provide integration in back-end systems.

- *Mobility Integration with Enterprise Asset Management & GIS* - Drive consistent, optimised work processes through mobile integration with the EAM system (Maximo) and Geospatial Information System (GIS). Improve compliance and safety outcomes through access to real time data and enterprise content.

These programs take an incremental approach to the implementation of the Mobility Strategy and each program progressively lays the foundation for the next program as the business matures in the use of mobile technology. Work on the Mobility Strategy implementation commenced in 2012. To date, Mobile Enablement and Team Talk programs have been completed and Mobile e-Forms and e-Work orders have commenced and are in progress. It is anticipated that the first five programs will be implemented by June 2017, before the start of the final program. The final program (program 6), which will involve implementing an enhanced mobile communication platform and integrating this platform into the EAM suite of IT applications and the GIS (hereafter referred to as the Mobility Integration project), is the subject of this business case.

The remainder of this business case outlines the rationale for the Mobility Integration project, the objectives, scope and timing of the project, the economic value of the project and the consistency of the project with the NGR.

1.4. Rationale for the Mobility Integration project

1.4.1. Deficiencies in the existing processes and systems

AGN's Victorian and Albury network businesses currently rely on paper-based manual processes for the majority of their field based activities, including work management, health, safety and environment (HSE) management, technical work procedures and asset information collation. The use of these processes is costly and inefficient because information must be entered manually into numerous systems, which can result in data integrity issues, double handling of information and delays in the information becoming available.

The use of these processes also exposes AGN to a range of safety, operational, customer and financial risks as highlighted in Table 1.3, which shows that the untreated risk associated with the current paper-based manual processes is Moderate.

The continued use of these processes exposes AGN to the following risk consequences*:*

- *Health and Safety* - operational staff are unable to report on and manage safety incidents efficiently and effectively due to manual and paper-based processes. Other risks include insufficient safety information (such as relevant asset hazard information) being available in real time to field crew and lack of a pictorial representation of the asset can increase the likelihood of a safety incident.
- *Operational* - the lack of an integrated Mobility system results in inefficient work order processing, an inability to make spatial and logical queries, and operational risks of errors in manual data processes compared to mobile communications.
- *Customer* - as customer service demands increase, the lack of mobility devices for field personnel as well as restricted functionality, will likely result in AGN failing to meet customer expectations, whether through access to real time information on scheduled work, reduced timeframes for restoration works or inadequate visibility on the status of work. It may also

mean that AGN has to make Guaranteed Service Level (GSL) payments to customers if these consequences result in longer outage restoration times.

- *Financial* - the Health and Safety, Operational and Customer risk consequences outlined above could give rise to considerable financial consequences, for example compensation claims or GSL payments.

Table 1.3: Risk Rating

Risk Area	Untreated Risk Level
Health and Safety	Moderate
Environment	Negligible
Operational	Moderate
Customers	Moderate
Reputation	Negligible
Compliance	Low
Financial	Moderate
Untreated Risk Rating	**Moderate**

The continued application of paper-based manual processes also means that AGN is constrained in its ability to:

- realise the full benefits of the EAM system and the GIS, including more efficient resource management, resource location and response times;
- improve service delivery to customers through faster response times and providing real-time status updates on network outages and service requests;
- improve the safety of services by, for example, providing field crews with real time safety related information and up to date asset data through the Dial Before You Dig (DBYD) service and employees and contractors' mobile devices;
- improve the integrity of services through more informed decision making and reductions in operational errors from manual processing of data;
- comply with regulatory and market obligations through the timely reporting of accurate information;
- optimise AGN's risk-based approach to asset management with existing risk mitigation measures underpinned by additional 'effective analysis' as the ESV is now requiring of Victorian gas distributors (see Box 1.1); and
- avoid future cost increases through optimised mobile workforce management and improved decision making.

Box 0.1: ESV's expectations for a risk-based approach to asset management

In the 2014/15 Gas & Pipeline Infrastructure (GPI) Safety Management Report[10], the ESV noted that it expects Victorian distributors to start employing more of a risk based approach to asset management and that it expects to see:

> *"more evidence that risk-based approaches are being adopted, implemented and sufficiently resourced, and that risk-mitigation requirements are being driven by effective analysis."*[11]

In doing so, the ESV made the following observations:

> *"Pipeline risk is dynamic, increasing as assets age and corrode and as the types of activities in and around pipelines and their easements change."*[12]

> *"Empirical evidence also suggests that most high-impact, low-probability incidents occur because of the aligned failures or partial failures of a number of physical and procedural barriers (threat barriers) designed to prevent injury or damage to people, property and the environment, rather than because of an isolated major failure."*[13]

> *"In 2013/14, incidents damaging mains and services peaked and there has been no level of improvement to these statistics that demonstrates asset owners are understanding and identifying the root cause of these incidents and sufficiently mitigating the risk to infrastructure and potential harm to people."*[14]

> *"Third-party interference and structural failures have the potential to cause high consequence events involving death and significant supply interruption…… the number of hits on mains and services (causing damage and gas escape) remains excessively high."*[15]

> *"Proposed land development and third-party works around pipelines need to not only be accurately captured but also competently assessed…"*[16]

> *"…safety framework documentation complying with pre-existing standards is no longer acceptable….. an increased emphasis on a risk-based approach to managing and operating assets is now required."*[17]

In order to meet the ESV's increased expectations around the risk-based approach to asset management and operation, accurate data and appropriate data analysis tools are required to optimise effective asset monitoring, analysis and risk management.

The continued use of these processes will also mean that AGN will fall further behind its peers who have already invested in mobility solutions and real-time information provision. The service providers that AGN is aware have already invested in mobility and are continuing to invest in this area include SA Power Networks (SAPN), Ergon Energy, Energex, AusNet Services (gas), Multinet, United Energy and Jemena (gas and electricity). As far as AGN can ascertain from the relevant regulatory determinations, the AER has approved the proposed expenditure by each of these service providers on mobility solutions[18]. AGN's Victorian and Albury networks are therefore

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10 Energy Safe Victoria, *"GPI Safety Management Report 2014/15 – Executive Briefing"*, June 2016
11 Energy Safe Victoria, *"GPI Safety Management Report 2014/15 – Executive Briefing"*, June 2016, pg.5.
12 Energy Safe Victoria, *"GPI Safety Management Report 2014/15 – Executive Briefing"*, June 2016, pg.4.
13 Energy Safe Victoria, *"GPI Safety Management Report 2014/15 – Executive Briefing"*, June 2016, pg. 4.
14 Energy Safe Victoria, *"GPI Safety Management Report 2014/15 – Executive Briefing"*, June 2016, pg. 5.
15 Energy Safe Victoria, *"GPI Safety Management Report 2014/15 – Executive Briefing"*, June 2016, pg. 5.
16 Energy Safe Victoria, *"GPI Safety Management Report 2014/15 – Executive Briefing"*, June 2016, pg. 5.
17 Energy Safe Victoria, *"GPI Safety Management Report 2014/15 – Executive Briefing"*, June 2016, pg. 8.
18 AER, "Final Decision: SAPN determination 2015-16 to 2019-20", Attachment 6, pg. 6-120, AER, "Draft Decision: JGN Access Arrangement 2015-20", November 2014, Attachment 6, pg. 6-42, AER, "Preliminary Decision: Jemena distribution determination 2016 to 2020", October 2015, Attachment 6, pg. 6-94, AER, "Final Decision: Ergon Energy determination 2015-16 to 2019-20", October 2015, Attachment 6, pg. 6-120 and AER, "Final Decision: Energex determination 2015-16 to 2019-20", October 2015, Attachment 6, pg. 6-10. The AER has also previously approved the allowances sought by AusNet services (gas) and Multinet for mobility related projects.

behind many of its peers on the mobility journey and will fall behind AGN's South Australian network if this business case is not approved.

1.4.2. Opportunities for Mobility solutions

There are a number of opportunities for mobility solutions in the Victorian and Albury networks, including to:

- improve work management through the EAM system;
- reduce health and safety risks;
- reduce the level of effort involved in complying with regulatory obligations; and
- address a number of other inefficiencies and limitations that AGN has identified.

Further detail on these opportunities is provided below.

1.4.2.1. Improved work management through the EAM system

The EAM system was implemented in Victoria and Albury in August 2015 and has introduced a number of new work management processes into the Victorian and Albury networks, including discrete work orders for jobs (over 170,000 jobs per annum), purchase orders linked to individual jobs, stringent work and financial approval processes, recipient created tax invoices and linked inventory and purchasing processes. The design of the EAM system was developed in accordance with good practice to ensure appropriate asset management and data capture required for critical asset management decision making. The introduction of this control and linkages to discrete jobs out of a single system has resulted in purchasing and payments becoming linked to the completion of work. The automated nature of the EAM system has also introduced specific business rules that require specific data at particular points in the work order life cycle to ensure work is planned, scheduled, dispatched, completed and data entered seamlessly.

Since implementing the EAM system it has become clear that using paper-based processes in conjunction with the EAM system is giving rise to a range of significant issues and costs due to incorrect field data capture, data entry errors and delays in the receipt of information from the field. Specifically, the paper-based processes are introducing inefficiencies and additional costs into the business as additional data capture requirements add to the effort required for data entry, validation and storage. Some of the specific problems that have arisen since the EAM system was introduced include:

- contractors not being paid due to incorrect data being provided and/or entered through the paper-based process;
- work information, such as labour costs, and asset information not being captured due to the requirement to focus on critical processing to ensure suppliers are paid; and
- inventory not being purchased in a timely manner due to timing issues in receipt of field data.

Evidence is also surfacing of data entry errors requiring additional effort in manual correction, paperwork going missing and having to rely on chasing-up carbon copies of missing paperwork.

In this case, implementing the Mobility Integration project is critical to ensuring that:

- accurate and timely data is provided by over 30 internal field staff and 360 contractors for the 170,000 work orders that are managed by the EAM system;
- work is managed effectively within the business; and
- contractors' payments are correct and timely and inventory is purchased in a timely manner.

The Mobility Integration project will also enable the current data capture costs associated with the EAM project to be reduced and the anticipated future increases in these costs to be avoided. These costs have emerged after the implementation of the EAM project (i.e. post August 2015) due to increased data capture requirements and the Mobility Integration project will reduce costs currently incurred (i.e. generate cost savings whilst assisting to reduce anticipated future opex cost increases (i.e. cost avoidance). See Appendix C for more detail on the cost savings and cost avoidance benefits of the Mobility Integration project.

It is worth noting in this context that if the Mobility Integration project does not proceed, then the costs of operating the Victorian and Albury networks will increase by approximately $311 ($000, 2016) in the next AA period because AGN will have to employ additional resources to deal with the additional data entry and validation requirements as a result of additional data capture requirements from organic growth as set out in Section **Error! Reference source not found.** - **Error! Reference source not found.**.

1.4.2.2. Reduced Health and Safety risks

AGN has a robust HSE Management system in place, which requires the following type of information to be recorded and stored for future reference for audit purposes and in the event of a HSE incident:

- Job Hazard & Environment Analysis (JHEA);
- Site Traffic Management Plans; and
- Hazardous Task Permits.

Field staff are also required to have ready access to current safety documentation such as Safe Work Method Statements (SWMS), technical work procedures, plant and equipment Safe Operating Procedures and Material Safety Data Sheets (MSDS) and asset maps and photographs.

Continuing to manage this safety-related information through paper-based processes is exposing AGN’s staff and contractors to a number of health and safety risks because the information can quickly become outdated and contractors/staff may not have access to the required safety documents when on site.

The Mobility Integration project in this case will address the health and safety related risks outlined above, by ensuring that:

- safety sheets are available for entry in the field and can be efficiently stored following completion;
- up-to-date maps and asset details/photographs are available in the field;
- up-to-date work instructions are available to staff when working on assets in the field; and
- field crew are able to update asset conditions in real time.

1.4.2.3. Reduced effort required to comply with regulatory obligations

AGN is required to comply with a number of significant regulatory obligations under the Health and Safety legislation, technical regulations, the NGL, NGR, Retail Market Procedures and the National Energy Retail Law and Rules. At present, AGN is required to provide over multiple reports to various regulatory bodies on a monthly, quarterly or annual basis. While there are robust processes in place to capture and validate the data required for this reporting, the data gathering processes are highly manual, require ongoing manual validation checks and balances and can impact on the timeliness and integrity of the reporting.

This Mobility Integration project in this case will enable:

- data validation to occur in the field before being stored in Enterprise systems;
- up-to-date data to be input into relevant systems to facilitate timely regulatory reporting; and
- manual data gathering and data validation processes to be avoided.

1.4.2.4. Other opportunities for Mobility solutions

Further detail on how the Mobility Integration project would address some of the other inefficiencies and limitations that AGN has identified with the current paper-based processes is provided below:

- *Data entry* - The Victorian and Albury networks currently rely on paper-based processes to capture field data, which is then manually entered into various systems, such as the EAM system, GIS or Human Resources (HR). The Mobility Integration project will significantly reduce manual data entry effort as the data is captured directly in the relevant system and subsequently results in tangible benefits. Mobile field data capture will also bring AGN in line with its peers.
- *Data integrity* - Due to the current paper-based processes to capture field data, there are significant manual data validation and error handling processes required to ensure data integrity. The Mobility Integration project will reduce the validation, error handling and correction effort as validation processes are implemented on mobile devices and field data entry processes are more tightly controlled through mobile application design. This will, in turn, result in tangible benefits in the form of avoided costs. Data validation at the time of capture will bring AGN in line with its industry peers.
- *Efficient workforce management* - The Mobility Integration project will provide field crews with required work information in the field, resulting in increased work efficiency. An example of a tangible cost saving from this improved effectiveness is the ability to have crews starting from home as they can receive their work directly to their mobile device, rather than spending time travelling to the depot. The provision of real time information to the field crew will also increase their effectiveness in dealing with service requests through an understanding of the assets they are attending and the associated customer requirements. This also results in improved customer service and staff collaboration and safety.
- *Customer service* - The Mobility Integration project will improve the accuracy and quality of customer information and improve service delivery to customers in a number of ways. For example, the provision of real time information to the field crew on the customer's request and the status of any work that has already been done will improve the customer's experience and avoid any doubling up of work. The ability to assign field crews that are in closest proximity will also ensure field crews can respond rapidly to emergency work in accordance with our regulatory obligations. The project will also enable accurate and timely information to be provided to customers on outages and the status of their service requests. Real time data gathering and associated customer service benefits will bring AGN in line with our industry peers. Additionally, given the nature of this project, AGN considers it to be consistent with the findings from our stakeholder engagement program in which customers indicated that they[19] "would like to access more information from AGN and favour digital channels".

  This improved customer service offering is not achievable utilising the existing paper-based processes because they do not facilitate the capture and provision of 'real-time' information.

[19] Deloitte, *"Australian Gas Networks Customer Insights Report, Victorian and Albury Stakeholder Engagement Program"*, May 2016.

- *Safety* - The implementation of the mobility solution will enhance network health and safety from a public and staff perspective. Public safety will be improved through improved response to emergencies and access to accurate asset data such as DBYD information. Employee, contractor and public safety will be improved through worker access to improved asset data, streamlined safety tools and processes and live access to corporate knowledge, such as latest version of technical work instructions and training manuals and asset descriptions/photographs.
- *Maintaining the security and integrity of services* - The Mobility Integration project will facilitate the gathering of data that can be utilised for improved decision making through use of the Business Intelligence (BI) tools. While categorised as an intangible benefit due to the requirement for use of the BI tools, the ability to gather this data is critical to optimising asset decision-making (thus addressing the ESV expectations for improved asset risk management driven by effective analysis) and improving the integrity of the services. There will also be less operational errors from manual processing of data, which will improve the integrity of the services provided. Controls to maintain the security of corporate and customer data will be maintained to address risks of unauthorised data interception and/or manipulation.
- *Provide the foundation for improved decision-making* - The Mobility Integration project will provide field crews with real time access to asset performance history and the ability to update asset conditions. This functionality will enhance asset management decision-making in the field and more broadly across the business, including targeted maintenance and asset replacement activities to maintain asset integrity. The provision of real time information to the field crew will also increase their effectiveness in dealing with service requests through an understanding of the assets they are attending and the associated customer requirements. This will, in turn provide for improvements in productivity, utilisation and collaboration.

1.4.3. Summary

As the preceding discussion reveals, the current manual paper-based processes are:

- costly and inefficient;
- exposing AGN to a range of safety, operational, customer and financial related risks; and
- limiting AGN's ability to achieve further:
  - efficiencies in the field and across the business; and
  - improvements in customer service delivery, the safety and integrity of services and compliance with regulatory obligations.

It is for these reasons that AGN, like many of its peers, is proposing to invest in mobility solutions and real-time information provision through the Mobility Integration project.

As highlighted in the detailed Risk Assessment set out in Appendix A, the implementation of this project tools will reduce the overall risk rating from Moderate to Low if the Mobility Integration project is implemented.

1.5. Project objectives, scope and timing

1.5.1. Project objectives

The overarching objectives of the Mobility Integration project are to:

1. enhance the mobile communications platform to enable field mobility within the workforce;
2. integrate the enhanced mobile communications into the EAM system (Maximo) and GIS; and
3. implement prudent and efficient end to end business processes that automate enterprise asset management and GIS functionality through mobility.

Apart from providing for greater efficiency in the field and across the business, the Mobility Integration project is also expected to result in improvements in customer service delivery (for example, by reducing response times and providing accurate and timely information on outages and service requests), the safety and integrity of services and compliance with regulatory obligations.

1.5.2. Project scope

The project elements, which are based on the Enterprise-wide and state-specific requirements for the implementation, are as follows:

- mobile device management application design and implementation;
- integration with existing Enterprise systems (e.g. Asset Management, GIS, Payroll, HSE & Document Management);
- mobile works management forms (such as work orders, timesheets, audit forms and HSE checklists);
- mobile device refresh;
- streamlining of business processes;
- change management, including rollout of mobile solutions to contractors; and
- mobile device and application training.

The Enterprise-wide implementation will take approximately four years to allow for new capabilities to be progressively rolled out to different work groups. On completion of this project, AGN's Victorian and Albury networks will be supported by a suite of mobility applications that are fully integrated into key Enterprise IT systems, such as the EAM system, GIS, HSE platform, payroll and document management.

1.5.3. Timing and deliverability of the project

Work on the Mobility Integration project is due to commence in 2017 and be completed by 2022. While there will be some overlap between this project and other elements of the IT Plan, AGN's IT services provider, APA Group (APA), has a proven track record in delivering significant IT projects for AGN and its own business on time and within budget.

For example, in the current AA period APA has implemented the Enterprise systems for AGN (e.g. Oracle Financials, MnB, EAM, DBYD and a Data Centre) and a number of other significant IT projects for other areas of its business (e.g. SCADA Upgrades, GIS Implementations and Transmission Market grid services). APA's ability to implement all of these projects on time and within budget reflects its prudent, efficient and structured approach to implementing significant IT projects. It also clearly demonstrates APA's capability to implement the Mobility Integration project in accordance with the timing outlined above and to deliver the expected benefits of the project.

1.6. Economic value of the Mobility Integration Project (Rule 79(2)(a))

As the preceding discussion highlights, expenditure on the Mobility Integration project is justifiable under rule 79(2)(c) because it is necessary to maintain and improve the safety of services (rule 79(2)(c)(i)), maintain the integrity of services (rule 79(2)(c)(ii)) and comply with regulatory obligations (rule 79(2)(c)(iii)). It can also be justified under rule 79(2)(a), because as the analysis that follows shows, the overall economic value of the Mobility Integration project is positive (i.e. the present value of the project's benefits outweighs the project's costs over an 11 year period).

Further detail on the cost-benefit analysis that AGN has carried out and the assumptions underlying this analysis is provided below.

1.6.1. Cost / benefit assessment

Table 1.5 sets out the assumed profile of the Mobility Integration project's costs and benefits and the project's net present value (NPV), which has been calculated on the basis of the following assumptions:

- *Measurement period* - A 10 year period has been used to measure the benefits associated with this project, which reflects the ongoing and long-term nature of the project's benefits.
- *Project benefits ($000, 2016)* - The project benefits consist of a mix of tangible and intangible benefits, with the tangible benefits, detailed in Appendix C, including avoided costs and cost savings while the intangible benefits include the safety, customer service, compliance and decision making benefits described in Section 1.4.2.4 and summarised in Section **Error! Reference source not found.**. These benefits are also categorized as Opex or Capex benefits based on assumptions related to work order volume. The assumptions AGN has made when quantifying these benefits are set out in Appendix C, but it is worth noting that it has only been possible to quantify the tangible benefits. The benefits in Appendix C and the NPV therefore understate the economic value of the project.
- *Capex ($000, 2016)* - The capex in the next AA period reflects the cost of implementing the Mobility Integration project. In subsequent AA periods, the proposed capex includes the costs of ongoing renewals of newly implemented Mobility Integration platform, estimated at $200.0 ($000, 2016) every two years, which is based on the same assumptions that AGN used for the Applications Renewal business case (V47). It is worth noting that while the costs of the Mobility Integration platform renewals have been included in the NPV analysis, it is not included in the allowance being sought for this project or V46 Applications Renewal business case because these costs will only commence in the following (2023 to 2027) AA period. It is also worth noting that these costs are different from the annual Field Data / Mobility upgrade costs included in the V46 Applications Renewal which are related to AGN's existing mobile technology.
- *Discount rate* - a discount rate of 3.14%, which is AGN's proposed real pre-tax Weighted Average Cost of Capital (WACC) for the next AA period.

As the final row in Table 1.5 shows, the Mobility Integration project is expected to yield a positive economic value of approximately $3,708 ($000, 2016) over a 10 year period from the year in which benefits are first realised and is therefore justifiable under Rule 79(2)(a) of the NGR.

Further detail on the benefits and costs of this project is provided in the following sections.

Table 1.5: NPV Calculation ($000, 2016)

Year since start		0	1	2	3	4	5	6	7	8	9	10
Calendar Year	**Total**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Costs												
Total capex	**12,188.1**	**1,207.2**	**2,564.6**	**3,167.5**	**3,229.4**	**1,419.4**	**-**	**200.0**	**-**	**200.0**	**-**	**200.0**
Discounted capex	**10,992.9**	**1,170.4**	**2,410.9**	**2,886.9**	**2,853.7**	**1,216.1**	**-**	**161.1**	**-**	**151.4**	**-**	**142.3**
Benefits												
Cost avoidance												
Organic Growth Data Requirements	2,095.5	-	-	22.3	45.2	128.1	186.3	236.4	288.0	341.1	395.9	452.3
Total cost avoidance	**2,095.5**	**-**	-	22.3	45.2	128.1	186.3	236.4	288.0	341.1	395.9	452.3
Total Discounted cost avoidance	**1,610.7**	**-**	**-**	**20.3**	**39.9**	**109.8**	**154.7**	**190.4**	**224.9**	**258.3**	**290.6**	**321.9**
Cost savings												
Work order field completion	4,335.0	-	255.0	255.0	255.0	510.0	510.0	510.0	510.0	510.0	510.0	510.0
Data Validation	2,125.0	-	125.0	125.0	125.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0
Work order data entry	4,420.0	-	260.0	260.0	260.0	520.0	520.0	520.0	520.0	520.0	520.0	520.0
Safety documents	1,530.0	-	-	102.0	102.0	102.0	204.0	204.0	204.0	204.0	204.0	204.0
Filing & Storage	585.0	-	-	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Timesheet data entry	480.0	-	-	-	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
Work procedure printing	765.0	-	-	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0
Reduced depot trips	2,134.1	-	-	-	74.9	74.9	187.2	299.5	374.4	374.4	374.4	374.4
Total cost savings	**16,374.1**	**-**	**640.0**	**892.0**	**1,026.9**	**1,666.9**	**1,881.2**	**1,993.5**	**2,068.4**	**2,068.4**	**2,068.4**	**2,068.4**
Discounted cost savings	**13,099.0**	**-**	601.6	813.0	907.4	1,428.1	1,562.7	1,605.6	1,615.2	1,566.0	1,518.3	1,472.1
Total benefits	**18,469.6**	**-**	**640.0**	**914.3**	**1,072.1**	**1,795.0**	**2,067.5**	**2,229.9**	**2,356.4**	**2,409.5**	**2,464.3**	**2,520.7**
Total discounted benefits	**14,700.8**	-	**601.6**	**833.3**	**947.4**	**1,537.9**	**1,717.4**	**1,795.9**	**1,840.0**	**1,824.3**	**1,808.9**	**1,794.0**
Total												
Discounted costs	10,992.9	1,170.4	2,410.9	2,886.9	2,853.7	1,216.1	-	161.1	-	151.4	-	142.3
Discounted benefits	14,700.8	-	601.6	833.3	947.4	1,537.9	1,717.4	1,795.9	1,840.0	1,824.3	1,808.9	1,794.0
NPV	**3,707.9**	**(1,170.4)**	**(1,809.2)**	**(2,053.6)**	**(1,906.4)**	**321.8**	**1,717.4**	**1,634.9**	**1,840.0**	**1,672.8**	**1,808.9**	**1,651.6**
Does Expenditure Satisfy Rule 79(2)(a)?	**Yes**											

1.6.2. Benefits

The Mobility Integration project will yield a number of tangible and intangible benefits, as outlined in Section 1.4.2 and summarised below.

1.6.2.1. Tangible benefits

The tangible benefits include cost savings and costs avoided as a result of:

- reductions in manual data entry, data validation, printing, filing and storage; and
- the availability of corporate systems in the field and appropriate data validation metrics, which will result in improvements in what would otherwise be non-productive field time.

Specifically, the tangible benefits of the Mobility Integration project include:

- *Cost savings* - The cost savings arise from the removal of existing paper-based manual systems and processes. These savings are expected to affect a range of activities including work order data entry (EAM and non EAM related entry), timesheets, work procedure printing, the completion of safety documentation and trips to the depot. These savings also relate to both operating expenditure and capital expenditure, based on work order processing volumes. Generally, there are equal volumes of opex related work orders (such as leak repairs, preventative maintenance and network operations) compared to capex related work orders (such as meter changes, new connections and mains replacement). The total value of cost savings over the first 10 years in which benefits are realised is estimated to be $16,374.1 ($000, 2016), which in present value terms is equal to $13,099 ($000, 2016). Of these cost savings, $9,102.0 ($000, 2016) relate to Opex savings and $7,272.0 ($000, 2016) relate to Capex savings.
- *Avoided costs* - The costs avoided by the Mobility Integration project reflect the "do nothing" approach and include work order field completion, data validation, filing and storage costs associated with the new EAM system. The total value of avoided costs over the first 10 years in which benefits are realised is estimated to be $2,095.5 ($000, 2016), which in present value terms is equal to $1,610.7 ($000, 2016).

As discussed in Section 1.4.2.1, a significant part of the cost savings and cost avoidance benefits of the Mobility Integration project are due to reduced or avoided data capture costs associated with the EAM project. These costs have emerged after the implementation of the EAM project (i.e. post August 2015) and some of these costs (specifically, work order data entry costs) are being currently incurred and as such have been classified as cost savings, whilst the reduction in the anticipated future opex cost increases has been classified as cost avoidance.

Appendix C provides further detail on the nature and value of these tangible benefits and the assumptions AGN has made when estimating their value.

1.6.2.2. Intangible benefits

The key intangible benefits of the Mobility Integration project are outlined below:

- *Data Volumes* – The Victorian and Albury networks currently capture limited data in the field due to the cost prohibitive nature of the existing paper based processes. The EAM project has been designed to capture more data about work on assets, as well as capturing asset and financial data at a detailed job level. This will result in significantly more data being captured in the field and will enable improved asset management decision-making, as well as improving efficiencies around reporting obligations. The benefits of the additional data have been captured within the EAM Project benefits, without reflecting the significant increased costs associated with capturing this data utilising existing paper-based processes. These increased costs are due to additional time to capture data in the field using paper processes as well as subsequent data entry, checking and correction of the additional data. The Mobility Integration project will enable these increased costs to be avoided. The improvements in field data and increased data volumes will also enable the business to more effectively leverage the benefits of the Business Intelligence toolset as discussed in the IT Program of Work and detailed further in the Business Intelligence business case (V47).

- *Technical, Regulatory and Legislative Compliance Obligations* – The Victorian and Albury networks have a suite of management systems implemented to ensure compliance with a variety of technical, regulatory and legislative obligations. These obligations include Health & Safety legislation, technical regulations and regulatory requirements such as the NGL, the NGR, Retail Market Procedures, the National Energy Retail Law and Rules and the ESV's requirements. These management systems are supported by the related IT systems, such as the Asset Management System, GIS and HR systems to provide relevant information to meet these compliance obligations. Improvements in the timing and integrity of data will also streamline reporting to ensure compliance obligations are met in a timely manner and reported appropriately.
- *Health & Safety* - The implementation of the mobility solution will enhance network health and safety from a public and employee perspective. Public safety will be improved through improved response to emergencies and access to accurate asset data such as DBYD information. Employee, public and contractor safety will be improved through worker access to improved asset data, streamlined safety tools and processes and live access to corporate knowledge, such as latest version of technical work instructions and asset descriptions/photographs. Field workers will also be able to directly update asset conditions in Maximo where required. Improved asset data will also enhance asset management decision-making, including targeted maintenance and asset replacement activities to maintain asset integrity.

1.6.3. Forecast costs

1.6.3.1. Costing methodology

Mobility Integration is a national project. The total project cost has therefore been estimated on the basis of the work that is needed to be carried out across all Australian jurisdictions that AGN operates in. The approach that AGN has used to estimate the total project costs for the Mobility Integration project is the same as the approach that it used to estimate the costs of the South Australian component of the Mobility Integration project (which has been recently approved by the AER in its Final Decision) and is outlined below:

The approach that AGN has used to estimate the total project costs for the Mobility Integration project and its proposed approach to carrying out the work is outlined below:

- AGN utilises an industry standard Business & Technology (B&T) Project Methodology, which is managed through formal governance. This B&T Methodology divides the projects into key stages – concept, develop, plan, deliver and close. Each stage consists of key tasks and activities to ensure the consistency and standardisation across projects. The project methodology is outlined in Appendix D.
- To ensure project estimates are developed in consistent manner, AGN utilises an Estimation Tool, which is aligned with the B&T Project Methodology. This estimation tool has been used to forecast the work and cost estimates for the application upgrade program of work. This

estimation tool utilises historic figures from the current AA period for resource work effort estimates. All historic figures are checked for reasonableness to ensure any changes to the way historical projects were carried out were taken into account. The work estimates are based on a complexity matrix tool, which uses a series of questions to categorise projects into simple, medium and complex.

- The material and direct labour costs, and applicable planning, design and commissioning charges, are based on historic actual costs of similar projects and on vendor quotes subject to a competitive tendering process in accordance with the APA Procurement policy and guidelines20. Resource Unit Costs (both internal and external) are based on AGN's Project Management Office (PMO) research, where actual placement costs have been used based on historical project resources and current resourcing rates (2016).
- The historic figures and work effort estimates are used as inputs into the final estimates, which are subject to stringent review and endorsement by members of the IT Estimates Review Committee. The work effort, cost and timing of projects are monitored throughout the project lifecycle to ensure on time and on budget delivery.
- When implementing the project, AGN will use a formalised Project Methodology and utilise a combination of internal and external resources (through vendors and trusted recruitment agencies) to deliver the program of work to ensure that services are carried out in a prudent and efficient manner. The Project Methodology is outlined in Appendix D and provides a consistent, standard and quality assured project implementation framework. The PMO will provide guidance and governance to the project, ensuring that the work is carried out in a prudent and efficient manner.

A key principle that has been employed when developing these estimates is that enterprise economies of scale achieved through utilising standardised business processes, data models, data migration techniques and existing hardware platforms should be reflected in the estimate (see the IT Plan for more detail).

The portion of these costs that should be attributed to AGN's Victorian and Albury networks has been based on the proportion of customers supplied by these network businesses (51.35% and 1.79%, respectively as at 31 December 2015).

The Victorian and Albury networks' share of the total cost of the Mobility Integration project is estimated to be $11,588.1 ($000, 2016) capex. Under the National Mobility Strategy and Roadmap, the projects in Victoria, Albury and South Australia are scheduled to commence simultaneously in July 2017, with $1,207.2 ($000, 2016) of the $11,558.1 ($000, 2016) to be spent in the current AA period. The remaining $10,380.9 ($000, 2016) will be spent in the next AA period.

1.6.3.2. Forecast Cost Breakdown for the next AA period

A breakdown of the total project cost by project phase is provided in Appendix B, while the tables below provide a summary of the foreacast costs over the next AA period.

[20] Available upon request.

Table 1.6: Capex / Opex Split ($000, 2016)

	2018	2019	2020	2021	2022	Total
Capex	2,564.6	3,167.5	3,229.4	1,419.4	-	**10,380.9**
Opex	-	-	-	-	-	**-**
Total	**2,564.6**	**3,167.5**	**3,229.4**	**1,419.4**	**-**	**10,380.9**

Note: Totals may not exactly match the sum of individual costs due to rounding.

Table 1.7: Project Cost Estimate, By Cost, Capex ($000, 2016)

	2018	2019	2020	2021	2022	Total
Direct Labour	1,243.7	1,838.3	1,900.2	849.8	-	**5,831.9**
Contracted Labour	1,197.6	1,147.5	1,147.5	491.8	-	**3,984.4**
Hardware, Software and Maintenance	57.4	133.9	133.9	57.4	-	**382.5**
Travel, Sundry, Other	66.0	47.8	47.8	20.5	-	**182.1**
Total	**2,564.6**	**3,167.5**	**3,229.4**	**1,419.4**	**-**	**10,380.9**

Note: Totals may not exactly match the sum of individual costs due to rounding.

Table 1.8: Capex Split between Victoria and Albury ($000, 2016)

	2018	2019	2020	2021	2022	Total
Capex – Victoria	2,478.3	3,060.8	3,120.6	1,371.6	-	**10,031.3**
Capex - Albury	86.4	106.7	108.8	47.8	-	**349.7**
Total	**2,564.6**	**3,167.5**	**3,229.4**	**1,419.4**	**-**	**10,380.9**

Note: Totals may not exactly match the sum of individual costs due to rounding.

Further detail on how the labour and vendor cost components of this forecast have been developed is provided below.

1.6.3.3. Labour requirements

Implementing the Mobility Integration Project will require a mix of both internal and external IT resources.

An Enterprise Project cost estimate for the Mobility Integration project has been developed using the standard IT Project estimating methodology as outlined in the Appendix D. The internal resource costs have been estimated from the bottom up by breaking the project into stages and tasks and considering the requirements (skill set and time) for each task. Where additional specialist internal resources need to be brought to the project, the hourly rates are differentiated by resource types and are based on the current market rates for these roles. The internal labour costs include the following:

- internal project management;

- change management;
- business process re-design;
- system integration;
- business analyst and Subject Matter Expert (SME) support; and
- training.

1.6.3.4. Vendor costs

External vendor cost estimates have been provided by IBM based on their previous experience in implementing mobility integration projects into their Maximo application. These cost estimates include the following:

- external project management;
- application design;
- system build; and
- system testing and implementation.

1.7. Consistency with the National Gas Rules

As the analysis in the preceding section shows, the Mobility Integration project is justified under rule 79(2)(a) of the NGR because the overall economic value of the project is positive. The project is also justified under rule 79(2)(c) because it is necessary to:

- *Maintain and improve the safety of services (rule 79(2)(c)(i))* - The Mobility Integration project offers a number of opportunities to reduce health and safety risk to both the workforce and to the public as previously discussed.
- *Maintain the integrity of services (rule 79(2)(c)(ii))* - The Mobility Integration project will allow more accurate data to be extracted and utilised for improved decision making.
- *Comply with a regulatory obligation or requirement (rule 79(2)(c)(iii))* - The Mobility Integration project will overcome the delays in service provision and meeting regulatory obligations and will also ensure that data is available to demonstrate compliance. The project will also enable AGN to optimise the existing risk-based approaches to asset management that the ESV is now emphasising.

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN also considers the forecast capex for this project to be:

- *Prudent* – The expenditure is necessary in order to maintain the security and integrity of services and comply with regulatory obligations and requirements and is of a nature that a prudent service provider would incur.
- *Efficient* – The Mobility Integration Project is cost effective and will enable AGN to improve operational efficiency and minimise the risk to human health and safety, customer and business interruptions and corresponding adverse financial and reputation impacts. The manner in which AGN proposes to carry out this project and the governance processes it has in place (see the IT Investment Plan), will also ensure that costs are efficiently incurred. The expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.

- *Consistent with accepted good industry practice* – It is good practice to seek to continue to develop service levels in-line with opportunities from new technology. This is demonstrated by recent applications by other network businesses in both the gas and electricity distribution sectors for implementation of mobility applications.[21] It is also worth noting that unlike many of its gas and electricity distribution counterparts, including SA Power Networks (SAPN), Ergon Energy, Energex, AusNet Services (gas), Multinet, United Energy and Jemena (gas and electricity)[22], who started on the mobility journey five or more years ago as approved by the AER, AGN is yet to invest in mobility solutions that integrate into enterprise applications. AGN is therefore behind many of its peers in this area.
- *To achieve the lowest sustainable cost of delivering pipeline services* – The integration of mobility solutions will reduce manual processing and costs and will assist with the provision of improved data for decision making. It will therefore contribute to the achievement of the lowest sustainable cost of delivering pipeline services to our customers.

The proposed expenditure on the Mobility Integration project can therefore be viewed as conforming capex under rule 79 of the NGR.

[21] Examples include SA Power Networks IT Field Force Mobility Business Case submitted as part of their 2014 proposal for their determination covering 2015-20. The AER's November 2014 draft determination for Jemena's Gas network in NSW supported their adoption of a field mobility solution

[22] SAPN, "IT Field Force Mobility Business Case", 3 July 2015, Ergon Energy, "Forecast Expenditure Summary Information, Communication and Technology, 2015 to 2020", pg. 4, Energex, "ICT Services Expenditure, 2015-20 regulatory proposal", October 2014, pg. 5, AusNet Services, "Electricity Distribution Price Review 2011-2015 Regulatory Proposal", November 2009, pg. 158, Multinet, "Gas Access Arrangement Review January 2013-December 2017 AAI", 30 March 2012, pg. 85, Jemena Gas Networks, "2015-20 AAI, Appendix 6.3 IT Strategy and Asset Management Plan", June 2014, pg. 9, Jemena Electricity Networks, "2016-20 Electricity Distribution Price Review Regulatory Proposal", Attachment 7-3, 30 April 2015, pg. 87 and United Energy, "Capital Expenditure Overview – ICT, 30 April 2014", pg. 11.

Appendix A Risk Assessment

The risk assessment for all options considered in this business case has been carried out in accordance with the APA Group Risk Management Policy. The summary of the risk assessment for the untreated risk and residual risk (after the implementation of Mobility Integration project) is provided below.

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Option Risk
Risk Untreated (i.e. do nothing)	**Likelihood**	*Occasional*	*Rare*	*Occasional*	*Likely*	*Rare*	*Unlikely*	*Frequent*	**MODERATE**
	Consequence	*Medium*	*Insignificant*	*Minor*	*Minor*	*Insignificant*	*Minor*	*Minor*	
	Risk Level	*Moderate*	*Negligible*	*Low*	*Moderate*	*Negligible*	*Low*	*Moderate*	
Residual Risk (i.e. after Mobility Integration project is implemented)	**Likelihood**	*Unlikely*	*Rare*	*Unlikely*	*Unlikely*	*Rare*	*Unlikely*	*Unlikely*	**LOW**
	Consequence	*Medium*	*Insignificant*	*Minor*	*Minor*	*Insignificant*	*Minor*	*Minor*	
	Risk Level	*Low*	*Negligible*	*Low*	*Low*	*Negligible*	*Low*	*Low*	

The following provides a summary of key consequences by category impacted by this project, as per the APA Group Risk Management Policy:

- **Health and Safety:** Managing safety related information through paper-based processes is exposing AGN's staff and contractors to a number of health and safety risk consequences because the information can quickly become outdated and contractors/staff may not have access to the required safety documents when on site. Some other health and safety related risk consequences of the current processes include:

  a. Operational staff being unable to report on and manage safety incidents efficiently and effectively.

  b. Insufficient safety information (such as relevant asset hazard information) being available in real time to field crews.

  The Health and Safety risk levels will be reduced from Moderate to Low by the Mobility Integration project.

- **Customers:** The lack of mobility devices for field personnel as well as restricted functionality could lead to increased restoration times, especially if demand increases. This may lead to Guaranteed Service Level payments and reduced customer satisfaction due to longer outage restoration times. The Customers risk level will be reduced from Moderate to Low by the Mobility Integration project.

- **Financial:** The financial risk consequences include financial penalties for poor operational performance, e.g. compensation claims and GSL payments. In addition, each of the Health and Safety, Operational and Customer consequences may result in sizeable financial consequences. The Financial risk level will be reduced from Moderate to Low by the Mobility Integration project.

Appendix B Detailed Cost Estimate

The project cost breakdown by the project stage is provided below.

IT & ICT Procurement Estimations Template: B&T Projects		
Project Name:	Mobility Integration	
Project Complexity:	Complex	
Project Type:	Major Change	
Estimations Summary		
Total Project (end to end)	Effort (Days)	Total Cost
End to End Total	5,083	$ 11,588,098.43
Estimations by Project Stage		
Develop Stage Total	283	$ 407,088.85
Plan Stage Total	624	$ 2,007,212.16
Deliver Stage Total	4,071	$ 9,049,940.40
Close Stage Total	105	$ 123,857.01

Appendix C Mobility Integration Tangible Benefits

TABLE C.1: TANGIBLE BENEFITS

Benefit		Assumptions		2017	2018	2019	2020	2021	2022	AA Total	2023	2024	2025	2026	2027	10-year total	PV[23] of 10-year total
				Estimate of Benefit by Year ($000, 2016)													
Cost Avoidance[24]			**Type**														
Organic Growth	Work order data collation increases over the period where benefits are realised as organic growth in the network drives increased work orders	The Mobility Integration project will reduce effort associated with recording data from work, including work order field completion, supervisor data validation, work order data entry and safety document data recording. These avoided costs are based on the work order and safety document cost saving assumptions below and assuming a 3% organic growth rate in work per year	Opex	-	-	11.1	22.6	64.1	93.1	**190.9**	118.2	144.0	170.6	197.9	226.1	**1,047.7**	**805.4**
			Capex	-	-	11.1	22.6	64.1	93.1	**190.9**	118.2	144.0	170.6	197.9	226.1	**1,047.7**	**805.4**
Total			**Opex**	-	-	11.1	22.6	64.1	93.1	**190.9**	118.2	144.0	170.6	197.9	226.1	**1,047.7**	**805.4**
Total			**Capex**	-	-	11.1	22.6	64.1	93.1	**190.9**	118.2	144.0	170.6	197.9	226.1	**1,047.7**	**805.4**
Total Cost Avoidance			**Total**	-	-	22.3	45.2	128.1	186.3	**381.9**	236.4	288.0	341.1	395.9	452.3	**2,095.5**	**1,610.7**

[23] Present value of the benefits based on the same discount rate as that used in the NPV analysis.
[24] AGN's expenditure on these activities does not form part of its base year opex. The benefits are therefore considered an avoided cost.

Benefit		Assumptions	Type	2017	2018	2019	2020	2021	2022	AA Total	2023	2024	2025	2026	2027	10-year total	PV[23] of 10-year total
				Estimate of Benefit by Year ($000, 2016)													
Cost Savings			**Type**														
Work order field completion	Work order data collation has increased since the introduction of EAM because the new system requires information on asset data, work completion and purchase order data to be input.	The Mobility Integration project will reduce the data gathering efforts, which are assumed to require three minutes of effort per work order across approximately 170,000 work orders per annum (50% Capital related and 50% Opex related). The rate assumed for a field resource [redacted] The increased costs are assumed to progressively reduce as the project is rolled out into the business, starting with the high impact areas.	Opex	-	127.5	127.5	127.5	255.0	255.0	**892.5**	255.0	255.0	255.0	255.0	255.0	**2,167.5**	**1,745.3**
			Capex	-	127.5	127.5	127.5	255.0	255.0	**892.5**	255.0	255.0	255.0	255.0	255.0	**2,167.5**	**1,745.3**
Data validation	Current evidence suggests that 10-15% of the work order information collated through the EAM manual data gathering process require validation or error correction. This data relates to asset information such as incorrect meter change out information, purchase orders not claiming the correct service performed or incorrect labour/materials information. To ensure correct data is input into the system, this data needs to be validated or corrected prior to entry.	The Mobility Integration project will substantially reduce the data validation step because data will be entered directly from the field. The costs avoided in this case have been estimated assuming that data quality checks are carried out on 170,000 work orders per year and 20,000 (50% Capital related and 50% Opex related) require an average of 10 minutes effort to validate data or chase up errors. It is also assumed a Supervisor at a [redacted] is required to follow up on the errors given the complexity of the issues and the difficulty in physically locating work crews to clarify data on work orders. The avoided costs are assumed to progressively increase as the project is rolled out into the business (which will start in high impact areas). They also increase over time because without the project, more data would need to be validated as the number of work orders increase in response to organic network growth.	Opex	-	62.5	62.5	62.5	125.0	125.0	**437.5**	125.0	125.0	125.0	125.0	125.0	**1,062.5**	**855.5**
			Capex	-	62.5	62.5	62.5	125.0	125.0	**437.5**	125.0	125.0	125.0	125.0	125.0	**1,062.5**	**855.5**

Benefit		Assumptions		Estimate of Benefit by Year ($000, 2016) 2017	2018	2019	2020	2021	2022	AA Total	2023	2024	2025	2026	2027	10-year total	PV[23] of 10-year total
Work order data entry	Work order data entry is significant cost associated with the existing manual paper-based processes currently in place. The Mobility Integration will result in data being captured in the field and reduce the requirement for data entry resources.	It is assumed that there is a cost saving of [redacted] annum, based on additional resources required, following additional data capture requirements from EAM plus efficiencies gained in processing existing data (50% Capital related and 50% Opex related). The Opex portion of these costs has been included in the Base Year Opex and therefore are Cost Savings. These savings are progressively realised as additional functionality is rolled out in ongoing phases of the project.	Opex	-	130.0	130.0	130.0	260.0	260.0	**910.0**	260.0	260.0	260.0	260.0	260.0	**2,210.0**	**1,779.5**
			Capex	-	130.0	130.0	130.0	260.0	260.0	**910.0**	260.0	260.0	260.0	260.0	260.0	**2,210.0**	**1,779.5**
Safety documents	Field personnel are currently required to manually complete a range of safety documentation (e.g. JHEA, Traffic Management Plans and Work Permits). The	The estimated cost savings in this case assume that the 170,000 work orders (50% Capital related and 50% Opex related) completed in the field each year requires a JHEA to be completed and that the mobility solution results in a time saving of one minute per JHEA. It is also	Opex	-	-	51.0	51.0	51.0	102.0	**255.0**	102.0	102.0	102.0	102.0	102.0	**765.0**	**606.5**

Benefit		Assumptions		Estimate of Benefit by Year ($000, 2016)												10-year total	PV[23] of 10-year total
				2017	2018	2019	2020	2021	2022	AA Total	2023	2024	2025	2026	2027		
	completion of these documents will be included as a functionality of the mobility solution, which will enable more efficient recording of this information in the field.	assumed 5% of those work order require other safety documents, such as Traffic Management Plans or Permits, and that the mobility solution results in a time saving of approximately four minutes per document. These documents are generally completed by field crews at a cost [redacted] This functionality will roll out in the third year from the project commencement due to other functionality providing higher levels of benefits being rolled out earlier in the project.	Capex	-	-	51.0	51.0	51.0	102.0	**255.0**	102.0	102.0	102.0	102.0	102.0	**765.0**	**606.5**
Filing and storage	The increased data collation requirements of EAM have resulted in increased filing and storage by administrative staff.	The Mobility Integration project will result in a reduction in filing and storage costs. The cost savings will progressively increase as paper-based orders are removed. The cost savings are estimated at the equivalent of a full time employee (FTE) (at an average cost [redacted] FTE per annum and will start from Year 2 of the project as the relevant functionality is rolled out	Opex	-	-	65.0	65.0	65.0	65.0	**260.0**	65.0	65.0	65.0	65.0	65.0	**585.0**	**472.7**
			Capex	-	-	-	-	-	-	**-**	-	-	-	-	-	**-**	**-**
Timesheet data entry	One of the functions that will be rolled out with the project is the Oracle Time and Labour ('OTL'), which will enable field staff to complete their timesheets directly rather than completing them manually and then sending them to administrative staff to enter into Oracle.	This aspect of the project is expected to result in a saving of [redacted] annum from the fourth year from the project commencement. This functionality will roll out in Year 4 due to other functionality providing higher levels of benefits being rolled out earlier in the project.	Opex	-	-	-	60.0	60.0	60.0	180.0	60.0	60.0	60.0	60.0	60.0	**480.0**	**381.6**
			Capex	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**

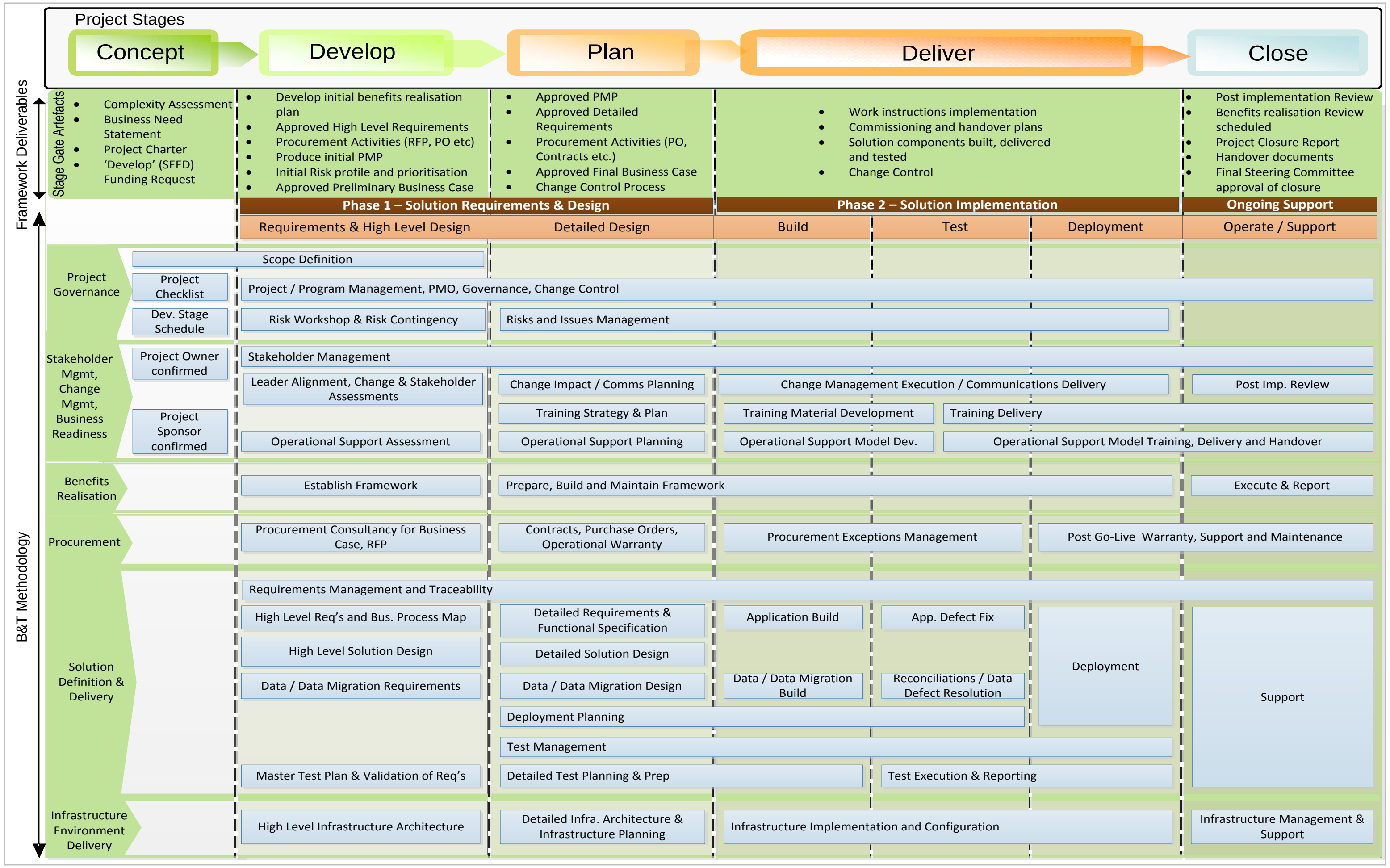
Benefit		Assumptions		Estimate of Benefit by Year ($000, 2016)													
				2017	2018	2019	2020	2021	2022	AA Total	2023	2024	2025	2026	2027	10-year total	PV[23] of 10-year total
Work procedure printing	The project will result in the elimination of the costs associated with distributing technical work procedures to staff and contractors (i.e. printing, document control and distribution costs), because these documents will be made available directly in the field.	The Victorian and Albury networks currently incurs approximately $85k per annum on printing and distributing technical work procedures to the appropriate staff and contractors. These costs are therefore assumed to be eliminated once the project is implemented	Opex	-	-	85.0	85.0	85.0	85.0	**340.0**	85.0	85.0	85.0	85.0	85.0	**765.0**	**618.1**
			Capex	-	-	-	-	-	-	**-**	-	-	-	-	-	**-**	**-**
Reduced depot trips	The current paper-based processes mean field crews must start from a depot each day and need to visit the depot during the week to pick up paperwork or be provided with other required work or employee information. The introduction of the Mobility solution will provide field staff with work in the field, which will enable them to start work from home as well as access to corporate applications, providing important information such as computer based training courses, tool box talk information and Safety Alerts.	To realise these benefits, the mobility functionality needs to be progressively rolled out (i.e. work order management followed by corporate applications) and business processes need to be improved to take advantage of the various additional functionality. The benefits in this area will therefore take longer to realise, which is why they are assumed to be progressively realised until they reach a maximum level in the eighth year from the project commencement. The cost savings in this case have been calculated by assuming that two trips per week can be saved, resulting in 30 mins of time saving per trip, or 52 hours per FTE per year. Based on approximately 120 FTEs, this results in a saving of 6,240 hours per year at [redacted] this mobile functionality is maximised. It is also assumed that these savings are split 50/50 between Capex and Opex as the work volumes are equivalent.	Opex	-	-	-	37.4	37.4	93.6	**168.5**	149.8	187.2	187.2	187.2	187.2	**1,067.0**	**872.1**
			Capex	-	-	-	37.4	37.4	93.6	**168.5**	149.8	187.2	187.2	187.2	187.2	**1,067.0**	**872.1**
Total			**Opex**	-	320.0	521.0	618.4	938.4	1,045.6	**3,443.5**	1,101.8	1,139.2	1,139.2	1,139.2	1,139.2	**9,102.0**	**7,281.2**
Total			**Capex**	-	320.0	371.0	408.4	728.4	835.6	**2,663.5**	891.8	929.2	929.2	929.2	929.2	**7,272.0**	**5,808.8**
Total cost savings				-	640.0	892.0	1,026.9	1,666.9	1,881.2	**6,107.0**	1,993.5	2,068.4	2,068.4	2,068.4	2,068.4	**16,374.1**	**13,090**

Note: Totals may not exactly match the sum of individual costs due to rounding.

Appendix D Methodologies

AGN Project Methodology

To manage all its IT projects, AGN utilises an industry standard Business and Technology (B&T) Project Methodology, which is managed through formal governance. The key aspects of this methodology are outlined in the diagram below.



Business Case – Capex V49

GIS Upgrade

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	Peter Butler, *Manager Network Support Services*
Approved By	John Ferguson, *Group Executive Networks*

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	The current Geospatial Information System (GIS) used in the Victorian and Albury networks (SmallWorld GIS) to manage data associated with Australian Gas Networks Limited's (AGN's) distribution assets is highly customised and becoming increasingly unstable and more difficult and expensive to maintain. The increasing instability of this system, coupled with the difficulty in obtaining support for this system (vendor support for this application ceased in 2010), means there is an increasing risk that the current system may fail (or be unavailable for a period of time), which could have implications for: • public and staff health and safety because the Dial Before You Dig (DBYD) service would be unavailable; • compliance with regulatory obligations under the Retail Market Procedures; • compliance with Energy Safe Victoria's (ESV's) requirement for "an increased emphasis on a risk-based approach to managing and operating assets"; and • asset management decision making. To address these risks AGN is proposing to upgrade the GIS. The upgrade, which is a significant and complex project, will result in a fully supported, secure, integrated enterprise application that will: 1 reduce business risk resulting from an unsupported version of a critical business management application; 2 improve the functionality and upgrade path of the GIS application by removing historical customised functionality; 3 leverage benefits from integrating into an Enterprise IT system architecture; and 4 implement prudent and efficient end to end business processes to ensure ongoing accuracy of GIS data. Ultimately, this project will mitigate a significant business risk associated with an unsupported GIS application and integrate the GIS into the broader Enterprise Asset Management (EAM) suite of IT applications. The proposed upgrade forms part of the National GIS Strategy and Roadmap, the South Australian component of which has recently been approved by the Australian

	Energy Regulator (AER) in its Final Decision on AGN's Access Arrangement (AA) for the 2016/17 to 2021/22 AA period[1]. In approving this project, the AER noted that it was satisfied that "*the proposed capex is conforming capex that complies with rule 79*" 2 of the National Gas Rules (NGR).
Options Considered	The following options have been considered to deal with the risks posed by the existing GIS: 1 Option 1: Do Nothing. 2 Option 2: Upgrade the GIS.
Proposed Solution	Option 2 has been selected because it is the most cost effective way of dealing with the risks posed by the current GIS and is consistent with good industry practice.
Estimated Cost	The total forecast capital expenditure (capex) for this project is $19,558.8 ($000, 2016), of which $ 3,385.1 ($000, 2016) will be spent on Procurement, Development and Planning in the current (2013 to 2017) AA period. The forecast capex for this project in the next (2018 to 2022) AA period is therefore $16,173.7 ($000, 2016).

Consistency with the National Gas Rules (NGR)	The GIS upgrade project complies with the new capex criteria in rule 79 of the NGR because:
	• 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)).
	• it is justified under rule 79(2)(c) because it is required to:
	  • maintain and improve the safety of services (79(2)(c)(i)) - the GIS system is no longer supported by the vendor and therefore has a higher risk of failing for a period of time. If this system fails it will have safety implications for the business, particularly in the availability of Dial Before You Dig (DBYD) information for the public and asset locations for staff and contractors.
	  • maintain the integrity of services (79(2)(c)(ii)) - the non-availability of the GIS application or associated data may have implications on integrity of services through the inability to provide appropriate asset management decisions, such as capacity modelling, asset design and maintenance optimisation,
	  • comply with a regulatory obligation or commitment (79(2)(c)(iii)) – AGN may fail to comply with its regulatory obligations under the Retail Market Procedures and other instruments if the GIS is not available.

Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Safety and Reliability themes as its implementation will allow AGN to maintain the safety of the network whilst continuing to provide a highly reliable supply of natural gas to our customers by reducing the risk associated with an unsupported GIS application. More information detailing the results of AGN's stakeholder engagement program is provided in Chapter 5 of the Access Arrangement Information document.
Supporting Information	• V49 Supporting Information 1 (ESV GPI Safety Management Report Executive Briefing) • V49 Supporting Information 2 (ESV GPI Safety Management Report 2014 – 2015 Non-licensed Gas Infrastructure)

1 AER, *Final Decision: Australian Gas Networks Access Arrangement 2016 to 2021, Attachment 6 – Capital Expenditure*", May 2016, pg. 6-33.
2 AER, "*Draft Decision: Australian Gas Networks Access Arrangement 2016 to 2021, Attachment 6 – Capital Expenditure*", November 2015, pg. 6-42.

1.3. Background

1.3.1. Introduction

Australian Gas Networks Limited (AGN) maintains and operates a number of critical Information Technology (IT) systems that are integral to the efficient and effective management of the Victorian and Albury networks and are required to meet a range of legal and regulatory obligations, including those prescribed in the:

- National Gas Law (NGL) and National Gas Rules (NGR);
- Victorian Gas Distribution System Code[3];
- Victorian *Gas Industry Act 2001*[4]; and
- Victorian Retail Market Procedures[5] (Retail Market Procedures).

These obligations predominantly relate to safely and effectively managing a gas distribution network, ensuring accuracy and timeliness of retail market transactions and delivering against prescribed customer service levels.

They are also required to meet Energy Safe Victoria's (ESV's) gas and pipeline safety requirements[6].

As a prudent operator, AGN has ongoing maintenance plans for its critical IT systems, which are based on the appropriate risk assessments, to ensure continued compliance with these legal, regulatory and safety obligations.

1.3.2. AGN's IT Environment

Given the highly integrated nature of AGN's IT environment, upgrades and improvements to these systems have been incorporated into a detailed *Information Technology Investment Plan*[7] (IT Plan), which has been provided as Attachment 8.5 to AGN's Access Arrangement Information (AAI) document.

This IT Plan details the proposed IT capital program of work over the next AA period, as well as acting to support AGN's business objectives, which, in turn, are aligned with the stakeholder expectations identified during the stakeholder engagement program recently undertaken by AGN in Victoria and Albury[8].

In the current AA period, a number of major projects to nationalise and upgrade key IT application systems were implemented. These projects delivered improved IT systems with increased scalability, flexibility and reliability, while also ensuring that AGN continues to meet its obligations under the RMP and other relevant regulatory and customer obligations. The IT systems nationalisation program has so far successfully delivered to Victoria and Albury the Enterprise Asset Management (EAM) system, the National Metering and Billing (MnB) system and other core foundation platforms to leverage efficiencies in business operations through data consolidation, enablement of standard national processes and task automation.

3 Essential Services Commission, "*Gas Distribution System Code*", Version 11.0.
4 http://www.austlii.edu.au/au/legis/vic/consol_act/gia2001167/
5 AEMO, http://www.aemo.com.au/Gas/Policies-and-Procedures/Retail-Gas-Market-Procedures/Victoria
6 http://www.esv.vic.gov.au/About-ESV
7 APA, "*Victorian and Albury Networks Information Technology Investment Plan for the 2018 to 2022 Access Arrangement Period*", July 2016
8 Deloitte, "*Australian Gas Networks Customer Insights Report, Victorian and Albury Stakeholder Engagement Program*", May 2016.

Additional projects to complete the nationalisation program during the next (2018 to 2022) AA period have been included in separate business cases. The completion of the nationalisation program of work is required in order for AGN to realise the full business benefits from moving towards the national enterprise structure and the integrated suite of systems, including enhanced EAM capability, streamlined and scaled applications and processes, and improved risk mitigation. The ultimate beneficiaries of these improvements will be AGN's customers.

This business case describes the requirements and provides business justification for the GIS Upgrade project. The proposed upgrade forms part of the National GIS Strategy and Roadmap, the South Australian component of which has recently been approved by the AER in its Final Decision on AGN's AA for the 2016/17 to 2020/21 AA period. In approving this project, the AER noted that it was satisfied that "*the proposed capex is conforming capex that complies with rule 79*" of the NGR.

1.3.3. Issues and risks associated with the existing GIS

The current SmallWorld GIS application in Victoria plays a critical role in the management of network assets and locations. It contains a database of records for mains, regulators and valves as well as property addresses that are used in the Enterprise Asset Management (Maximo) and Metering and Billing (CC&B) systems. SmallWorld also provides key network configuration and location information for network capacity modelling and responses to external requests for the location of mains assets through Dial Before You Dig (DBYD).

The SmallWorld (Version 3.3) GIS application was installed in 2004 and over the last 12 years has been heavily customised to deliver the required business functionality. As a result, it is difficult to upgrade and support due to the amount of custom code used. Due to this customisation and associated upgrade costs, software patches to improve product functionality have not been implemented and various manual workarounds have been necessary to overcome core product functional issues. This has now resulted in the current version of the SmallWorld application becoming unsupported by the application vendor.

This exposes AGN to a number of significant business risks, including

- Health and safety risks, because this application is integral to critical network functions such as DBYD information, capacity modelling data and compliance with ESV requirements to demonstrate a risk-based approach to managing and operating assets (see Box 1.1); and
- Compliance risks, because the availability of this application is required to comply with AGN's obligations under a number of legislative and regulatory instruments, including the Retail Market Procedures (see Box 1.2). For example, there is a risk that MIRN data stored in the GIS cannot be provided to the market if the application fails.

These risks are becoming more prominent as the application ages and becomes less stable, which is evident from the increasing number of incidents and outages. For example, from January 2015 to April 2016, SmallWorld GIS had over 140 incidents of inaccessibility of applications/maps or poor performance requiring systems reboot or applications re-start.

Additionally, interfaces between new systems (e.g. DBYD) and SmallWorld GIS are custom built and cannot be standardised due to SmallWorld's age, adding further risk around support of these interfaces. Support for these interfaces cannot be formalised and there is a risk of not being able to upgrade them in future.

As a result of these issues and risks, the total cost to maintain the existing GIS application is increasing as technical resources with experience in the unsupported version are becoming more difficult to source and relatively minor upgrades and fixes are becoming more complex due to the level of customisation.

An upgrade or change-out of the SmallWorld application is required to mitigate the business risks outlined above and stabilise the total cost of GIS ownership. This can be achieved by moving to a fully supported GIS application that has enhanced base functionality and application security requiring minimal or no customisation and enables future releases to follow the standard application upgrade path.

Box 0.1: ESV's expectations for a risk-based approach to asset management

In the 2014/15 Gas & Pipeline Infrastructure (GPI) Safety Management Report[9], the ESV noted that it expects Victorian distributors to start employing more of a risk based approach to asset management and that it expects to see:

> *"more evidence that risk-based approaches are being adopted, implemented and sufficiently resourced, and that risk-mitigation requirements are being driven by effective analysis."*[10]

In doing so, the ESV made the following observations:

> *"Pipeline risk is dynamic, increasing as assets age and corrode and as the types of activities in and around pipelines and their easements change."*[11]

> *"Empirical evidence also suggests that most high-impact, low-probability incidents occur because of the aligned failures or partial failures of a number of physical and procedural barriers (threat barriers) designed to prevent injury or damage to people, property and the environment, rather than because of an isolated major failure."*[12]

> *"In 2013/14, incidents damaging mains and services peaked and there has been no level of improvement to these statistics that demonstrates asset owners are understanding and identifying the root cause of these incidents and sufficiently mitigating the risk to infrastructure and potential harm to people."*[13]

> *"Third-party interference and structural failures have the potential to cause high consequence events involving death and significant supply interruption…… the number of hits on mains and services (causing damage and gas escape) remains excessively high."*[14]

> *"Proposed land development and third-party works around pipelines need to not only be accurately captured but also competently assessed…"*[15]

> *"…safety framework documentation complying with pre-existing standards is no longer acceptable….. an increased emphasis on a risk-based approach to managing and operating assets is now required."*[16]

In order to meet the ESV's increased expectations around the risk-based approach to asset management and operation, accurate data and appropriate data analysis tools are required to optimise effective asset monitoring, analysis and risk management.

[9] *Energy Safe Victoria, "GPI Safety Management Report 2014/15 – Executive Briefing", June 2016*
[10] *Energy Safe Victoria, "GPI Safety Management Report 2014/15 – Executive Briefing", June 2016, pg.5.*
[11] *Energy Safe Victoria, "GPI Safety Management Report 2014/15 – Executive Briefing", June 2016, pg.4*
[12] *Energy Safe Victoria, "GPI Safety Management Report 2014/15 – Executive Briefing", June 2016, pg. 4.*
[13] *Energy Safe Victoria, "GPI Safety Management Report 2014/15 – Executive Briefing", June 2016, pg. 5.*
[14] *Energy Safe Victoria, "GPI Safety Management Report 2014/15 – Executive Briefing", June 2016, pg. 5.*
[15] *Energy Safe Victoria, "GPI Safety Management Report 2014/15 – Executive Briefing", June 2016, pg. 5.*
[16] *Energy Safe Victoria, "GPI Safety Management Report 2014/15 – Executive Briefing", June 2016, pg. 8.*

Box 0.2: AGN's Obligations under Retail Market Procedures

In accordance with Section 1.2 of the Victorian Retail Market Procedures (RMP), the Australian Market Operator (AEMO) established a Gas Interface Protocol (GIP), which governs the manner and form in which information is to be provided, notice given, notices or documents delivered and requests made as contemplated by the RMP. Further, Section 1.2.4 of the RMP states that AGN is *"bound by, the Gas Interface Protocol in respect of the provision of information, giving of notice, delivery of notices or documents and making of requests, and the receipt of information, notice, notices, documents or requests, as contemplated by these Procedures."* and *"any failure to use the FRC HUB in accordance with the FRC HUB Operational Terms and Conditions may result in AGN being issued a breach notice."*

If the breach is found by AEMO to be material, it must be referred to the AER under section 91B of the National Gas Law (NGL). This provision in the NGL is a civil penalty provision, which means that the AER can issue an infringement notice[17] and/or institute civil proceedings in the Federal Court and seek an injunction or an order that AGN remedy the breach; and/or an order that a penalty be paid.[18] In addition, Participant Build Pack 3 - FRC B2B System Architecture Section 6, specifically addresses security noting *"An Internet based message service, by its very nature, presents certain security risks… Beyond the requirements herein, participants should make themselves familiar with these risks and institute countermeasures balanced against an assessment of the inherent risks and the value of the asset(s) that might be placed at risk."*

As a prudent operator, AGN has undertaken appropriate risk assessments of the criticality of its IT systems and infrastructure and considers the periodic refresh of critical IT infrastructure in accordance to industry good practice to be the most efficient and effective means of ensuring continued compliance with the wholesale market requirements.

1.4. Risk Assessment

The overall untreated risk associated with the current GIS has been assessed as 'Extreme' due to the potential for multiple deaths from striking AGN gas assets. As the GIS application becomes more and more obsolete, the likelihood of a catastrophic failure increases, with consequences in the following areas:

- *Health and Safety* - DBYD asset location maps may no longer be available to the public, significantly increasing the likelihood of damage to AGN assets and endangering the public safety. Also, AGN contractors (predominantly APA) will not have access to asset location information in the field, resulting in a greater likelihood of damaging those assets and increasing the chance of outages, gas leaks and potential explosions. The Health and Safety consequence rating becomes 'Catastrophic' due to the lack of AGN asset information for Third Parties and subsequent increased likelihood of injury and the potential for multiple deaths from striking AGN assets.
- *Operational* - Lack of a current and reliable GIS will result in an inability to make spatial and logical queries, significantly longer network modelling and inefficient responses to customer reported faults. In addition, security breaches may result in confidential customer data being compromised.
- *Customers* - Customers may be impacted significantly if they lose supply due to inadvertent strikes on AGN assets, either by a third party or AGN contractors, or they or their assets are impacted by an explosion / leak.

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[17] *The maximum infringement notice is $4,000 for individuals ($20,000 for body corporates).*

[18] The maximum civil penalty is $20,000 for individuals ($100,000 for body corporates), plus $2,000 ($10,000) for every day it continues.

- *Reputation* - AGN's reputation could be damaged significantly in the event of health and safety incidents; supply disruptions; delayed repairs and maintenance; environmental damage, compromised corporate and customer information and resultant litigation.
- *Compliance* –The loss of DBYD functionality would fail to comply with ESV's safety expectations for the public as well as availability of asset maps for internal employees and contractors. AGN's ability to comply with the Retail Market Procedures would also be compromised, for example in the provision of MIRN detail to the market.
- *Financial* - The lack of DBYD asset information increases the likelihood of third party damage to AGN assets and corresponding costs to repair those assets. While difficult to quantify, the availability of DBYD information provides a cost avoidance benefit where those damages are avoided. The health and safety, operational, customer and reputation consequences outlined above may also result in significant additional costs (for example, through compensation payments).

A summary of the untreated risks is presented in Table 1.3. Further detail on the risk assessment can be found in Appendix A to this business case.

Table 1.3: Risk Rating

Risk Area	Untreated Risk Level
Health and Safety	Extreme
Environment	Negligible
Operational	Moderate
Customers	High
Reputation	Low
Compliance	High
Financial	High
Untreated Risk Rating	**Extreme**

1.5. Options Considered

AGN has considered the following options to address the risks outlined in Section 1.4:

- Option 1: Do nothing and continue to operate under the current GIS; or
- Option 2: Upgrade the GIS.

1.5.1. Option 1 – Do Nothing

This option involves using the existing unsupported and heavily customised version of the GIS application.

1.5.1.1. Cost/Benefit Analysis

Apart from the deferral of expenditure, there are no benefits associated with the Do Nothing option. Retaining the legacy SmallWorld GIS will lead to increased safety, integrity of service and compliance risks and higher operational costs relative to the current AA period. The increased costs include ongoing software support (requiring specialist GIS skillset), costs associated with rectifying business interruptions and business costs associated with assets being damaged due to map data not being available for DBYD inquiries. Additionally, if the risks associated with potential incidents results in injury or death or damage to property, this may result in significant additional costs (for example, through compensation payments or financial penalties).

The other important point to note about this option is that it will do nothing to reduce the risks associated with the current GIS as outlined in Section 1.4, which is why it is not considered a viable option.

1.5.2. Option 2 – GIS Upgrade

The second option AGN has identified will involve:

- replacing the SmallWorld GIS;
- a full re-implementation of the GIS application;
- cleansing and conversion of large volumes of data;
- system integration to related Enterprise systems; and
- business-wide change management effort associated with changing business processes for over 500 staff and contractors.

1.5.2.1. Cost/Benefit Analysis

The total capital cost of Option 2 is estimated to be $19,558.8 ($000, 2016). This amount includes the $3,385.1 ($000, 2016) cost of the planning phases of the project that will be undertaken at the national enterprise level in 2017, prior to commencement of the next AA period. The total capital cost of Option 2 in the next AA period is, therefore, $16,173.7 ($000, 2016).

In terms of benefits, the overarching objective of this project is to mitigate the risk of having a critical system that is not supported and is at risk of being unable to be recovered should the system fail. This risk is escalating year on year because the current SmallWorld (Version 3.3) was installed in 2004 and is no longer supported. It is also becoming more problematic to source IT resources that have the knowledge and skillset to maintain the system as the programming code used in the existing version is no longer used in other applications, as highlighted by Table 1.4, which sets out the costs of the Do Nothing option.

The other key benefit of the full implementation of an Enterprise GIS without customisations is to contain the cost of future upgrades. Currently, the GIS has significant customisations and a data model that does not align to a recent GIS version. As per the V46 Application Renewals Business Case, if this full re-implementation is not completed future upgrades will increase in cost due to ongoing data and functionality issues.

On completion of this project, the Victorian GIS application will be a fully supported, integrated enterprise application that will provide a cost effective solution to mitigate the key business risks associated with the current highly customised system, which as noted above is becoming more difficult and expensive to maintain. The upgrade will also enable:

- standardised national processes to be implemented to simplify work practices and maintain integrity of data;
- support costs to be contained because the vendor will support the current 'vanilla' version of software;
- improvement of security and data integrity levels;
- the GIS to be integrated with the other key systems through the use of a Service Orientated Architecture, which will provide foundation IT architecture in such areas as mobility, geospatial location of work through EAM, and Business Intelligence applications to enable optimised asset decision-making; and
- future upgrade costs to be contained as the application follows the standard upgrade path; and
- compliance with the Victorian Retail Market Procedures to ensure accurate data is provided to the market

As can be seen from the detailed risk assessment in Appendix A, if this option is implemented the overall risk rating will be reduced from Extreme to Moderate.

1.6. Summary of Cost/Benefit Analysis

A summary of costs, benefits and risks of the options considered in this business case is provided below.

Table 1.5: Summary of Cost/Benefit Analysis

Option	Benefits	Costs/Risks
Option 1 – Do Nothing	Defers Expenditure	Retaining the SmallWorld GIS will lead to increased operational costs relative to the current AA period, due to: • increased software support costs because technical resources with experience in the unsupported version of the GIS are becoming more difficult and costly to source; • increased costs associated with rectifying more frequent business interruptions; and • increased business costs associated with assets being damaged due to map data not being available for DBYD inquiries. As outlined in Section 1.4 and Appendix A, there is an 'Extreme' level of risk associated with system failures and outages from running an unsupported and heavily customised version of the GIS application because if the GIS fails (or is unavailable for a period of time), it will have implications for: • public and staff health and safety, including the potential for multiple deaths from striking AGN gas assets, because the DBYD service would be unavailable; • potential for third party asset damage due to unavailability of asset locations; • compliance with regulatory obligations under the

		Retail Market Procedures; • compliance with ESV requirements; and • asset management decision making. These consequences may also result in significant additional costs (for example, through compensation payments or financial penalties for non-compliance).
Option 2 – GIS Upgrade	The benefits of this option are that it will: • reduce the residual risks to human health and safety associated with the current GIS from extreme to moderate (see Appendix A) and the other customer, compliance and financial risks outlined in Section 1.4 to moderate; • contain costs of future upgrades; • implementation of standardised national processes to simplify work practices and maintain integrity of data. • leverages benefits from integrating with other key enterprise systems, including optimised asset decision-making through the use of mobility, EAM and business intelligence applications. • facilitates compliance with regulatory obligations under the Retail Market Procedures and ESV requirements. As outlined in Appendix A, upgrading GIS will reduce the overall level of risk from 'Extreme' to 'Moderate'.	$16,173.7 ($000, 2016) over the next AA period.

1.7. Proposed Solution

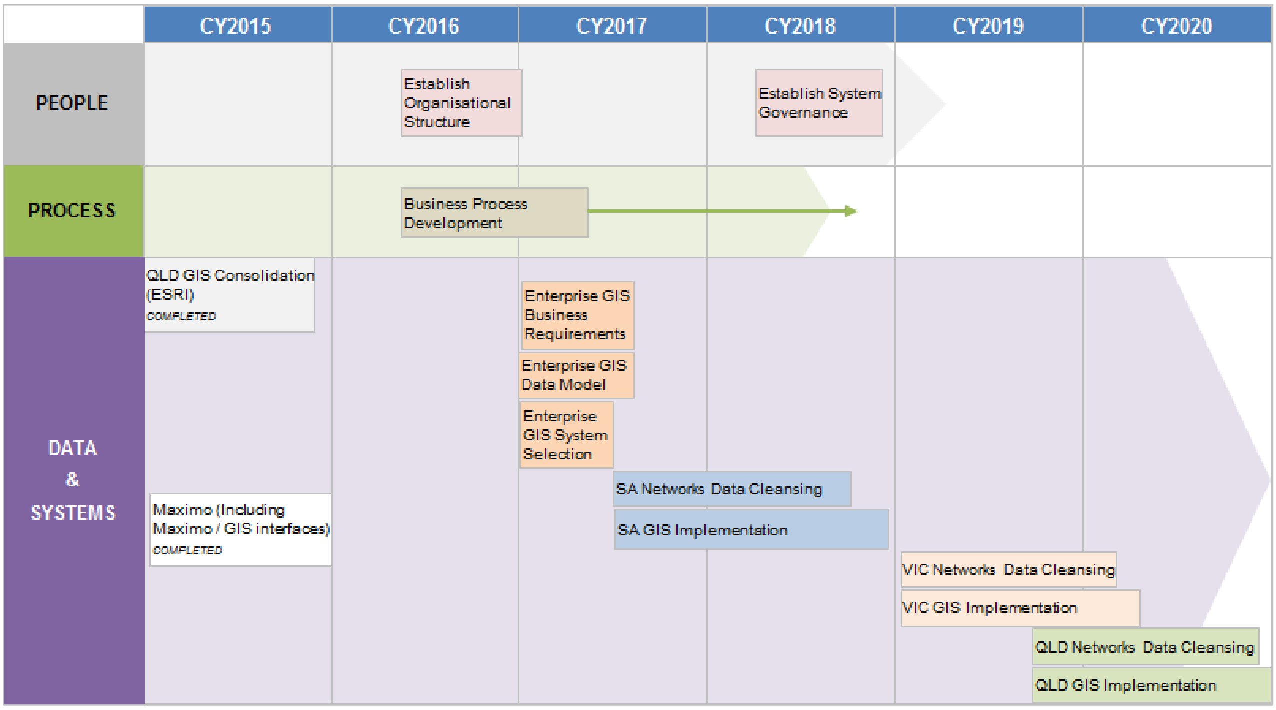
1.7.1. What is the Proposed Solution?

The proposed solution is Option 2, which will involve replacing the existing obsolete SmallWorld GIS application with a significantly upgraded version and implementing an Enterprise GIS application to manage data associated with AGN's distribution assets.

Due to the highly integrated nature and broad use of various GIS applications across the business, AGN has developed a National GIS Strategy Roadmap, guided by the AGN Geospatial Strategy[19], to provide a structured approach to the upgrade. This roadmap is set out in Figure 2. As the roadmap highlights, the planning for the Enterprise GIS project has commenced in the current AA period. The implementation for the Victorian GIS Upgrade project will follow the South Australian (SA) GIS Upgrade implementation, which has been recently approved by the AER in its Final Decision and is scheduled to commence in 2017.

[19] Strada and Associates, "*Geospatial Strategy*", December 2013

Figure 1: National GIS Strategy Roadmap



The GIS Upgrade project will fully implement a GIS application that will utilise the Enterprise platform. This Enterprise approach is considered optimal to leverage the available economies of scale across the business and aligns with the integrated structure of the network's IT systems. As detailed in the Enterprise GIS roadmap, the GIS Upgrade project is scheduled to commence in January 2017 in South Australia, followed by Victoria and Albury, then Queensland/NSW (Wagga Wagga).

Due to the age of the existing system, the project will encompass a full implementation of a Tier 1 GIS application to provide the required base 'vanilla' functionality and will be supported by a detailed system evaluation process. This system evaluation process will include a system selection procurement exercise to ensure the GIS system selected fully addresses the business GIS requirements.

The project elements based on the Enterprise-wide and state-specific requirements for the implementation are as follows:

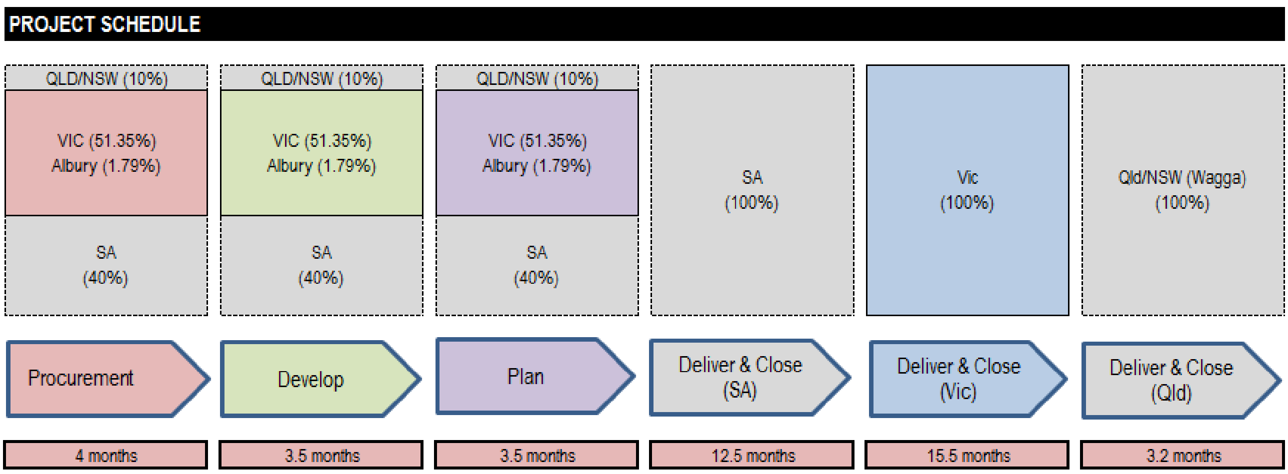
- Enterprise-wide:
  - system selection procurement process;
  - application design and implementation (with minimal or no customisation);
  - development of a new Enterprise GIS data model;
  - sourcing of appropriate hardware or data centre requirements; and
  - software licences.
- State-specific (Victoria and Albury only):
  - cleansing of existing data, including cadastre update;
  - data migration from the existing GIS into the new data model;

- system integration into related applications (Maximo, CC&B, capacity modelling applications, mobility applications, DBYD);
- streamlining business processes required to maintain data integrity; and
- system training.

As the system will be implemented across all jurisdictions that AGN operates in, some elements of the project, such as system and data model design, will benefit from the economies of scale associated with leveraging the effort over multiple states (South Australia, Victoria and Albury, Queensland/NSW). Each state will also have a state-specific implementation with all costs attributable to that State. In terms of the phases of the project, the Procurement/Develop and Plan phases will be delivered on an Enterprise basis, with each state then having state-specific Deliver and Close phases.

The proposed project schedule is shown in Error! Reference source not found. below.

Figure 2: GIS Upgrade Project Schedule



This schedule is based on an enterprise implementation of the GIS and as such, the Procurement, Develop and Plan phases of the project are conducted at an Enterprise level. The costs of these phases are apportioned based on AGN's customer numbers (and, by implication, associated asset data) between each state, with Victoria and Albury accounting for 51.35% and 1.79% respectively, of customers as at 31 December 2015.

At the Deliver phase, the project then rolls out in consecutive states because running these concurrently presents significant project risk. This roll out process has been used with success in other enterprise projects, including most recently on the EAM and Metering & Billing projects. For the GIS Upgrade, South Australia will be the first state to be rolled out, followed by Victoria and then Queensland/NSW. The Deliver phase costs for each rollout are fully attributable to the State being rolled out.

1.7.2. Why are we proposing this Solution?

This project is being proposed because it will reduce the health and safety, operational and compliance related risks that are associated with the existing unsupported GIS application from 'Extreme' to 'Moderate' (see Appendix A). The project will also:

1. improve the functionality and upgrade path of the GIS application by removing historical customised functionality;
2. improve the levels of security and data integrity;
3. leverage benefits from integrating into an Enterprise IT system architecture; and
4. implement prudent and efficient end-to-end business processes to ensure ongoing accuracy of GIS data.

On completion of this project, the Victorian and Albury GIS application will be a fully supported, secure, integrated enterprise application that will provide a cost effective solution to mitigate the key business risks associated with the current unsupported and highly customised system, which is becoming more difficult and expensive to maintain.

1.7.3. Forecast Cost Breakdown

1.7.3.1. Costing methodology

The proposed GIS Upgrade is a national project, so the total project cost has been estimated based on the work that is needed to be carried out across all Australian jurisdictions that AGN operates in. The total project cost is then allocated to state-specific AGN networks based on the customer numbers across each of the networks, to ensure that the cost allocations used reflect how AGN ultimately allocates costs to customers served from these networks. As at 31 December 2015, Victoria and Albury accounted for 51.35% and 1.79% of AGN's total customer numbers, respectively.

It is worth noting that the same approach has been used to estimate the costs of the South Australian component of the GIS Upgrade project, which was approved by the AER in its Final Decision. In approving this project, the AER noted that it was satisfied that[20] "*the proposed capex is conforming capex that complies with rule 79*" of the NGR.

The approach that AGN has used to estimate the total project costs for the GIS Upgrade project and the proposed approach to carrying out the work is outlined below:

- AGN utilises an industry standard Business & Technology (B&T) Project Methodology, which is managed through formal governance. This B&T Methodology divides the projects into key stages – concept, develop, plan, deliver and close. Each stage consists of key tasks and activities to ensure the consistency and standardisation across projects. The project methodology is outlined in Appendix C.
- To ensure project cost estimates are developed in a consistent manner, AGN utilises an Estimation Tool, which is aligned with the B&T Project Methodology. This estimation tool has been used to forecast the work and cost estimates across a variety of AGN IT projects. This estimation tool utilises historic figures for similar projects for resource work effort estimates. All historic figures are sanity checked to ensure any changes to the way historical projects were carried out were taken into account. The work effort estimates are based on a complexity matrix tool, which uses a series of questions to categorise projects into simple, medium and complex.
- The material and direct labour costs, and applicable planning, design and commissioning charges, are based on historic actual costs of similar projects and on vendor quotes subject to a competitive tendering process in accordance with the APA Procurement policy and

20 AER, "*Draft Decision: Australian Gas Networks Access Arrangement 2016 to 2021, Attachment 6 – Capital Expenditure*", November 2015, pg. 6-42.

guidelines[21]. Resource Unit Costs (both internal and external) are based on AGN's Project Management Office (PMO) research, where actual placement costs have been used based on historical project resources and current resourcing rates (2016).

- The historic figures and work effort estimates are used as inputs into the final estimates, which are subject to stringent review and endorsement by members of the IT Estimates Review Committee. The work effort, cost and timing of projects are monitored throughout the project lifecycle to ensure on time and on budget delivery.
- When implementing the project, AGN will use a formalised Project Methodology and utilise a combination of internal and external resources (through vendors and trusted recruitment agencies) to deliver the program of work to ensure that services are carried out in a prudent and efficient manner. The Project Methodology is outlined in Appendix C and provides a consistent, standard and quality assured project implementation framework. The PMO will provide guidance and governance to the project, ensuring that the work is carried out in a prudent and efficient manner.

A key principle that has been employed when developing these internal and external resource estimates is that enterprise economies of scale are achieved through utilising standardised business processes, data models, data migration techniques and existing hardware platforms should be reflected in the estimate. For example, a reduced amount of testing was factored into the estimates because under the Nationalisation approach, testing of the new GIS will be performed concurrently across all jurisdictions. This approach results in a lower Victorian project cost than would have occurred in the event of a stand- alone Victorian and Albury project.

The internal resource rates have been market tested to ensure the rates are not higher than the average rates across the industry for comparable skills and experience levels. Where additional specialist internal resources need to be brought to the project, the internal resource rates are based on market rates for specialist resources required for a GIS application. There is a smaller pool of GIS expertise available in the market and the resource rates reflect the specialist nature of those resources. AGN uses specialist resources in IT to support the current GIS and as a result, has relevant recent experience in the limited availability and specialist nature of these resources.

The Professional Services and Software costs have been estimated by We-Do-IT, a key IT partner with a detailed understanding of the SmallWorld GIS through maintaining that GIS over many years. The project duration has also been built from 'bottom-up' in the cost model and ratified through the We-Do-IT estimate. These resource estimates and project duration have also been tested against previous projects such as Enterprise Asset Management, Metering and Billing and Qld GIS Consolidation as well as being subject to internal IT Estimates Committee review.

1.7.3.2. Resource estimates

The GIS Upgrade project requires a mix of external and internal IT resources.

The internal resource costs have been estimated from the bottom up by breaking the project into stages and tasks and considering the requirements (skill set and time) for each task. Where additional specialist internal resources need to be brought to the project, the hourly rates have been differentiated by resource types and are based on the current market rates for these roles. The internal labour costs include the following:

- internal project management;
- change management;
- business process re-design;

[21] Available upon request.

- system integration;
- business analyst and Subject Matter Expert (SME) support; and
- training.

External vendor costs have also been considered and include the following:

- external project management;
- application design;
- system build; and
- system implementation and testing.

A significant exercise required for the GIS Upgrade is the cleansing of existing data, including implementing a new cadastre. The cost model estimate for data cleansing includes:

- realignment to a new cadastre;
- implementation of connectivity between specific assets;
- removal of duplicate and redundant data; and
- upgrading to an Enterprise data model.

1.7.3.3. Total forecast cost

The application of this methodology resulted in a total capital cost estimate of $19,558.8 ($000, 2016). This includes $3,385.1 ($000, 2016) in capex that will be spent on the planning phases of the project that will be undertaken at the national enterprise level in 2017, prior to commencement of the next AA period. The estimated capex for the next AA period is therefore $16,173.7 ($000, 2016).

1.7.3.4. Costs over the next AA period

The total cost breakdown by project phase is provided in Appendix B and the detailed cost breakdown over the next AA period is given in Section 1.7.3.

The breakdown of the forecast project cost over the next AA period is provided below. As discussed earlier, the planning phases of the project (namely, the Procurement, Develop and Plan phases depicted in **Error! Reference source not found.**) will be undertaken in the current AA period. The project costs for the next AA period, therefore, only include the costs of the Deliver and Close phases of the project and do not include in the cost of the planning phases. The full breakdown of the project capital costs by phase is provided in Appendix B.

Table 1.6: Capex/Opex Split ($000, 2016)

	2018	2019	2020	2021	2022	Total
Capex	-	11,069.7	4,899.0	205.0	-	16,173.7
Opex	-	-	-	-	-	-
Total	**-**	**11,069.7**	**4,899.0**	**205.0**	**-**	**16,173.7**

Note: Totals may not exactly match the sum of individual costs due to rounding.

Table 1.7: Project Cost Estimate, Capex, by cost category ($000, 2016)

	2018	2019	2020	2021	2022	Total
Direct Labour	-	6,581.9	2,975.6	-	-	9,557.5
Materials	-	2,914.8	1,249.2	-	-	4,164.0
Contracted Labour	-	1,453.5	622.9	205.0	-	2,281.4
Facilities	-	119.5	51.2	-	-	170.8
Total	**-**	**11,069.7**	**4,899.0**	**205.0**	**-**	**16,173.7**

Note: Totals may not exactly match the sum of individual costs due to rounding.

Table 1.8: Capex Split Between Victoria and Albury ($000, 2016)

	2018	2019	2020	2021	2022	Total
Capex - Victoria	-	10,696.8	4,734.0	198.1	-	15,628.9
Capex - Albury	-	372.9	165.0	6.9	-	544.8
Total	**-**	**11,069.7**	**4,899.0**	**205.0**	**-**	**16,173.7**

Note: Totals may not exactly match the sum of individual costs due to rounding.

It is worth noting that since the original project costing was developed in real 2014/15 values, an escalation was required to express the costs in real 2016 values. The adopted escalation factor of 1.025 has been derived from the Australian Bureau of Statistics (ABS) Consumer Price Index report (All groups, Australia). This escalation has been applied to all costs in this business case.

It is also worth noting that the amount of $205.0 ($000, 2016) in 2021 represents the cost of system maintenance in the first year after implementation that is capitalised under AGN policy.

1.7.4. Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN considers that the capex required to implement the GIS Upgrade Project is:

- *Prudent* – The expenditure is necessary in order to maintain and improve the safety of services, maintain the integrity and security of services and comply with regulatory obligations and requirements and is of a nature that a prudent service provider would incur.
- *Efficient* – The GIS Upgrade will enable AGN to improve operational efficiency and address the high risks of non-compliance with the Retail Market Procedures and other relevant safety, regulatory and legislative obligations. It will also reduce the risks of customer and business interruptions and corresponding adverse financial and reputation impacts. The manner in which AGN proposes to carry out this project and the governance processes it has in place (see the IT Investment Plan), will also ensure that costs are efficiently incurred. The expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.

- *Consistent with accepted good industry practice* – The GIS Upgrade project will enable AGN to operate in line with good industry practice, in terms of having all critical systems up to date and supported by vendors with minimal customisation and baseline functionality. It is worth noting that many of the AGN's gas and electricity distribution counterparts understand the criticality of their asset data and are continually investing into the associated GIS capabilities required to appropriately manage that data. This is evident from the recent regulatory proposals and the capex spend approved by the AER for SA Power Networks and Jemena, among others.[22]
- *Achieves the lowest sustainable cost of delivering pipeline services* – The GIS Upgrade Project is required to maintain an IT system that is critical to the delivery of safe and efficient pipeline services and over the medium to longer term will contribute to the achievement of the lowest sustainable cost of service delivery.

The capex can therefore be viewed as being consistent with rule 79(1)(a) of the NGR.

The proposed capex is also consistent with rule 79(2)(c), because the expenditure is necessary to:

- *Maintain and improve the safety of services (rule 79(2)(c)(i))* - The GIS system is no longer supported and therefore has a higher risk of failing for a period of time. If the system is not available it will have safety implications for the business, particularly in the availability of DBYD information for the public and asset locations for staff and contractors.
- *Maintain the integrity of services (rule 79(2)(c)(ii))* - If the GIS application or associated data is not available it will have implications for the integrity of services through the inability to provide appropriate asset management decisions, such as capacity modelling, asset design and maintenance optimisation.
- *Comply with a regulatory obligation or commitment (rule 79(2)(c)(iii))* – If the GIS is not available it could result in regulatory obligations under the Retail Market Procedures being breached and AGN being unable to improve its risk-based approach to asset management as required by the ESV.

[22] See, for example, SA Power Networks Regulatory Proposal 2015-2020, Attachment 20.40, *SA Power Networks: IT Enterprise Asset Management Business Case*, July 2015 p.69 and Jemena Electricity Networks (Vic) Ltd 2016-20 Electricity Distribution Price Review Regulatory Proposal, Attachment 7-7, *IT Asset Management Plan (2016-2020),* 30 April 2015.

Appendix A Risk Assessment

The risk assessments below demonstrate the change in risk profile associated with both options. As noted above, in the event the GIS Upgrade is not undertaken, the risk associated with the unavailability of the GIS will rise to Extreme during the next AA period.

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Option Risk
Risk Untreated Option 1 – Do Nothing	**Likelihood**	*Occasional*	*Rare*	*Occasional*	*Likely*	*Occasional*	*Likely*	*Likely*	**EXTREME**
	Consequence	*Catastrophic*	*Minor*	*Medium*	*Medium*	*Minor*	*Significant*	*Significant*	
	Risk Level	*Extreme*	*Negligible*	*Moderate*	*High*	*Low*	*High*	*High*	
Residual Risk Option 2 – GIS Upgrade	**Likelihood**	*Rare*	*Rare*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	**MODERATE**
	Consequence	*Major*	*Minor*	*Medium*	*Medium*	*Minor*	*Significant*	*Significant*	
	Risk Level	*Moderate*	*Negligible*	*Moderate*	*Moderate*	*Low*	*Moderate*	*Moderate*	

In the event Option 1 – Do Nothing is adopted, the likelihood of the GIS failing and being unable to be recovered over the next Access Arrangement period increases significantly as the platform becomes more unstable and appropriately skilled resources to maintain the unsupported system become more difficult to source.

The most serious consequences would be explosions and multiple deaths from AGN assets being struck, either by the public or staff and contractors working on AGN assets.

Appendix B Detailed Cost Estimate

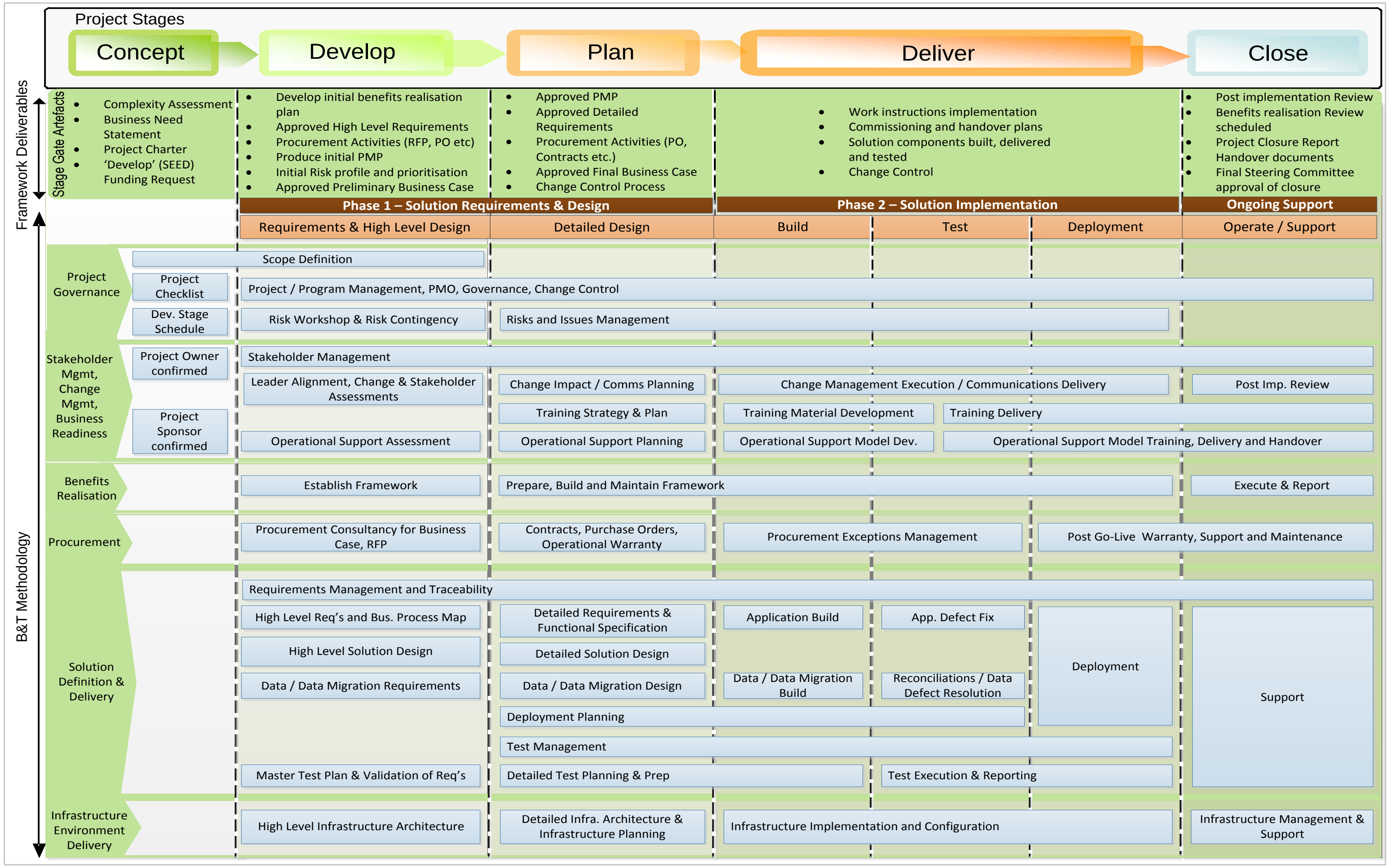
The table below sets out the total project cost estimate by project phase and includes internal and external resources and the data cleansing costs. Detailed estimates are available for each project phase, including project resources breakdown, professional services costs, hardware costs, and software licence and maintenance costs.

Table B.1: Business GIS Upgrade Capex By Stage

IT & ICT Procurement Estimations Template: B&T Projects		
Project Name:	GIS Upgrade	
Project Complexity:	Complex	
Project Type:	Major Change	
Estimations Summary		
	Effort (Days)	Total Cost
End to End Total	8,755	19,558,796
Estimations by Project Stage		
Develop Stage Total	1,039	1,750,483
Plan Stage Total	818	2,378,524
Deliver Stage Total	6,755	15,234,625
Close Stage Total	144	195,163

Appendix C AGN Project Methodology

To manage all its IT projects, AGN utilises an industry standard Business and Technology (B&T) Project Methodology, which is managed through formal governance. The key aspects of this methodology are outlined in the diagram below.



Business Case – Capex V50

Infrastructure Renewal

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	Paul Murphy, *Infrastructure and Support Manager*
Approved By	Bill Fazl, *General Manager Information Technology*

1.2. Project Overview

Table 1.2: Business Case Project Overview

Description of Issue/Project	The Infrastructure Renewal project involves the upgrade of Australian Gas Networks Limited's (AGN's) desktop and telephony infrastructure in Victoria and Albury over the next (2018 to 2022) Access Arrangement (AA) period. The existing infrastructure is nearing the end of its useful life and the upgrade is required to ensure that AGN continues to provide reliable, secure, compliant and efficient business processes and systems and maintain the integrity of its services. If the project is not carried out, AGN's critical business systems may be exposed to higher security risks and a greater risk of failure or prolonged outage. This would adversely affect the safety and integrity of services and could result in AGN failing to fulfil its customer and regulatory obligations under the Victorian Retail Market Procedures and other legislative and regulatory instruments. The work proposed in this business case forms part of the National Infrastructure Renewal program across all jurisdictions AGN operates in. The South Australian component of this project[1] has been recently approved by the Australian Energy Regulator (AER) in its Final Decision on AGN's AA for the 2016/17 to 2020/21 AA period[2]. In approving this project, the AER noted that it was "conforming capex that complies with rule 79 of the NGR"[3].
Options Considered	The following options have been considered for the Victorian and Albury networks over the next AA period to deal with the risks posed by the existing infrastructure: 1 Option 1: Do Nothing; or 2 Option 2: Upgrade the desktop and telephony infrastructure in the next AA period.
Proposed Solution	Option 2 has been selected because it is the most cost effective way of dealing with the risks posed by outdated and unsupported infrastructure and is consistent with good industry practice.

1 AGN," *Access Arrangement 2016-21 proposal"*, Attachment 7.1_Business Cases.pdf, Business case SA82 - South Australian Infrastructure Renewal project for the FY2016/17 to FY2020/21 AA period, July 2015.

2 AER, "*Final Decision: Australian Gas Networks Access Arrangement 2016 to 2021*, Attachment 6 – Capital Expenditure", May 2016, p. 6-33.

3 AER, "*Draft Decision: Australian Gas Networks Access Arrangement 2016 to 2021,* Attachment 6 – Capital Expenditure", November 2015, p. 6-43

Estimated Cost	$1,321.8 ($000, 2016) capital expenditure (capex).

Consistency with the National Gas Rules (NGR)	The Infrastructure Renewal project complies with the new capex criteria in rule 79 of the National Gas Rules (NGR) because:
	• 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)); and
	• it is justified under rule 79(2)(c) because it is required to:
	  • *maintain and improve the safety of services (rule 79(2)(c)(i))* - making this investment reduces the risk of failure of the critical systems and the risk of security breaches, which could adversely affect the safety of services;
	  • *maintain the integrity of services (rule 79(2)(c)(ii))* - the project reduces the risk that the integrity of the network services will be adversely affected by a failure of either of these critical pieces of infrastructure; and
	  • *comply with a regulatory obligation or requirement (rule 79(2)(c)(iii))* - the project mitigates the risk of a breach of regulatory obligations (e.g. Retail Market Procedure requirements for processing timeframes) if the systems dependent on these critical pieces of infrastructure were not available.

Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Safety and Reliability themes as its implementation will allow AGN to maintain the safety of the network whilst continuing to provide a highly reliable supply of natural gas to our customers by ensuring that reliable, secure, compliant and efficient business processes and systems are maintained. More information detailing the results of AGN's stakeholder engagement program is provided in Chapter 5 of the Access Arrangement Information document.

1.3. Background

Australian Gas Networks Limited (AGN) maintains and operates a number of critical Information Technology (IT) systems that are integral to the efficient and effective management of the Victorian and Albury networks and are required to meet a range of legal and regulatory obligations, including those prescribed in the:

- the National Gas Law (NGL) and National Gas Rules (NGR);
- the Victorian Gas Distribution System Code[4];
- the Victorian Gas Industry Act 2001[5];and
- the Victorian Retail Market Procedures[6] (RMP).

They are also required to meet Energy Safe Victoria's (ESV's) gas and pipeline safety requirements[7].

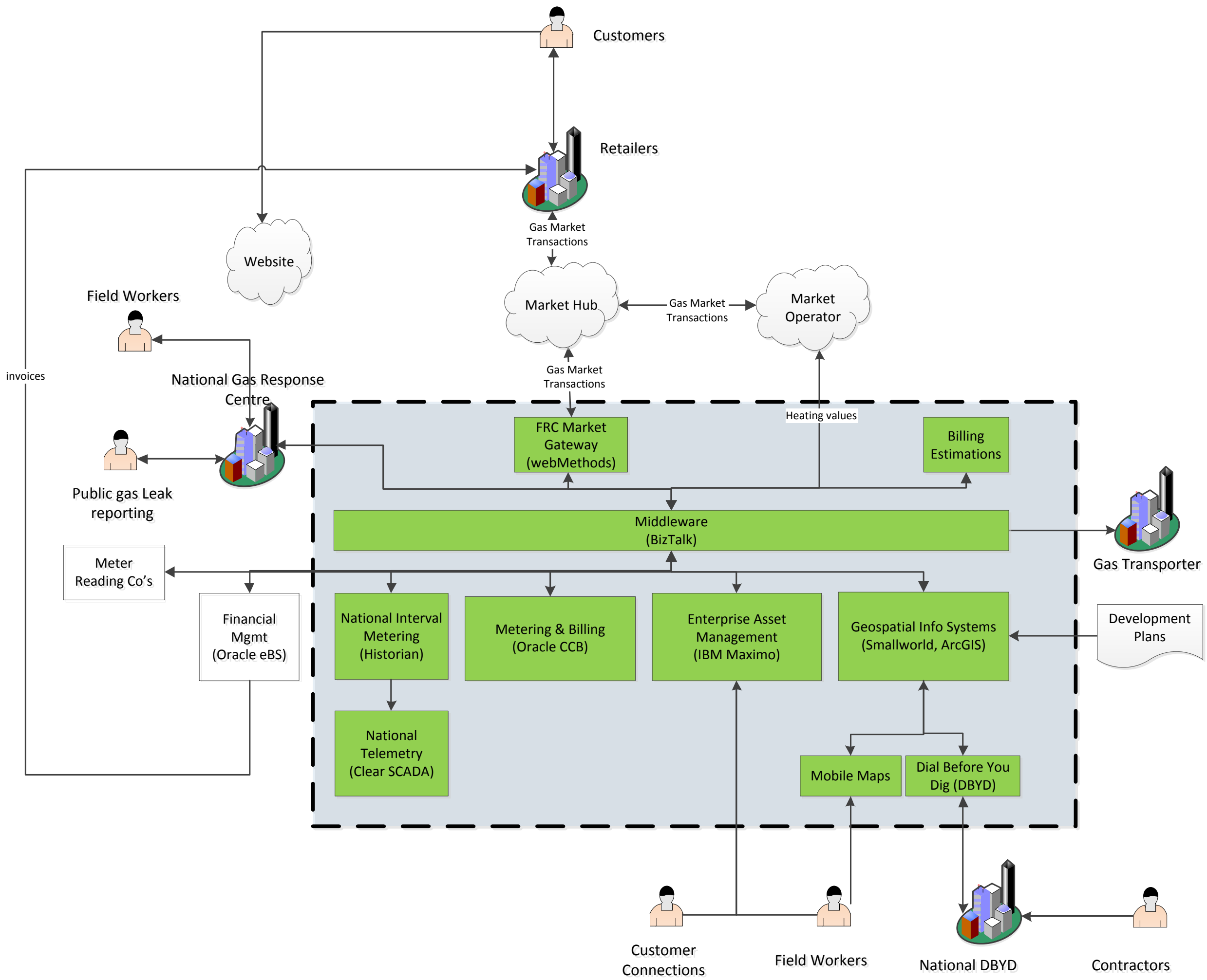
As a prudent operator, AGN has ongoing maintenance plans for its critical IT systems, which are based on the appropriate risk assessments, to ensure continued compliance with these legal, regulatory and safety obligations.

4 Essential Services Commission, "*Gas Distribution System Code*", Version 11.0.
5 http://www.austlii.edu.au/au/legis/vic/consol_act/gia2001167/
6 AEMO, http://www.aemo.com.au/Gas/Policies-and-Procedures/Retail-Gas-Market-Procedures/Victoria
7 http://www.esv.vic.gov.au/About-ESV

1.3.1. AGN's IT environment

Given the highly integrated nature of AGN's IT environment, upgrades and improvements to these systems have been incorporated into a detailed *Information Technology Investment Plan*[8] (IT Plan), which has been provided as Attachment 8.5 to AGN's Access Arrangement Information (AAI) document.

Figure 1: AGN IT Architecture



This IT Plan details the proposed IT capital program of work over the next AA period, as well as acting to support AGN's business objectives, which, in turn, are aligned with the stakeholder expectations identified during the stakeholder engagement program recently undertaken by AGN in Victoria and Albury[9].

In the current AA period, a number of major projects to nationalise and upgrade key IT application systems were implemented. These projects delivered improved IT systems with increased scalability, flexibility and reliability, while also ensuring that AGN continues to meet its obligations under the RMP and other relevant regulatory and customer obligations. The IT systems nationalisation program has so far successfully delivered to Victoria and Albury the

8 APA, *"Victorian and Albury Networks Information Technology Investment Plan for the 2018 to 2022 Access Arrangement Period"*, July 2016

9 Deloitte, *"Australian Gas Networks Customer Insights Report, Victorian and Albury Stakeholder Engagement Program"*, May 2016.

Enterprise Asset Management (EAM) system, the National Metering and Billing (MnB) system and other core foundation platforms to leverage efficiencies in business operations through data consolidation, enablement of standard national processes and task automation.

Additional projects to complete the nationalisation program during the next (2018 to 2022) AA period have been included in separate business cases. The completion of the nationalisation program of work is required in order for AGN to realise the full business benefits from moving towards the national enterprise structure and the integrated suite of systems, including enhanced EAM capability, streamlined and scaled applications and processes, and improved risk mitigation. The ultimate beneficiaries of these improvements will be AGN's customers.

The work proposed in this business case forms part of the national Infrastructure Renewal program across all jurisdictions AGN operates in. The related project for the South Australian AGN network[10] has been recently approved by the AER in its Final Decision for the 2016/17 to 2020/21 AA period[11]. In approving this project, the AER noted that it was *"conforming capex that complies with rule 79 of the NGR"*[12].

1.3.2. Existing IT Infrastructure

The following pieces of AGN infrastructure are approaching the end of their useful lives and are due for renewal in the next AA period:

- *Desktop Infrastructure* **-** The desktop operating platform (Windows 7) is seven years old and is typically refreshed on a 3-7 year cycle with component upgrades on a monthly basis.
- *Telephony Infrastructure* **-** The telephony infrastructure is over five years old and will be due for replacement during the next AA period. Historically, the life span of telephony infrastructure has been around seven years but more recently, it has been reduced to around five years due to the faster changes in technology needing to be accommodated. The increasingly scarce availability of spare parts represents a business risk.

Given the age of this infrastructure, vendor support for the secure operation of desktop and telephony infrastructure cannot be assured.

Not upgrading desktop and telephony infrastructure will prevent AGN from maintaining reliable, secure, compliant and efficient business processes and systems and from preserving the ongoing integrity of services. It will also affect AGN's ability to comply with its regulatory obligations under the various legislative and regulatory instruments set out above, including, amongst others, the RMP (see example in Box 1.1). In addition, the operating business will lose its agility to respond to new challenges because it will be denied access to the latest desktop and telephony facilities.

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[10] AGN, *"Business case SA82 - South Australian Infrastructure Renewal project for the FY2016/17 to FY2020/21 AA period"*, July 2015.

[11] AER, "*Final Decision: Australian Gas Networks Access Arrangement 2016 to 2021, Attachment 6 – Capital expenditure*", May 2016, pg. 6-33.

[12] Australian Energy Regulator, "*Draft Decision: Australian Gas Networks Access Arrangement 2016 to 2021, Attachment 6 – Capital expenditure"*, November 2015, p. 6-43

Box 0.1: AGN's obligations under the Retail Market Procedures

In accordance with Section 1.2 of the Retail Market Procedures, the Australian Energy Market Operator (AEMO) established a Gas Interface Protocol (GIP), which governs the manner and form in which information is to be provided, notice given, notices or documents delivered and requests made as contemplated by the RMP. Further, Section 1.2.4 of the RMP states that AGN is:

- "*bound by, the Gas Interface Protocol in respect of the provision of information, giving of notice, delivery of notices or documents and making of requests, and the receipt of information, notice, notices, documents or requests, as contemplated by these Procedures.*"; and
- "*any failure to use the FRC HUB in accordance with the FRC HUB Operational Terms and Conditions may result in AGN being issued a breach notice.*"

If the breach is found by AEMO to be material, it must be referred to the AER under section 91B of the NGL. This provision in the NGL is a civil penalty provision, which means that the AER can issue an infringement notice[13] and/or **institute civil proceedings** in the Federal Court and seek an injunction or an order that AGN remedy the breach; and/or an order that a penalty be paid.[14]

In addition, Participant Build Pack 3 - FRC B2B System Architecture Section 6, specifically addresses security noting *"An Internet based message service, by its very nature, presents certain security risks… Beyond the requirements herein, participants should make themselves familiar with these risks and institute countermeasures balanced against an assessment of the inherent risks and the value of the asset(s) that might be placed at risk."*

As a prudent operator, AGN has undertaken appropriate risk assessments of the criticality of its IT systems and considers the maintenance of systems to current version minus one to be the most efficient and effective means of ensuring continued compliance with the wholesale market requirements.

As desktop and telephony systems age, it will become increasingly difficult to quickly implement the remedial actions required to resolve a system failure. In a worst-case and increasingly probable scenario, the systems may experience a catastrophic failure and cannot be recovered, resulting in an urgent need of either an upgrade or replacement of that system to restore operations.

1.4. Risk Assessment

The health and safety, operational, customer, compliance and financial risks are summarised below and detailed in Appendix A. Should a failure in the current infrastructure eventuate, these risks would be realised and the consequences magnified unnecessarily because reactive remedial actions take significant time and cost to implement. Furthermore, AGN's management and staff would be under pressure to recover functionality quickly, thereby increasing the risk of error.

If the Infrastructure Renewal project does not proceed, then it will give rise to the following:

- *Health and Safety* - Due to the timeframe of vendor release cycles and the current age of telephony infrastructure, not upgrading the infrastructure will expose AGN to the higher probability of core IT infrastructure being vulnerable to security incidents, which would adversely affect the safety and integrity of services.

13 The maximum infringement notice is $4,000 for individuals ($20,000 for body corporates).

14 The maximum civil penalty is $20,000 for individuals ($100,000 for body corporates), plus $2,000 ($10,000) for every day it continues.

- *Operational* - Strategic application initiatives will be supported by the ageing workstation and telephony systems. This may expose AGN to increasing security risks, particularly if the infrastructure is outside the supported lifecycle. Additionally, efficiencies from new capabilities such as touch screen and modernisation of the corporate desktop will not be realised.
- *Customers* - As described under the Health and Safety and Operational consequences above, there is an increased likelihood of failure in older infrastructure, which could result in unplanned production outages, and slower and inefficient responses to customer calls.
- *Reputation* - AGN's reputation could be damaged in the event of health and safety incidents, unplanned production outages, environmental damage and compromised corporate, staff and customer information and resultant litigation.
- *Compliance* - Catastrophic failure in underlying infrastructure may result in outages of AGN's core IT systems which, in turn, may lead to non-compliance with the RMP and AGN's other regulatory and customer obligations.
- *Financial* - The Health and Safety and Operational consequences summarised above may result in sizeable additional costs. In addition, without the continuation of vendor support that requires upgrades or replacements to maintain currency of the infrastructure, AGN will be forced to find and hire expensive specialists with detailed knowledge of the outdated systems' inner workings.

A summary of the risk assessment is provided in Table 1.3. As this table shows, the overall untreated risk rating is 'High' because the operational and financial risks are high. The full risk assessment results are included as Appendix A to this business case.

Table 1.3: Risk Rating

Risk Area	Untreated Risk Level
Health and Safety	Moderate
Environment	Negligible
Operational	High
Customers	Moderate
Reputation	Moderate
Compliance	Low
Financial	High
Untreated Risk Rating	**High**

1.5. Options Considered

AGN has identified the following options to address the risks outlined in Section 1.4:

- Option 1: Do Nothing; or
- Option 2: Upgrade the desktop and telephony infrastructure in the next AA period.

1.5.1. Option 1 – Do Nothing

Under this option, no upgrades to desktop or telephony infrastructure are implemented during the next AA period.

1.5.1.1. Cost/Benefit Analysis

The benefit of this option is that no upfront capital investment is required. While there are no upfront capital costs associated with this option, the high operational risks associated with this option are likely to result in higher operational costs over the next AA period due to an increased risk of failure in older infrastructure.

The Do Nothing option also gives rise to Health and Safety, Customer, Reputation and Financial risks, which, as noted in Section 1.4, are rated 'Moderate' to 'High'. The risks associated with Option 1 are shown in the Appendix A as the 'Risk Untreated' and summarised in Section 1.4. The overall untreated risk associated with Option 1 is 'High' (see Appendix A) in the next AA period. Based on this risk assessment, it is imperative that the desktop and telephony infrastructure is upgraded in the next AA period. Therefore, the 'Do Nothing' option is not considered a feasible option.

1.5.2. Option 2 – Upgrade the desktop and telephony infrastructure in the next AA period.

The second option that AGN has identified is to upgrade the desktop and telephony infrastructure in the next AA period, which will involve the following.

- *Desktop Infrastructure ("Next Generation Operating Environment work stream")* – this work stream will upgrade all systems to the Windows 10 Operating System from Windows 7. This will provide a robust platform that underpins strategic application initiatives. The platform also allows the business to leverage new capabilities including touch screen, modernisation of the corporate desktop and mobility solution offerings. At the completion of this upgrade, the AGN Victorian and Albury networks will be supported by a robust enterprise desktop platform that aligns to key Enterprise IT systems.
- *Telephony Infrastructure ("Unified Communications work stream")* - will replace legacy telephony hardware with a solution that integrates telephony, presence, voicemail and conferencing across the enterprise. At the completion of this upgrade, AGN's Victorian and Albury networks will be supported by a robust enterprise telephony infrastructure that supports key Enterprise IT systems.

This is the only option that addresses the high risks associated with the failure to upgrade critical IT infrastructure and is consistent with good industry practice and AGN's application lifecycle management methodology (see Appendix C), which assumes that IT applications are supported by an up to date IT infrastructure.

1.5.2.1. Cost/Benefit Analysis

The cost of implementing Option 2 is $1,321.8 ($000, 2016) over the next AA period, as detailed in Section 1.7.3 of this business case.

The key benefit of this option is that the risk of IT infrastructure failure will be substantially reduced and security risks will be addressed by ensuring the security and integrity of the IT environment via a prudent cycle of infrastructure upgrades, to ensure AGN's capabilities are in line with good industry practice.

This option therefore mitigates the risks identified with Option 1 and, in so doing, reduces the overall risk rating from 'High' to 'Moderate' (see Appendix A).[15]

Some of the other specific benefits associated with the two infrastructure upgrades are outlined below:

- *Desktop infrastructure* - Modernisation of the desktop, office and mobility platforms will:
  - reduce AGN's exposure to system and security related vulnerabilities;
  - allow new capabilities to be realised including touch screen and stylus for mobility;
  - provide a modern platform for leveraging new capabilities; and
  - provide for collaboration application and services offerings.
- *Telephony infrastructure* – Upgrading this infrastructure will provide for:
  - a modern, supported, resilient communication and collaboration platform;
  - an integrated and enhanced communications channels across the business; and
  - the capability to leverage future line of business and communication integrations.

If this option is implemented, the overall risk rating will be reduced from 'High' to 'Moderate'.

1.6. Summary of Cost/Benefit Analysis

The summary of costs, benefits and risks of the options considered in this business case is provided below.

Table 1.4: Summary of Cost/Benefit Analysis

Option	Benefits	Costs/Risks
Option 1	No capital investment is required during the next AA period under the 'Do Nothing' option.	High operational and financial risks may lead to higher operational costs over the next AA period if older pieces of IT infrastructure fail or are subject to security breaches, which may result in compromised customer, staff or corporate information.
Option 2	The benefits of the project are that it will: • reduce AGN's exposure to system and security related vulnerabilities and unplanned outages from the failure of critical infrastructure (see Appendix A); • reduce the risk of non-compliance with RMP (see Appendix A); • improve the stability of the IT systems; • provide for core infrastructure to be supported by IT vendors; • integrate and enhance communications channels; • enable compliance with latest IT systems	The cost of implementing this option is $1,321.8 ($000, 2016) capex. The risk rating is reduced from 'High' to 'Moderate'.

15 While the consequence of an event occurring remains the same as in Option 1, the likelihood of the event happening over the next AA period is reduced due to the ongoing prudent cycle of upgrades. This would reduce the overall risk level to 'Moderate', which is considered to be consistent with good industry practice.

with market requirements;

- enable new capabilities to be realised and a greater degree of collaboration to occur through application and services offerings; and
- minimise financial risks.

1.7. Proposed Solution

1.7.1. What is the Proposed Solution?

The proposed solution is Option 2, which will involve the implementation of the following upgrades:

- *Desktop Infrastructure ("Next Generation Operating Environment work stream")* – This work stream will upgrade all corporate systems to the Windows 10 Operating System.
- *Telephony Infrastructure ("Unified Communications work stream")* – This work stream will replace legacy telephony hardware with a solution that integrates telephony, presence, voicemail and conferencing across the enterprise.

1.7.2. Why are we Proposing this Solution?

Option 2 is proposed as it is the most cost effective way of dealing with the risks posed by outdated and unsupported critical infrastructure. It is also consistent with good industry practice.

Implementing Option 2 is also expected to:

- reduce AGN's exposure to system and security related vulnerabilities and unplanned outages from the failure of critical infrastructure;
- improve the stability of the IT systems and enable core infrastructure to be supported by IT vendors;
- minimise financial risk; and
- integrate and enhance communications channels and enable new capabilities to be realised through applications and service offerings.

At the completion of this upgrade AGN's Victorian and Albury networks will be supported by a robust enterprise desktop platform and telephony infrastructure that aligns to key Enterprise IT systems, the benefits of which will be passed onto consumers.

1.7.3. Forecast Cost Breakdown

1.7.3.1. Methodology and approach

Because the Infrastructure Renewal is a national project, the total project cost is estimated based on the work that needs to be carried out across all Australian jurisdictions that AGN operates in. The total project cost is then allocated to state-specific AGN networks based on the customer numbers across each of the networks, to ensure that the cost allocations used reflect how AGN ultimately allocates costs to customers served from these networks. As at 31 December 2015, Victoria and Albury accounted for 51.35% and 1.79% of AGN's total customer numbers, respectively.

The approach that AGN has used to estimate the total project cost and its proposed approach to carrying out the work is based on the same approach used in the South Australian business case "SA82 Infrastructure Renewal" project for the FY2016/17 to FY2020/21 AA period, which was approved by the AER in its Final Decision and is outlined below:

- AGN uses an industry standard B&T Project Methodology, which is managed through formal governance. This B&T Methodology divides the projects into key stages – concept, develop, plan, deliver and close. Each stage consists of key tasks and activities to ensure the consistency and standardisation across projects. The project methodology is outlined in Appendix C.
- To ensure project estimates are developed in a consistent manner, AGN utilises an Estimation Tool, which is aligned with the B&T Project Methodology. This estimation tool has been used to forecast the work and cost estimates for the infrastructure upgrade program of work. This estimation tool utilises historic figures from the current AA period for resource work effort estimates. All historic figures are checked for reasonableness to ensure any changes to the way historical projects were carried out were taken into account. The work effort estimates are based on a complexity matrix tool, which uses a series of questions to categorise projects into simple, medium and complex.
- The material and direct labour costs, and applicable planning, design and commissioning charges, are based on historic actual costs of similar projects and on vendor quotes subject to a competitive tendering process in accordance with the APA Procurement policy and guidelines.[16] Resource Unit Costs (both internal and external) are based on research, where actual placement costs have been used based on historical project resources and current resourcing rates (2016).
- The historic figures and work effort estimates are used as inputs into the final estimates, which are subject to stringent review and endorsement by members of the IT Estimates Review Committee. The work effort, cost and timing of projects are monitored throughout the project lifecycle to ensure on time and on budget delivery.
- When implementing the project, AGN will use a formalised Project Methodology and utilise a combination of internal and external resources to deliver the program of work. The Project Methodology is outlined in Appendix C and provides a consistent, standard and quality assured project implementation framework, ensuring that the work is carried out in a prudent and efficient manner.

1.7.3.2. Cost summary

The costs that are forecast to be incurred over the next AA period and the cost breakdown by upgrade project, cost category and between the Victorian and Albury networks are provided in Tables 1.6 to 1.8. These costs were estimated from the 'bottom-up' using a standard IT cost model and the approach outlined above. These costs have also been reviewed and endorsed by members of the IT Estimates Review Committee. The detailed cost breakdown by individual project is provided in Appendix B.

As these tables show, the upgrades will be implemented during the two-year period from 2018 to 2019, due to the timing related to the equipment lifecycle timeframe and to ensure the most efficient testing regime of the workstation and Standard Operating Environment (SOE) upgrades.

Table 1.6: Capex/Opex Split ($000, 2016)

[16] Available upon request

	2018	2019	2020	2021	2022	Total
Capex	839.6	482.3	-	-	-	1,321.8
Opex	-	-	-	-	-	-
Total	**839.6**	**482.3**	**-**	**-**	**-**	**1,321.8**

Note: Totals may not exactly match the sum of individual costs due to rounding.

Table 1.7: Project Cost Estimate, by Work Stream ($000, 2016)

	2018	2019	2020	2021	2022	Total
Next Generation Desktop	559.7	321.5	-	-	-	881.2
Unified Communications	279.8	160.8	-	-	-	440.6
Total	**839.6**	**482.3**	**-**	**-**	**-**	**1,321.8**

Note: Totals may not exactly match the sum of individual costs due to rounding.

Table 1.7: Project Cost Estimate, by Cost Type ($000, 2016)

	2018	2019	2020	2021	2022	Total
Direct Labour	87.1	58.1	-	-	-	145.2
Contracted Labour	348.6	232.4	-	-	-	580.9
Hardware, Software and Maintenance	403.9	191.8	-	-	-	595.7
Travel, Sundry, Other	-	-	-	-	-	-
Total	**839.6**	**482.3**	**-**	**-**	**-**	**1,321.8**

Note: Totals may not exactly match the sum of individual costs due to rounding.

Table 1.8: Capex Split Between Victoria and Albury ($'000, 2016)

	2018	2019	2020	2021	2022	Total
Capex – Victoria	811.3	466.0	-	-	-	1,277.3
Capex - Albury	28.3	16.2	-	-	-	1,321.8
Total	**839.6**	**482.3**	**-**	**-**	**-**	**1,321.8**

1.7.4. Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN considers the forecast capex for this project to be:

- *Prudent* – The expenditure is necessary in order to maintain the safety and integrity of services and comply with regulatory obligations and requirements and as such, is of a nature that a prudent service provided would incur.

- *Efficient* – The Infrastructure Renewal project will enable AGN to maintain its operational efficiency and address the risks of non-compliance with AGN's legislative and regulatory obligations. It will also reduce the risks of customer and business interruptions and corresponding adverse financial and reputation impacts. Additionally, the manner in which AGN intends to carry out the upgrade (i.e. by using a combination of internal and external resources to deliver the program of work and using the Project Management Office to provide guidance and governance to the project) is consistent with good industry practice and can be considered efficient. The expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.
- *Consistent with accepted good industry practice* – The Infrastructure Renewal project will ensure that AGN continues to operate in line with good industry practice, in terms of having all critical hardware and software up to date and supported by vendors.
- *Achieves the lowest sustainable cost of delivering pipeline services* – The Infrastructure Renewal project is necessary to mitigate the risks associated with operating on older versions of the software and hardware with the resultant performance and cost implications should these pieces of infrastructure fail and is therefore consistent with the objective of achieving the lowest sustainable cost of service delivery.

The capex can therefore be viewed as being consistent with rule 79(1)(a) of the NGR.

The proposed capex is also justifiable under rule 79(2)(c) because it is necessary to:

- *maintain and improve the safety of services (rule 79(2)(c)(i))* – making this investment reduces the risk of failure of the critical systems or security breaches, which could adversely affect the safety of services;
- *maintain the integrity of services (rule 79(2)(c)(ii))* – the project reduces the risk the integrity of the network services will be adversely affected by a failure of either of these critical pieces of infrastructure; and
- *comply with a regulatory obligation or requirement (rule 79(2)(c)(iii))* – the project mitigates the risk of a breach of regulatory obligations if the systems were not available (e.g. RMP requirements for processing timeframes).

Appendix A Risk Assessment

The risk assessments below demonstrate the change in risk profile associated with the two options considered in this business case. As noted in Section 1.4 if the periodic upgrades to the AGN's infrastructure are not implemented, the risk of catastrophic failure increases year-on-year, and is assessed as 'High' during the next AA period.

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Option Risk
Risk Untreated Option 1	**Likelihood**	*Possible*	*Unlikely*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	**HIGH**
	Consequence	*Medium*	*Insignificant*	*Significant*	*Medium*	*Medium*	*Minor*	*Significant*	
	Risk Level	*Moderate*	*Negligible*	*High*	*Moderate*	*Moderate*	*Low*	*High*	
Residual Risk Option 2	**Likelihood**	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	**MODERATE**
	Consequence	*Medium*	*Insignificant*	*Significant*	*Medium*	*Medium*	*Minor*	*Significant*	
	Risk Level	*Moderate*	*Negligible*	*Moderate*	*Moderate*	*Moderate*	*Low*	*Moderate*	

Appendix B Detailed Cost Estimate

The tables below set out the costs of upgrading the Desktop and Telephony infrastructure. The costs in these tables are expressed in real 2016 values.

Next Generation Desktop

IT & ICT Procurement Estimations Template: B&T Projects		
Project Name:	Next Generation Desktop	
Project Complexity:	Medium	
Project Type:	Upgrade	
Estimations Summary		
Total Project (end to end)	Effort (Days)	Cost ($ 2016)
End to End Total	259	$440,613
Estimations by Project Stage		
Develop Stage Total	38	$204,512
Plan Stage Total	81	$90,059
Deliver Stage Total	128	$133,220
Cost Stage Total	12	$12,822

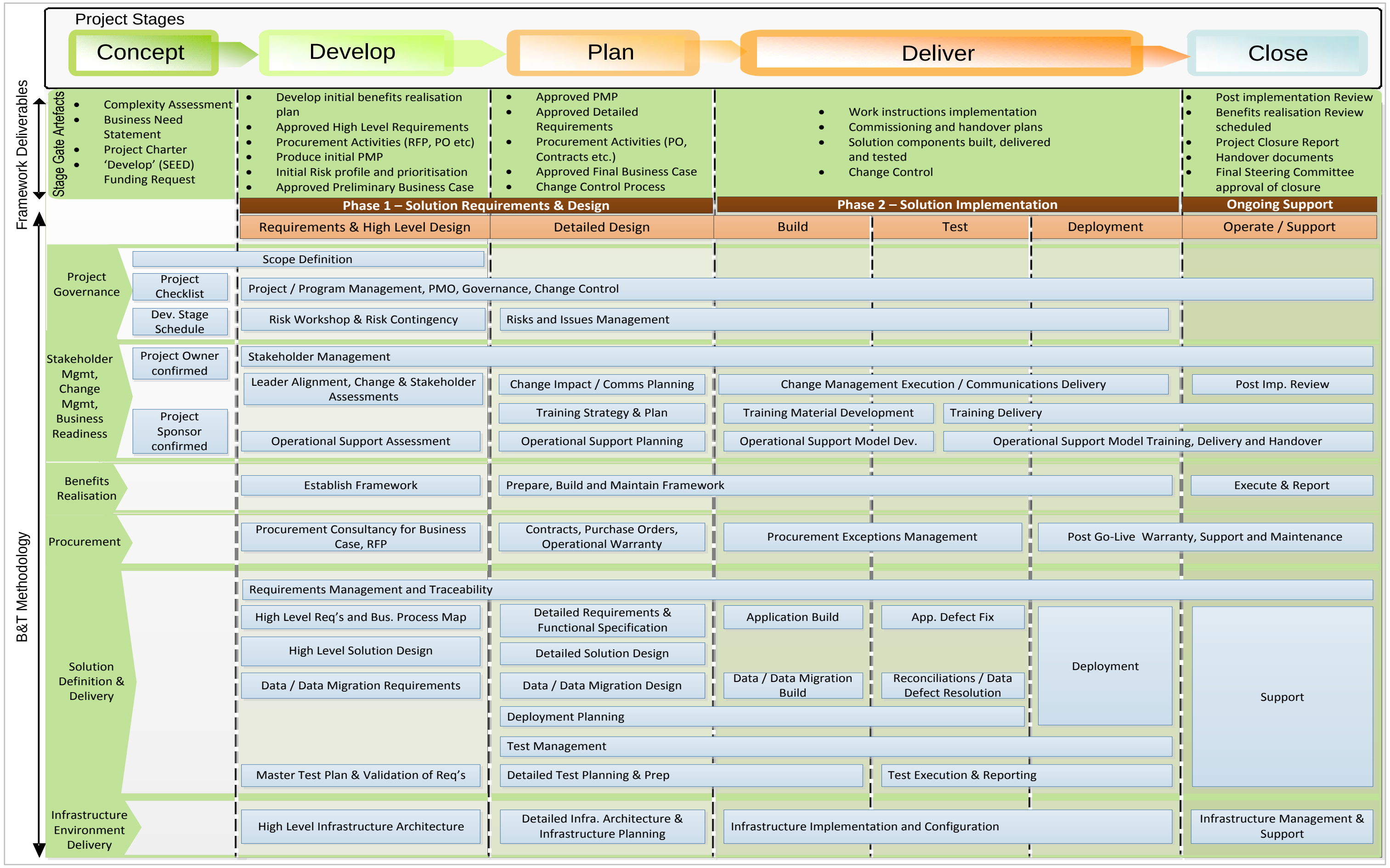
Unified Communications

IT & ICT Procurement Estimations Template: B&T Projects		
Project Name:	Unified Communications	
Project Complexity:	Medium	
Project Type:	Upgrade	
Estimations Summary		
Total Project (end to end)	Effort (Days)	Cost ($ 2016)
End to End Total	314	$881,223
Estimations by Project Stage		
Develop Stage Total	60	$618,349
Plan Stage Total	95	$100,086
Deliver Stage Total	148	$149,645
Cost Stage Total	12	$13,143

Appendix C Methodologies

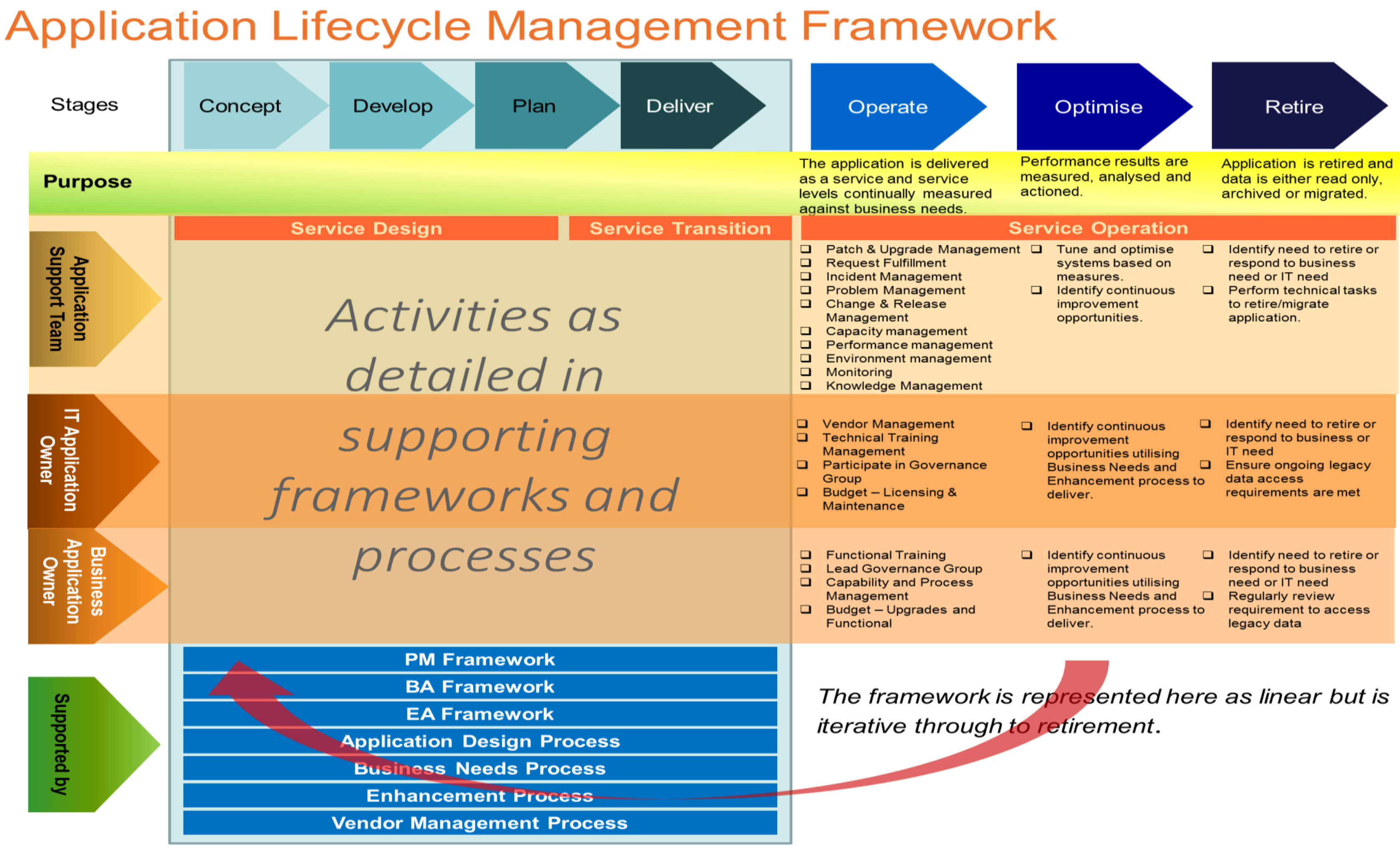
AGN Project Methodology

To manage all its IT projects, AGN utilises an industry standard Business and Technology (B&T) Project Methodology, which is managed through formal governance. The key aspects of this methodology are outlined in the diagram below.



AGN Application Lifecycle Management

AGN utilises an industry-standard application lifecycle management methodology and a practical framework to determine upgrade timelines and priorities for both IT applications and the underlying IT infrastructure. The diagram below outlines the key aspects of this framework.



Business Case – Capex V104

Development of Digital Capabilities

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	Jin Singh, Marketing & Communications Manager
Approved By	Andrew Staniford, Chief Operating Officer

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	The work proposed in this business case forms part of the National development of AGN's Digital Capabilities[1]. The South Australian (SA) component of this project has been recently approved by the Australian Energy Regulator (AER) in its final decision on AGN's Access Arrangement (AA) for the 2016/17 to 2021/22 AA period[2] . Digital technology has become an integral part of daily life with more consumers and businesses choosing to seek information, transact and communicate through digital channels. Customer expectations for access to digital solutions are now the expected norm for doing business today. AGN's current systems for digital communications are outdated (or in some cases, non existent) and do not provide the means to be able effectively communicate with the community which directly impacts on customer expectations being met. AGN are committed to rectifying this over the next regulatory period by developing and upgrading AGN's digital capabilities, ultimately bringing AGN in line with other utility businesses that have digital strategies in place and meet AGN's customer expectations. This Business Case follows on as the Victorian capex component to that approved by the AER in the recent SA Access Arrangement.
Options Considered	The following options have been considered to address the risks posed by outdated digital communications: • Option 1: Do Nothing • Option 2: Development of AGN's digital platform for Victoria and Albury
Proposed Solution	Option 2 has been selected which will see the development of AGN's digital platform for Victoria and Albury to ensure the effective delivery of online digital services and communications for customers and stakeholders. AGN engaged Isobar, a digital specialist agency, through a competitive tender process, to analyse its current capabilities and customer gas connection journey.

[1] AGN, "Access Arrangement 2016-21 proposal", Attachment 7.1_Business Cases.pdf, "Business case SA84 – Development of AGN's Digital Capabilities project for the FY2016/17 to FY2020/21 AA period", July 2015.

[2] AER, "Final Decision: Australian Gas Networks Access Arrangement 2016 to 2021, Attachment 6 – Capital Expenditure", May 2016, pg. 6-42.

	Isobar's research and analysis was the basis of the Digital Roadmap document which is included as an appendix to this business case.
Estimated Cost	The proposed capex cost of the project over the AA period is $1,371 ($2016, $000).
Consistency with the National Gas Rules (NGR)	The development of AGN's digital platform in Victoria and Albury complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because: • 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)). • it is justified under 79(2)(c) as it is required to maintain the integrity of services (79(2)(c)(ii)).
Stakeholder Engagement	AGN has undertaken a comprehensive engagement program to better understand the values of our stakeholders and customers. During this engagement, customers told us that they would like to access more information from AGN and favour digital channels. Customers would also like AGN to be more visible, believing it would improve their experience as customers. The development of AGN's digital platform is considered to be consistent with these customer insights and provides a solution for customers to access all information across all topics via AGN's website.
Supporting Information	• V104 Supporting Information 1: ISOBAR Proposal (confidential) • V104 Supporting Information 2: Technical Audit (confidential) • V104 Supporting Information 3: Industry Landscape Audit (confidential) • V104 Supporting Information 4: Situational Analysis (confidential) • V104 Supporting Information 5: Digital Vision (confidential)

1.3. Background

1.3.1. AER's South Australian Final Decision

The work proposed in this business case forms part of AGN's national Development of Digital Capabilities project, being undertaken across all jurisdictions in which AGN operates.

The South Australian (SA) component of this project has been recently approved by the AER for the 2016/17 – 2020/21 AA period. In approving this project, the AER found the following:

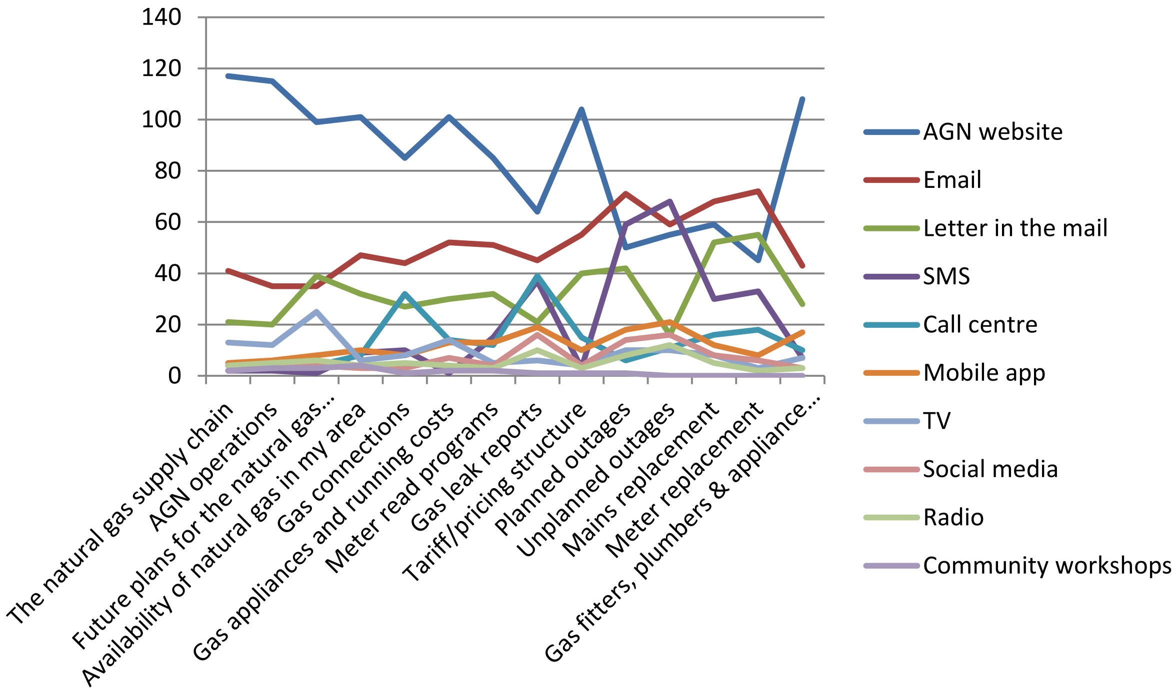
> *"This project is to establish a digital platform for AGN to deliver online digital services and communications for customers and stakeholders. AGN, through its customer engagement program, found that stakeholders were not satisfied with its digital presence. AGN engaged consultants to develop a strategic plan for its online presence, which AGN is implementing with this project. AGN submitted that this capex is necessary to maintain the integrity of its services. This project is for all of AGN's businesses nationally. The costs proposed by AGN represent 36 per cent of the national costs. AGN's South Australian network has approximately 36 per cent of AGN's customers. We are satisfied that its proposed capex is conforming capex that complies with rule 79 of the*

NGR. We have therefore included AGN's proposal for its Development of Digital Capabilities project in our alternative capex estimate."[3]

1.3.2. Customer Expectations & Stakeholder Engagement

AGN developed a comprehensive stakeholder engagement program designed to better understand the values of our stakeholders and customers and support the development of our South Australian Access Arrangement. During this AGN found that stakeholders and customers expect more from AGN in terms of our digital presence with the majority of customers preferring to communicate with AGN through digital channels (see table below). Participants in AGN's SA program chose the AGN website as their preferred method of communication, followed in order by email, letter, sms, call centre, mobile app, TV, social media, radio and lastly community workshops.

Figure 1.1: SA Customer Communication Preferences[4]



Similarly, findings from our Victorian and Albury engagement program were consistent with our SA customers, with Victorian and Albury customers telling us that they would like to access more information from AGN and favour digital channels. Customers would also like AGN to be more visible, believing it would improve their experience as customers.

For example, our customers told us that they would like to access more information from AGN and favour digital channels with the AGN website ranked number one for preferred customer communication channels.

[3] AER, "*Draft Decision: Australian Gas Networks Access Arrangement 2016 to 2021*", Attachment 6 – Capital Expenditure, page 6-42.
[4] Deloitte, *"Australian Gas Networks Customer Insights Report, Victorian and Albury Stakeholder Engagement Program"*, May 2015.

Figure 1.2: Victoria/Albury Customer Communication Preferences[5]

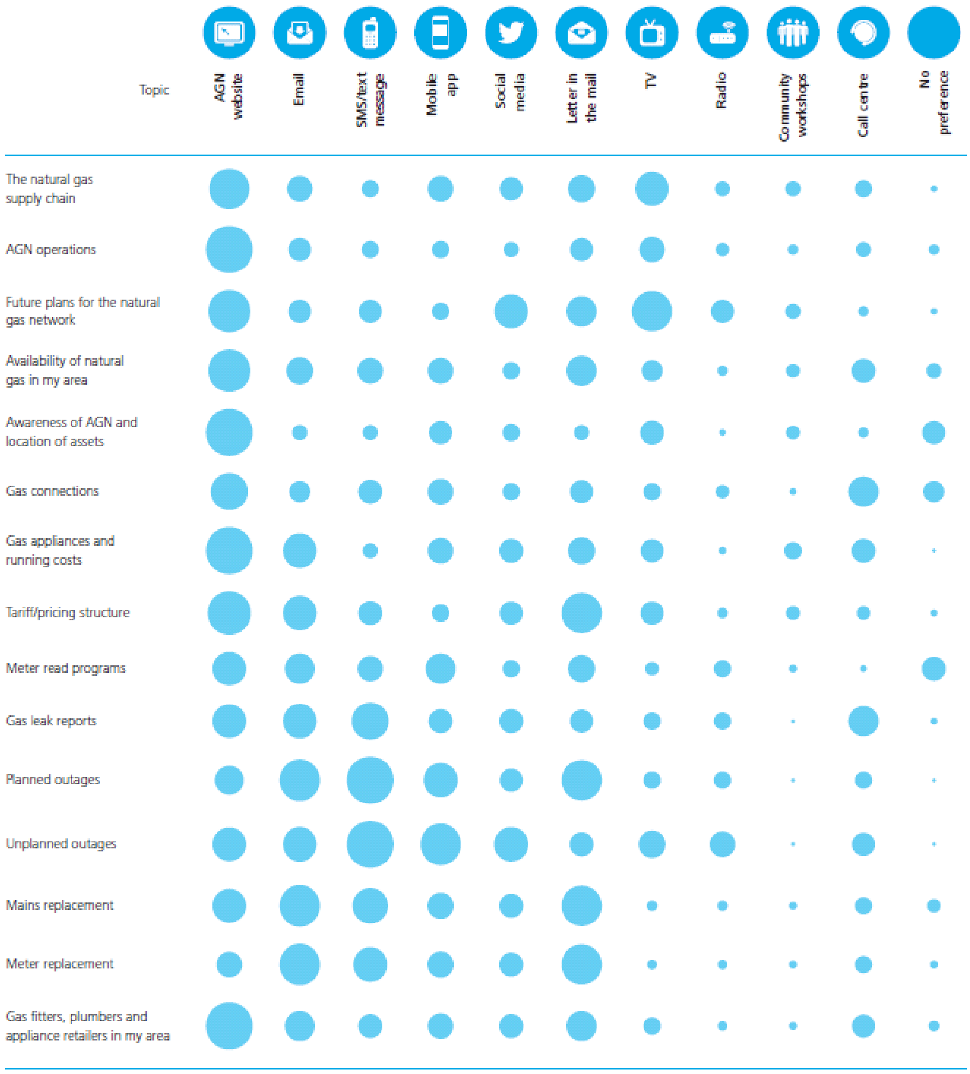


Table 3: Customer communication preferences

The findings from the stakeholder engagement program are also consistent with findings from market research that has been conducted periodically on behalf of AGN by McGregor Tan Research and Harrison's Research.

In the latest McGregor Tan Research (April 2015), 50% of respondents that recalled AGN's advertisements stated they would go to the internet to get more information. This was followed by 20% "go to a shop", 13% "telephone", 3% other, 18% "don't know" and "wouldn't get more information". 86% from age groups 18-29, 67% from age groups 30-39 and 70% from age groups 40-49 stated they would go to the internet to get more information.

Building digital capabilities will improve customer and stakeholder interactions with AGN by automating processes and bringing information together that is currently situated on various AGN owned websites and also stakeholder websites.

5 Deloitte, *"Australian Gas Networks Customer Insights Report, SA Stakeholder Engagement Program"*.

More information detailing the results of our stakeholder engagement program is provided in Chapter 3 of our Access Arrangement Information document.

1.3.3. AGN's Current Digital Capabilities

AGN engaged ISOBAR to conduct a technological audit in 2014 to assess AGN's capabilities in comparison to the capabilities of other businesses in the industry.

For example, results from this audit found that other utility companies[6] in Australia and the UK had digital processes that linked with systems so that customers could access information and transact more readily online. Two key transactions were around gas availability and requesting and tracking a gas connection. The audit also found that AGN had no social media presence while most other like companies did. Lastly, the use of video to explain AGN's role and the gas connection process was also lacking when compared to like organisations. These results are summarised in Table 1.3 below.

Table 1.3: Risk Rating

	Australian Gas Networks	Jemena	Norther Gas Networks	Wales and West Utilities	SA Power Networks	AGL	Origin Energy	Energy Australia
Real Time Content	No	Yes	No	Yes	Yes	Yes	Yes	Yes
YouTube	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Facebook	No	No	Yes	Yes	Yes	Yes	Yes	No
Twitter	No	Yes	Yes	No	Yes	Yes	Yes	Yes
Online Transactions	No	Yes	No	Yes	Yes	Yes	Yes	Yes
Website Video Content	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Chat	No	No	No	No	No	Yes	No	No
Linked-In	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes

1.4. Risk Assessment

Table 1.4: Risk Rating

Risk Area	Untreated Risk Level
Health and Safety	Moderate
Environment	Negligible
Operational	High
Customers	Moderate
Reputation	Moderate
Compliance	Moderate
Financial	High

6 For example, Jemena, SA Power Networks www.sapowernetworks.com.au, Energy Australia www.energyaustralia.com.au, Northern Gas www.northerngasnetworks.co.uk, Wales and West Utilities www.wwutilities.co.uk.

Untreated Risk Rating	High

The key risks posed by AGN's current website are the following:

Operational – this risk area has been rated as High because uncorrected deficiencies and poor integration between systems may result in inefficient work order and connection request processing, an inability to make spatial and logical queries, and operational risks of errors in manual data processes compared to electronic communications and confidential information being compromised.

Financial – this risk area has been rated as High because failure to act increases risk. In addition to will result in sizeable additional costs and compromised staff and customer data could lead to significant litigation costs. In addition, without the continuation of IT vendor support, AGN will be forced to find and hire expensive IT specialists with detailed knowledge of the outdated systems' inner workings and the programming language used. Financial penalties may also be imposed for not complying with Retail Market Procedures or other regulatory obligations.

1.5. Options Considered

AGN has identified the following options to address the risks outlined in Section **Error! Reference source not found.** and support AGN's business objectives:

- Option 1: Do Nothing; or
- Option 2: Development of AGN's digital platform for Victoria and Albury.

1.5.1. Option 1 – Do Nothing

Option 1 is not considered feasible due to the significant risks associated with not upgrading applications.

AGN's digital capability needs to be brought up to date with current expectations and digital channel usage trends. It is clear through stakeholder engagement and market research that the majority of customers expect information, transactions and communication on line. For AGN to maintain its ability to maintain customer services in the current age it needs to update its digital capabilities and ensure the integrity of its services.

Additionally, AGN's applications are reliant on each other to allow high volumes of transactions to flow from one IT system to another, if required upgrades are not implemented, the risk increases year-on-year. Additionally, this program reduces the risk of integration between systems not working as required and maintaining the levels of systems security and integrity of services.

The do nothing approach will significantly impact on AGN's customer's experience/interaction with AGN.

1.5.2. Option 2 – Development of Digital Platform for Victoria and Albury

This Option will see the development of AGN's digital platform for Victoria and Albury that will ensure the delivery of secure online digital services and communications for customers and stakeholders.

In order to maximise the effectiveness of this investment and deliver better customer service, Isobar have identified a need for a step increase in investment to provide the necessary functionality. The scope for work associated with this incremental spend is addressed in the Isobar Digital Road Map proposal.

Additionally, the development of this project will integrate into the Geospatial Information Systems to enable online functionality to make an "Is Gas in My Street?" enquiry and also will integrate into the Maximo EAM system to enable one function to request and track a gas inlet connection.

On completion of this project, the Victorian and Albury Networks business will be supported by a secure new website and digital services and channels as per AGN's SA Network.

1.5.2.1. Cost/Benefit Analysis

This project will deliver a 24/7 customer service channel that can effectively communicate to customers, industry partners and stakeholders, and be an important communication channel – either facilitating connections or processing orders for gas connections with the aim of delivering an improved customer experience and a speedier gas connection journey.

In particular, this project seeks to address the recommendations provided by ISOBAR in their technological audit.

1.5.2.2. Cost/Benefit Analysis

- Better customer service and experience
- Ability to grow digital capability to match customer expectations/behaviours
- The risk of not proceeding will leave AGN exposed to not being able to maintain the integrity of its services to customers as use of technology for communications and transactions have changed significantly.

The benefits of this option are detailed below:

Consolidated Website

The consolidation of 5 websites will mean that only one website will need to be maintained. This will mean that information will be up to date and consistent, with commensurate efficiencies realised through a simplified support and maintenance structure and improved life cycle development, updating and website management.

This will result in a simplified customer journey which will reduce confusion about AGN as all information will be on one website branded as Australian Gas Networks.

There will also be advantages in terms of search engine optimisation.

Customer Reporting

Website monitoring in terms of search rankings, time on pages, search terms within website, user journey, popular content will be monitored to enable refinements more regularly.

Content Management System (CMS)

The implementation of a secure, user friendly CMS will mean that subject matter experts within each area will be able to update the content of the website without going to a digital agency. This will result in quicker updating of the website. The constraints with the existing system were highlighted in the recent Port Pirie/Whyalla in SA outage (changes could only be made with assistance from the contractor hosting the web site, at times the contractor was available).

Service Delivery Channels

The AGN website will be the key digital service delivery channel. This project will deliver a better layout, a more logical menu structure, better user journey and improved content for our key audiences. It will also be mobile and tablet responsive inline with web user behaviour.

The new website will also be on a flexible digital platform that will enable it to keep up with technological changes.

Digital service delivery will increase with the delivery of new digital customer channels such as Web Chat, email/sms alerts, Twitter and Facebook. These channels will assist AGN communicate to the community in the method they prefer. It will also allow AGN to communicate more regularly and cost efficiently than using traditional paid media channels such as press, tv and radio. AGN will be able to communicate a range of messages to its audiences using social media channels and also email/sms alert registrations. It will be able to help customers with web enquiries in near real time through web chat functionality.

Online Transactions through systems integration

Two key online transactions for customers dealing with AGN include gas availability queries to their area of residence and gas connection requests. Both these transactions would require integration with AGN IT systems. Customers will benefit from being able to conduct these transactions at a time that suits them and also have information about the industry partners that can be involved in the entire process from main to flame (energy retailers, gas appliance retailers, gas appliance installers, plumbers, builders).

Online Tracking of Gas Connection request status

The gas connection process can be complex. This functionality will enable the customer to see what stage their gas connection is at and provide direction for what needs to be done once the AGN inlet has been connected. This will improve customer service.

The proposed capex cost of the project over the AA period is $1,371 ($2016, $000)

1.6. Summary of Cost/Benefit Analysis

Table 1.5: Summary of Cost/Benefit Analysis

Option	Benefits	Costs/Risks
Option 1 Do nothing	No investment required	High operational risks, which will result in higher costs over the longer term if IT systems become unstable, fail or are subject to security breaches. Doing nothing also gives rise to Customer, Reputation and Compliance risks which are rated as Moderate, with the overall untreated risk being High. Moreover, if this situation extends beyond the next AA period, the risk will increase to 'Extreme'
Option 2	Consolidated website and simplified customer journey Content Management System (CMS) – secure, user friendly CMS Online Transactions through systems integration Online Tracking of Gas Connection request status	Capex cost of the project over the AA period is $1,371 ($2016, $000) but reduces the risk rating to Moderate

Reduces the level of risk

1.7. Proposed Solution

1.7.1. What is the Proposed Solution?

Option 2 (i.e. the improvement of AGN's Digital Capabilities) is the proposed solution.

1.7.2. Why are we Proposing this Solution?

We are proposing this solution as we consider the improvement of our Digital Capabilities is necessary in order to ensure we maintain the integrity of the services we provide and that our capabilities are in line with good industry practice.

1.7.3. Forecast Cost Breakdown

As this is a national project, AGN has allocated a portion of the total project costs to our Victorian and Albury networks, based on a customer number allocation as at 31 December 2015.

As a result, 51.35% of the project costs have been allocated to Victoria, with 1.79% of the costs allocated to Albury.

Table 1.6 below provides a summary of these costs.

Table 1.6: Forecast Capex ($2016, $000)

	2018	2019	2020	2021	2022	Total
Victoria	$708.86	$616.2	$0	$0	$0	$1324.9
Albury	$24.7	$21.4	$0	$0	$0	$46,182
Total	$733.3	$637.7	$0	$0	$0	$1,371.0

This forecast cost over the next AA period, is based on the cost estimate provided by ISOBAR (a digital specialist agency), which AGN engaged through a competitive tender process in order to analyse our current capabilities and customer gas connection journey.

Isobar's research and analysis was the basis of the Digital Roadmap document which is included as an appendix to this business case.

The Digital Roadmap has three key phases:

- 6+ months: Analysis and recommendation (completed)
- Years 1-2: Establish a foundation platform that meets current needs and industry benchmarks. This platform has the capabilities to be adapted for future needs (in progress)
- Years 3+: Digitisation of key customer transactions within the connection process. Focus will be on key systems integration and process improvements to allow for digital connection transactions.

1.7.4. Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN considers the forecast capex for this project to be:

- *Prudent* – the expenditure is necessary in order to maintain the integrity of services. AGN has seen strong customer support for digital channels for communications. AGN's current five web-sites are perceived by customers as being complex and unwieldy. This project will establish a more focused web site, and provide management tools to assess and improve utilisation, to more effectively meet the needs of consumers. It will also provide a platform to use other digital tools as they become available to improve customer service and in particular offer near real time access to gas leak, safety and emergency information. The expenditure is therefore prudent and necessary to maintain the integrity of network services provided by AGN.
- *Efficient* – the recommended project will allow AGN to meet its objectives of operational efficiency as outlined in its IT Strategic Plan AGN is currently hosting five web-sites. Consolidating these into one web-site will improve operational effectiveness. It will also provide a platform to enable future digital technologies, in line with identified customer preferences. In the longer term this will improve customer service and operational efficiency. A failure to invest in these systems will constrain operational efficiencies able to be achieved by AGN.
- *Consistent with accepted good industry practice* – the review undertaken by Isobar demonstrated that other energy distribution networks have invested in digital assets and tools. The functionality of AGN's current assets is well below those of other leading distributors. It is also clear that all industries through the wider economy are investing in digital assets. This project will establish digital assets in AGN consistent with those that have been adopted in other energy distribution businesses, and is consistent with current accepted and good industry practice.
- *Achieves the lowest sustainable cost of delivering pipeline services* – consumers are shifting to becoming a digital economy. This is driven by the rising demand by customers for 24/7 access to information. This demand is being fanned by improvements in technology, whereby information can be disseminated quickly to relevant audiences. Companies that do not invest in technology to improve access to information will be increasingly overlooked by digital consumers. It is therefore essential that network providers invest in these assets. This will be necessary to achieve gas connection retention and growth. If investment is not made, it is likely that customers will find the connection process too cumbersome and will be less likely to connect to, or use, natural gas. Any reduction in connection rates because of a failure to provide a digital capability will increase the costs of providing services. To ensure that AGN continues to achieve the lowest cost of delivering sustainable services, it will need to develop digital assets. The use of digital services will also provide other benefits including the provision of improved data for decision making.

The capex can therefore be viewed as being consistent with rule 79(1)(a) of the NGR. The proposed capex is also consistent with rule 79(1)(b), because the expenditure is necessary to:

- *maintain and improve the safety of services (rule 79(2)(c)(i))* – building AGN's digital capabilities is vital for AGN to provide its core services as customers expect to be able to interact quickly and securely with AGN through digital channels.

Appendix A – Risk Assessment

The risk assessments below demonstrate the change in risk profile associated with the two options considered in this business case. As noted in Section **Error! Reference source not found.**, if the periodic upgrades to the AGN's critical IT applications are not implemented, the risk of catastrophic failure increases year-on-year, and is assessed as 'High' during the next AA period. Moreover, if this situation extends beyond the next AA period, the risk will increase to 'Extreme'.

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Option Risk
Risk Untreated Option 1	**Likelihood**	*Possible*	*Unlikely*	*Occasional*	*Possible*	*Possible*	*Possible*	*Possible*	**HIGH**
	Consequence	*Medium*	*Insignificant*	*Significant*	*Medium*	*Medium*	*Medium*	*Significant*	
	Risk Level	*Moderate*	*Negligible*	*High*	*Moderate*	*Moderate*	*Moderate*	*High*	
Residual Risk Option 2	**Likelihood**	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	**MODERATE**
	Consequence	*Medium*	*Insignificant*	*Significant*	*Medium*	*Medium*	*Minor*	*Significant*	
	Risk Level	*Moderate*	*Negligible*	*Moderate*	*Moderate*	*Moderate*	*Low*	*Moderate*	

Appendix B – Detailed Cost Estimate

The cost breakdowns and project details can be found in the Isobar Digital Road Map included as Attachment B.

National	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Opex	$360,000	$945,000	$840,000	$840,000	$840,000	$840,000	$840,000
Capex	$615,000	$935,000	$1,380,000	$1,200,000	$0	$0	$0
Total	$975,000	$1,880,000	$2,220,000	$2,040,000	$840,000	$840,000	$840,000
OPTION 1: VICTORIAN NETWORKS ONLY							
Vic Only	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Opex	$184,860	$485,258	$431,340	$431,340	$431,340	$431,340	$431,340
Capex	$315,803	$480,123	$708,630	$616,200	$0	$0	$0
Total	$500,663	$965,380	$1,139,970	$1,047,540	$431,340	$431,340	$431,340
OPTION 2: ALBURY NETWORK ONLY							
Albury Only	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Opex	$6,444	$16,916	$15,036	$15,036	$15,036	$15,036	$15,036
Capex	$11,009	$16,737	$24,702	$21,480	$0	$0	$0
Total	$17,453	$33,652	$39,738	$36,516	$15,036	$15,036	$15,036
OPTION 3: VICTORIAN AND ALBURY NETWORKS							
Vic + Albury	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Opex	$191,304	$502,173	$446,376	$446,376	$446,376	$446,376	$446,376
Capex	$326,811	$496,859	**$733,332**	**$637,680**	$0	$0	$0
Total	$518,115	$999,032	$1,179,708	$1,084,056	$446,376	$446,376	$446,376

Augmentation Business Cases

Business Case	Capex Value ($2016)
V13 Gate Station Rebuilds	$2m
1 Supporting Information 1: 09 114.1.01 Occupational Noise Assessment – Gas Regulating Installations	
2 Supporting Information 2: AEMO Correspondence dated 11 May 2016, Sale Minimum Connection Pressure	
3 Supporting Information 3: APA ES 4098	
V18 H85 Echuca	$0.5m
V23 Dandenong Crib Point Pipeline Augmentation	$14m
V28 H07 Cranbourne	$9m
V54 Dandenong to Crib Point Pipeline - Refurbishment	$2m
1 Supporting Information 1: V04 Refurbishment of Dandenong to Crib Point Pipeline - Envestra Business Case (AA 2013-17)	
2 Supporting Information 2: NPV and Options Analysis	
V89 Morwell Tramway Road TP	N/A
1 Supporting Information 1: Correspondence from ESV	
V102 H70 Moe	$0.2m
V103 H79 Wallan	$0.3m

Note: Supporting Information files have been provided separately.

Business Case – Capex V13

Gate Station Rebuilds

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	Robert Davis, *Manager Field Operations*
Approved By	Andrew Foley, *General Manager Victorian Networks*

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	Natural gas is delivered into AGN's distribution network via city gates or district regulator stations. Major work at three city gate stations (Berwick, Lindrum Road and Sale) is required in the next Access Arrangement (AA) period to deal with load growth, residential encroachment and changes in inlet conditions in the network. If this work is not undertaken, then station capacity will be exceeded and the safe and reliable delivery of gas may be compromised due to low gas temperatures and/or low delivery pressure. Under the Victorian Distribution System Code (Code), AGN has a regulatory obligation to: • use all reasonable endeavours to ensure the minimum pressure is maintained at supply points; and • connect customers that are within the minor or infill extension area. Compliance with the Code is a condition of AGN's Gas Distribution Licence. AGN also has a regulatory obligation under the *Environment Protection Act 1970* and subsidiary State Environment Protection Policy – Control of Noise from Industry, Commerce and Trade (No. N-1) to ensure that environmental noise limits are not exceeded. Upgrading the three facilities is required to comply with these regulatory obligations. It is also required to maintain and improve the safety of services and maintain the integrity of services.
Options Considered	The following options have been considered to deal with the issues outlined above: 1 Option 1: Do nothing 2 Option 2: Maintain the current configuration of the network either by: a Ring-fencing the network, and not allowing further connections past the network's capacity; or b Implementing a demand management program. 3 Option 3: Upgrade the Berwick, Lindrum Road and Sale gate stations.
Proposed Solution	Option 3 has been selected because it is the most effective way of complying with the

	regulatory obligations associated with gas delivery in Victoria.
Estimated Cost	The forecast capital expenditure for Option 3 is $2,384k (real $2016).
Consistency with the National Gas Rules (NGR)	The proposed upgrade to the three stations complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because: • it is necessary to maintain and improve the safety of services, maintain the integrity of services and comply with a regulatory obligation (rules 79(2)(c)(i),(ii) and (iii)); 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	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Reliability and Safety themes as its implementation will allow AGN to maintain the safety of its network while continuing to provide a highly reliable supply of natural gas to its customers by completing major works on three transmission stations with ongoing load growth, or changes in inlet conditions in the network. More information detailing the results of AGN's stakeholder engagement program is provided in Chapter 5 of the Access Arrangement Information document.
Supporting Information	• Supporting Information 1 – 09 114.1.01 Occupational Noise Assessment – Gas Regulating Installations • Supporting Information 2 – AEMO Correspondence dated 11 May 2016, Sale Minimum Connection Pressure • Supporting Information 3 - APA ES 4098

1.3. Background

The safe delivery of natural gas into a distribution network is mediated by gate and district regulator stations. These facilities ensure that stable outlet pressures are maintained and gas temperatures remain within specification. These facilities are designed, operated and maintained in accordance with the relevant standards and regulations, which include AS2885 (Pipelines – Gas and Liquid Petroleum), the Victorian Gas Distribution Code (the Code) and the *Environment Protection Act 1970* and subsidiary State Environment Protection Policy – Control of Noise from Industry, Commerce and Trade (SEPP N-1)[1].

The capacity of a station can be exceeded as a result of new connections (load growth) or a change in inlet conditions. If the capacity is exceeded, it may result in:

- excessive gas velocities in the pipework, which can give rise to excessive noise and result in damage to the facility, OHS noncompliance for employees maintaining the gate station and noncompliance with EPA noise policy;
- excessive pressure losses within pipework, which can result in outlet pressures not being maintained; and
- gate station heaters being unable to maintain inlet temperatures, which can result in outlet temperatures falling below the design level.

[1] Supporting Information 5 - State Environment Protection Policy (Control of Noise From Industry, Commerce and Trade) No. N-1, as varied 31/10/2001

In each of these cases the facility would not be working safely as required by AS 2885 and the Code, and remediation works would be required.

Where outlet pressure falls below the design delivery pressure, pressures at the fringe of the network may fall below the recommended level. The recommended Victorian network design minimum pressure conditions are taken from Schedule 1 Part A of the Code, which requires a Distributor to use all reasonable endeavors to *"ensure the minimum pressure is maintained at the distribution supply point."* In high pressure networks in Victoria the minimum pressure is 140 kPa.

AGN also has a regulatory obligation under the Code to connect customers that are within the minor or infill extension areas. Specifically, clause 3.1(c) of the Code states that:

> *"A Distributor must connect the gas installation of a customer that resides within the minor or infill extension area on fair and reasonable terms and conditions."*

Compliance with the Code is a condition of AGN's Gas Distribution License. The requirement to connect and to use reasonable endeavors to ensure the minimum pressure is maintained can therefore be viewed as a regulatory obligation. [2]

Sites approaching capacity and requiring upgrade are identified as part of the regular facility review process or as operating conditions change. Three sites have been identified as requiring upgrade within the next AA period to address capacity issues. Further detail on these stations/regulators can be found in Appendix A.

1.3.1. Berwick City Gate

The Berwick City Gate Supplies [redacted] customers and is currently subject to excessive gas flow leading to high gas velocities in the pipework. The velocity limit as specified in the APA Engineering Standard ES 4098[3] is 30m/s and the current calculated maximum gas velocity at this site is 110m/s. [redacted] In order to reduce the noise, the station will need to be upgraded by installing larger pipework with quieter regulators housed in an enclosure. Residential encroachment has led to a higher likelihood of noise complaints.

1.3.2. Sale City Gate

Supplies [redacted] customers. The upstream service provider for the Sale City Gate (AEMO) has advised AGN that the inlet pressures can no longer be maintained above the contract minimum of 5,000 kPa (refer to Supporting Information 2). At the revised minimum inlet pressure, work is required to guarantee sufficient flow capacity of the gate station to meet existing downstream demand. Current flow capacity of the gate station is not sufficient to ensure downstream network fringe pressures remain above the design minimum in a scenario of high gas usage and low inlet pressure (at contract minimum).

[2] Failure to comply with the Code may result in a range of actions by the Essential Services Commission (ESC) as outlined in its Compliance Policy Statement for Victorian Energy Businesses.

[3] V13 Supporting Information 6 - APA ES 4098

[4] Supporting Information 1 – 09 114.1.01 Occupational Noise Assessment – Gas Regulating Installations

1.3.3. Lindrum Road Field Regulator

Supplies [redacted] customers. Excessive pressure losses within pipework at the Lindrum Road Field Regulator have resulted in insufficient pressure at the regulator inlet to adequately maintain supply at the fringes of the downstream network. Larger pipework and regulators must be installed for the site to provide sufficient capacity to the downstream network.

1.4. Risk Assessment

The untreated risks associated with this project are summarised in Table 1.3. Further detail on the risk assessment is provided in Appendix B to the Business Case.

Table 1.3: Risk Rating

Risk Area	Untreated Risk Level
Health and Safety	High
Environment	High
Operational	Moderate
Customers	Moderate
Reputation	Moderate
Compliance	High
Financial	High
Untreated Risk Rating	**High**

As this table shows, the untreated risk associated with the three gate stations is 'High' because the health and safety and compliance related risks have been rated as 'High'.

Health and safety risks are considered high in this case because ongoing connections to the network that results in gate station capacity being exceeded will result in transient gas outages, which will increase in frequency and extent year on year. These outages will not be evenly distributed across the network but instead will manifest at the fringe of the network. There is the potential for an outage to result in release of un-combusted natural gas from a burner, leading to accumulation in a confined space followed by fire, explosion or asphyxiation. In extreme cases the result could be the loss of several lives.

The compliance and Environment related risks have been rated as High because:

- [redacted]
- the failure to use all reasonable endeavours to *"…ensure the minimum pressure is maintained at the distribution supply point"* would constitute non-compliance with the Code.

[5] Supporting Information 1 – 09 114.1.01 Occupational Noise Assessment – Gas Regulating Installations.

Operational, customer and reputational risks have been rated as Moderate because if there is a transient gas outage and it results in appliances (including hot water, general heating and cooking) failing to function, it will likely lead to Guaranteed Service Level (GSL) payments, complaints, adverse public comments about AGN and potentially lead to ombudsman complaints or litigation.

1.5. Options Considered

AGN has considered the following options to deal with the risks posed by the Berwick, Lindrum Rd and Sale sites:

1 Option 1: Do nothing.

2 Option 2: Maintain the current configuration of the network (i.e. without augmentation) by either:

   a ring-fencing the network and not allowing further connections once the network's capacity is reached; or

   b implementing a demand management program.

3 Option 3: Upgrade the three gate stations.

Further details on each of these options are provided below.

1.5.1. Option 1 – Do Nothing

The first option that AGN has identified is to do nothing. Under this option, AGN will continue to accept network connections (as it is required to do under the Code) but do nothing to address the effect on outlet pressure at the gate stations, or the potential failure of these facilities.

1.5.1.1. Cost/Benefit Analysis

The benefit of this option is that it does not give rise to any upfront capital costs. This option would, however, result in the probability of low outlet pressures or failure of the facility increasing year on year. The option will therefore result in AGN failing to comply with its regulatory obligations to use all reasonable endeavours to *"ensure the minimum pressure is maintained at the distribution supply point".*

It would also result in:

- *Reduced security of supply* – Connected customers towards the fringe of the network will not be able to make use of the gas supply that they have paid for. Not all customers will be impacted equally, creating an inequitable supply privilege gradient where customers closer to the gate get a better level of service at the expense of customers at the network fringe. This is inconsistent with the intent of the gas regulatory framework (including the AA framework), which is designed to ensure that all customers are treated equitably and are provided with access on a non-discriminatory basis.
- *Increased chance of gas intrusion into non-ventilated areas* – A gas network that is not operating correctly or predictably is an unsafe network. A transient loss of gas gives rise to the risk of the free release of un-combusted gas, as operating gas appliances do not necessarily respond to loss of gas by automatically turning off. As free gas is released there is the potential for it to collect in a confined space and eventually catch fire or explode, which poses a risk to human health and safety and property. Doing nothing to address the risk of gas intrusion is inconsistent with Australian Standard AS4645 (Gas Distribution Network

Management), which states that these types of risk should be managed to as low as reasonably practicable.

- *Higher noise output from station* [redacted]

The increased risk of an outage under this option also increases the likelihood that AGN will have to make GSL payments (these payments can range from $150-$300 per affected customer depending on the length of the interruption - potential total around $150,000) and incur costs relighting customers, with the cost of a relight being [redacted] per relight for the Berwick City Gate and Lindrum Road Field Regulator and [redacted] per relight for the Sale City Gate (higher due to regional location).

Given the risks and costs posed by this option and the fact that it would result in AGN failing to comply with its regulatory obligations under the Code, SEPP N-1 and Australian Standard AS4645, this is not considered a feasible option.

1.5.2. Option 2 – Maintain the Current Configuration of the Networks

Another option that AGN has considered is to try and maintain the current configuration of the network and not carry out any reinforcement. To avoid a sustained breach of the network design minimum pressure with the network in its current configuration, either the rate of load increase must be reduced to zero, or the existing load must be reduced. The options for achieving this include:

- ring-fencing the network and not allowing further connections once the network's capacity is reached; or
- implementing a demand management program.

1.5.2.1. Cost/Benefit Analysis

Like option 1, the benefit of this option is that it does not give rise to any upfront capital costs. However, for the reasons set out below, maintaining the current configuration of the network through ring-fencing or demand management is **not** considered a feasible option:

- *Ring-fencing the network* **-** This option is arguably the most direct method of ensuring ongoing supply to the existing customer base. However, this option would result in AGN contravening its regulatory obligation to connect customers that are within the minor or infill extension areas.
- *Demand management* **-** There is **no** plausible level of demand management that would offset the rate of connection in this network given the expected growth. The three gate stations are predominantly residential areas with no significant commercial customer that could load shed.

The risks associated with this option are the same as those associated with Option 1, which is High.

1.5.3. Option 3 – Upgrade City Gates

The third option that AGN has considered involves upgrading the Berwick, Lindrum Rd and Sale stations. All stations will require at least larger pipework and new regulators to be installed while maintaining supply to the downstream network. As pipework will need to be replaced where there is currently no bypass, it will be necessary to build a new regulating station in parallel to the existing station. The existing regulator stations will then be removed from the site once the new station has been commissioned.

The program of work for the gate station upgrades and forecast cost is set out in the table below. It is based on deliverability using existing engineering resources and risk of delaying work. Delays to the Berwick work bring increased risk of noise complaints and associated fines and are therefore prioritised first.

Table 1.4: City Gate Upgrade Program of Works ($000, 2016)

	2018	2019	2020	2021	2022
Berwick City Gate	$449	$449			
Lindrum Road Field Regulator			$344	$344	
Sale City Gate				$399	$399

1.5.3.1. Cost/Benefit Analysis

This option has been estimated to cost $2,384 ($000, 2016) (see Appendix C). The benefits of this option are that it will:

- ensure compliance with AGN's network pressure and customer connection regulatory obligations under the Code and the noise related obligations under the SEPP N-1;
- maintain the safety of services by reducing the risk of gas intrusion on the distribution network to as low as reasonably practicable as required by Australian Standard AS4645; and
- maintain the integrity of services by ensuring the minimum pressure is maintained at the distribution supply point.

The residual risk arising under this option is set out in Appendix B. In short, if this project is implemented it will result in the residual risk rating falling from High to Negligible.

1.6. Summary of Cost/Benefit Analysis

Table 1.4: Summary of Cost/Benefit Analysis

Option	Benefits	Costs/Risks
Option 1	Avoids up front capital expenditure	While there are no direct costs associated with this option, the risks to human health and safety and compliance related risks associated with this option are High (see untreated risks in Table 1.3). Implementing this option would also result in AGN failing to comply with its regulatory obligations under the Code (i.e. to use all reasonable endeavors to ensure minimum delivery pressures are maintained) and the *Environment Protection Act 1970* and subsidiary State Environment Protection Policy – Control of Noise from Industry, Commerce and Trade (No. N-1). This option is therefore not considered a feasible option.
Option 2	Avoids up front capital expenditure	Like Option 1 there are no direct costs associated with this option but for the following reasons maintaining the current configuration of the networks is not considered a feasible option: • Not allowing further connections to the network would be contrary to the obligation that AGN has under the Code to connect customers; and • There is no plausible way that demand management could offset the expected growth in connections. The residual risk under this option will be same under this option as the untreated risk set out in Table 1.3, which is High.
Option 3	The benefits of this option are that it: • Ensures AGN complies with the pressure and connection provisions in the Code and the *Environment Protection Act 1970* and subsidiary State Environment Protection Policy – Control of Noise from Industry, Commerce and Trade (No. N-1). • Maintains the safety of services, by reducing the risk of gas intrusions and risk to human health and safety to as low as reasonably practicable. • Maintains the integrity of services. Reduces the residual risk from High to Negligible	Capital costs $2,384k (real $2016).

1.7. Proposed Solution

1.7.1. What is the Proposed Solution?

The proposed solution is Option 3, which will involve upgrading the Berwick City Gate, Lindrum Rd Field Regulator and Sale City Gate stations.

1.7.2. Why are we Proposing this Solution?

Option 3 has been selected because options 1 and 2 are not feasible and because it is the only way of complying with the regulatory obligations under the Code and the SEPP N-1, maintaining and improving the safety of services and maintaining the integrity of services.

1.7.3. Forecast Cost Breakdown

A detailed cost breakdown is included in Appendix C and is summarised in the following table:

Table 1.5: Project Cost Estimate

	2018	2019	2020	2021	2022	Total
Capex	449	449	344	743	399	2,384
Opex	-	-	-	-	-	-
Total	**449**	**449**	**344**	**743**	**399**	**2,384**

The detailed cost breakdown has been prepared for individual items based on the actual incurred costs of comparable projects recently completed, including the Cobram City Gate and Melrose Drive Field Regulator upgrades, and the City Gate installation at Thewlis Road, Pakenham. These projects were competitively tendered and are similar in scope. Theses 3 project were significant upgrades or new construction of gate stations and were completed during the current AA period. This shows that the 3 proposed upgrades can be completed in similar timeframe to the recently completed work.

1.7.4. Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN considers the forecast capex for this project to be:

- *Prudent* – The proposed expenditure is necessary to maintain the integrity of those parts of the networks supplied via the Berwick, Lindrum Rd and Sale stations. It is also necessary to comply with regulatory obligations and to reduce the risk to human health and safety posed by gas outages to as low as reasonably practicable. The proposed expenditure is also of a nature that a prudent service provider would incur as highlighted by the options analysis that has been conducted.
- *Efficient* – The proposed upgrade of the three gate stations is the most cost effective way of addressing the capacity issues posed by growth in those parts of the network serviced by these gate stations. The proposed expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur. The manner in

which AGN intends to carry out the work (i.e. field work to be carried out by an external contractor that has demonstrated specific expertise in completing the installation of the assets in a safe and cost effective manner and that will be selected through a competitive tender) can also be considered efficient.

- *Consistent with accepted good industry practice* – Complying with the obligations set out in the Code and in the SEPP N-1 by carrying out the proposed upgrade is consistent with accepted and good industry practice. So too is reducing the risk to human health and safety posed by gas outages to as low as reasonably practicable in a manner that balances cost and risk as required by Australian Standard AS4645 (Gas Distribution Network Management).
- *Achieves the lowest sustainable cost of delivering pipeline services* – Proactively addressing emerging gas supply issues will avoid multiple reactive measures, thereby ensuring the lowest long-term sustainable cost for customers.

The capex can therefore be viewed as being consistent with rule 79(1)(a) of the NGR.

The proposed capex is also consistent with rule 79(1)(b), because the expenditure is necessary to:

- *maintain and improve the safety of services (rule 79(2)(c)(i))* - by improving the environment in which are employees work (noise) and improve the reliability of supply.
- *maintain the integrity of services (rule 79(2)(c)(ii))* - by ensuring assets are operated with established design standards.
- *comply with a regulatory obligation (79(2)(c)(iii))* - by limiting the noise output of our gate stations.

Appendix A Station Technical Details

Table A.1 Station Technical Details

	Berwick City Gate	Sale City Gate	Lindrum Road Field Regulator
Licence Number	217	43	49
Location	Clyde Road, Berwick	South Gippsland Highway, Sale	Lindrum Road, Frankston
Asset Number	P4-088	P8-014	P4-013
Year Constructed	1977	1969	1973
Inlet MAOP (kPa)	6,890	6,890	1,920
Outlet MAOP (kPa)	515	4,800	515
Supply Network	Berwick – Hampton Park Distribution Network	Longford to Sale Transmission Pipeline	Frankston Distribution Network
Number of Customers Supplied	[redacted]	[redacted]	[redacted]

Figure A.1 – Berwick City Gate

Figure A.2 – Sale City Gate

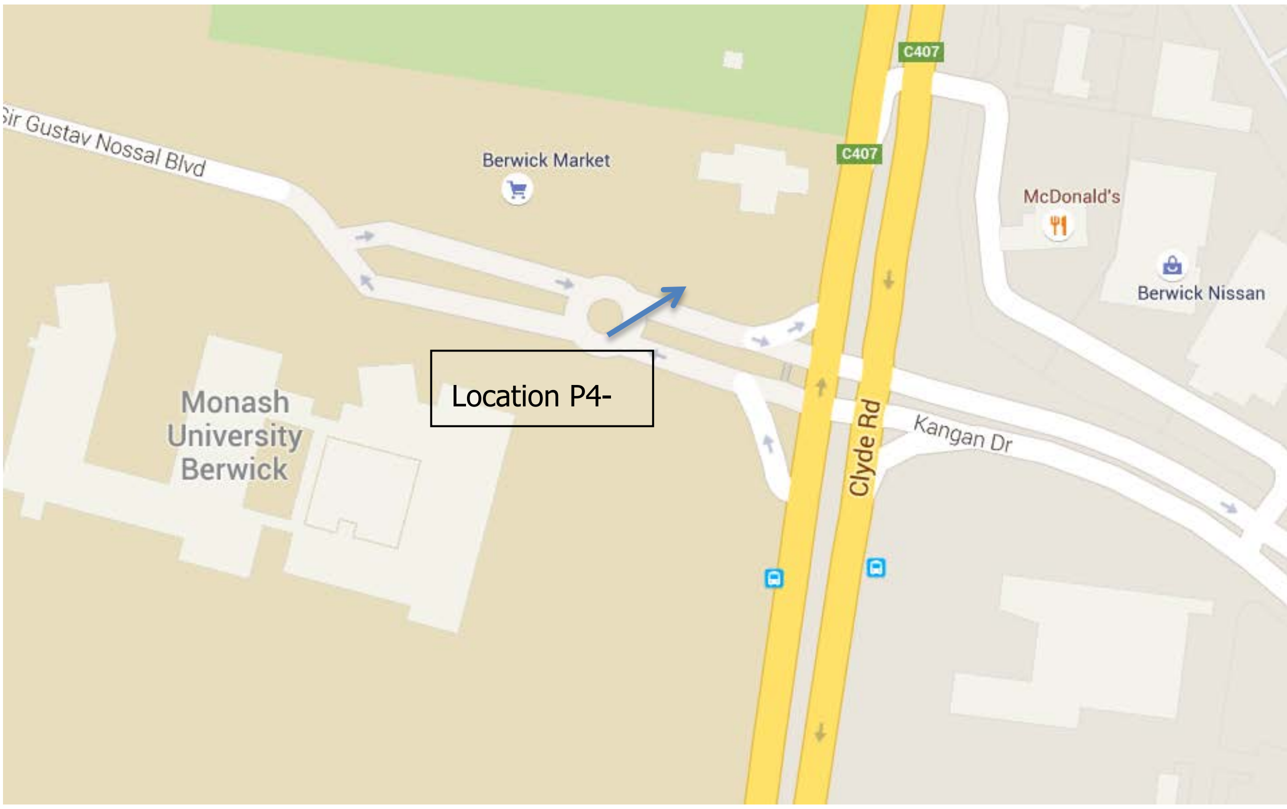
Figure A.3 – Lindrum Road Field Regulator

Appendix B Risk Assessment

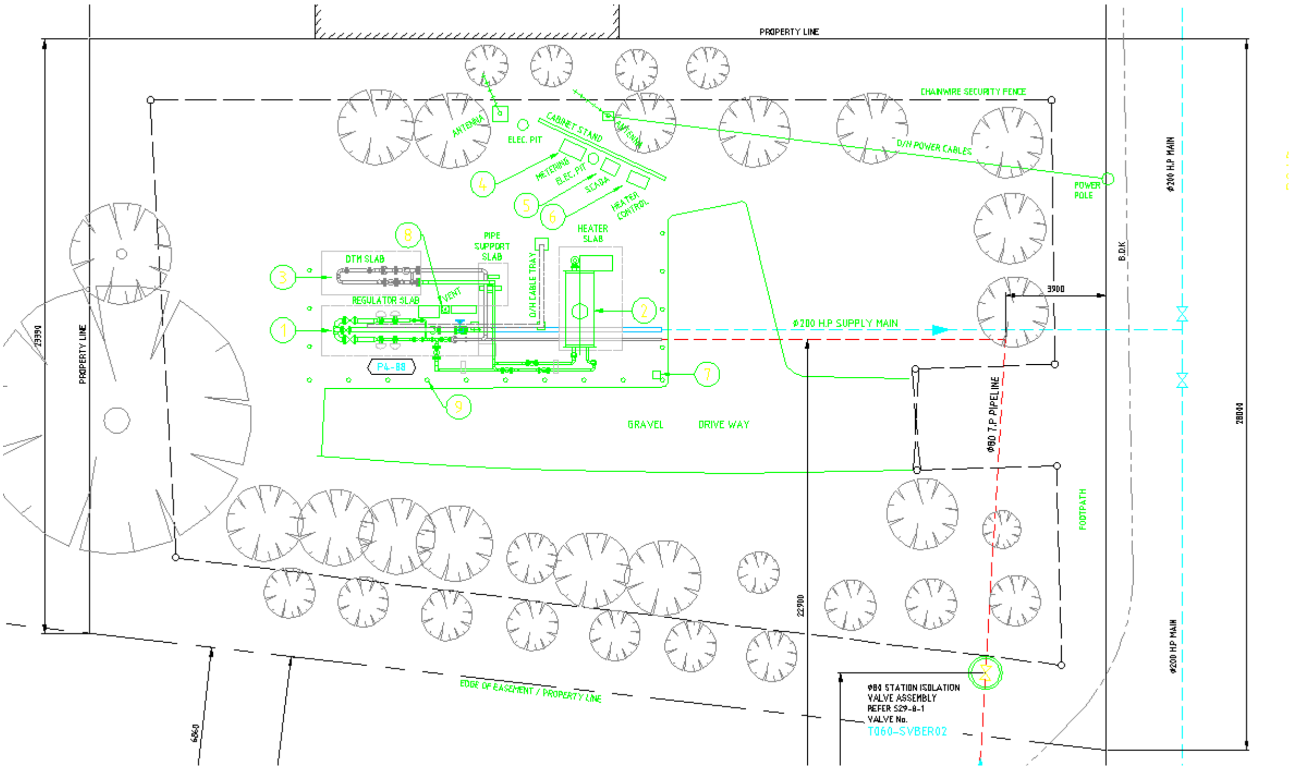
		Health & Safety	Environment	Operational	Customer	Reputation	Compliance & Legal	Financial Impact	Total Option Risk
Risk Untreated	**Likelihood**	Possible	Possible	Possible	Possible	Possible	Possible	Possible	
	Consequence	Significant	Significant	Medium	Medium	Medium	Significant	Significant	
	Risk Level	*High*	*High*	*Moderate*	*Moderate*	*Moderate*	*High*	*High*	*High*
Residual Risk Option 1	**Likelihood**	Possible	Possible	Possible	Possible	Possible	Possible	Possible	
	Consequence	Significant	Significant	Medium	Medium	Medium	Significant	Significant	
	Risk Level	*High*	*High*	*Moderate*	*Moderate*	*Moderate*	*High*	*High*	*High*
Residual Risk Option 2	**Likelihood**	Possible	Possible	Possible	Possible	Possible	Possible	Possible	
	Consequence	Significant	Significant	Medium	Medium	Medium	Significant	Significant	
	Risk Level	*High*	*High*	*Moderate*	*Moderate*	*Moderate*	*High*	*High*	*High*
Residual Risk Option 3	**Likelihood**	Rare	Rare	Rare	Rare	Rare	Rare	Rare	
	Consequence	Insignificant	Insignificant	Insignificant	Insignificant	Insignificant	Insignificant	Insignificant	
	Risk Level	*Negligible*	*Negligible*	*Negligible*	*Negligible*	*Negligible*	*Negligible*	*Negligible*	*Negligible*

Appendix C Detailed Cost Breakdown

P4-088 Berwick City Gate, Cranbourne Rd, Berwick, 3806



Site Layout: P4-088



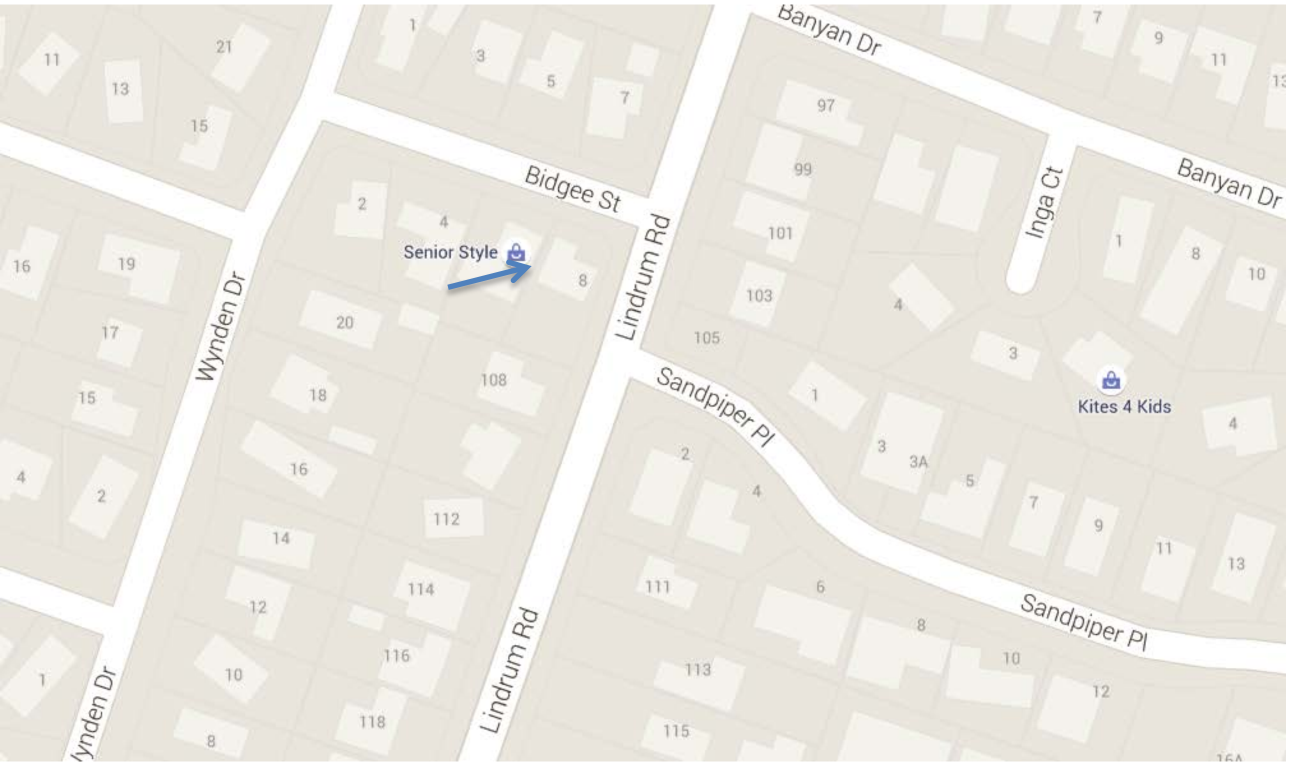
Project Scope:

- Design and Planning – detailed designs for new regulator kiosk which will meet network gas capacity requirements and environment noise restrictions and obtaining consent to construct and operate from Energy Safe Victoria (ESV).
- Procurement – through tendering process, procurement of the regulation kiosk.
- Installation – using internal and external resources, tie in the new regulation kiosk.
- Commissioning of the facility by AGN operations personnel.
- Decommission and remove existing regulator skid from site.
- Facility drawing – update all drawings to reflect changes
- Asset management system – update Maximo asset management system with changes and ensure preventative maintenance program meets AGN requirements

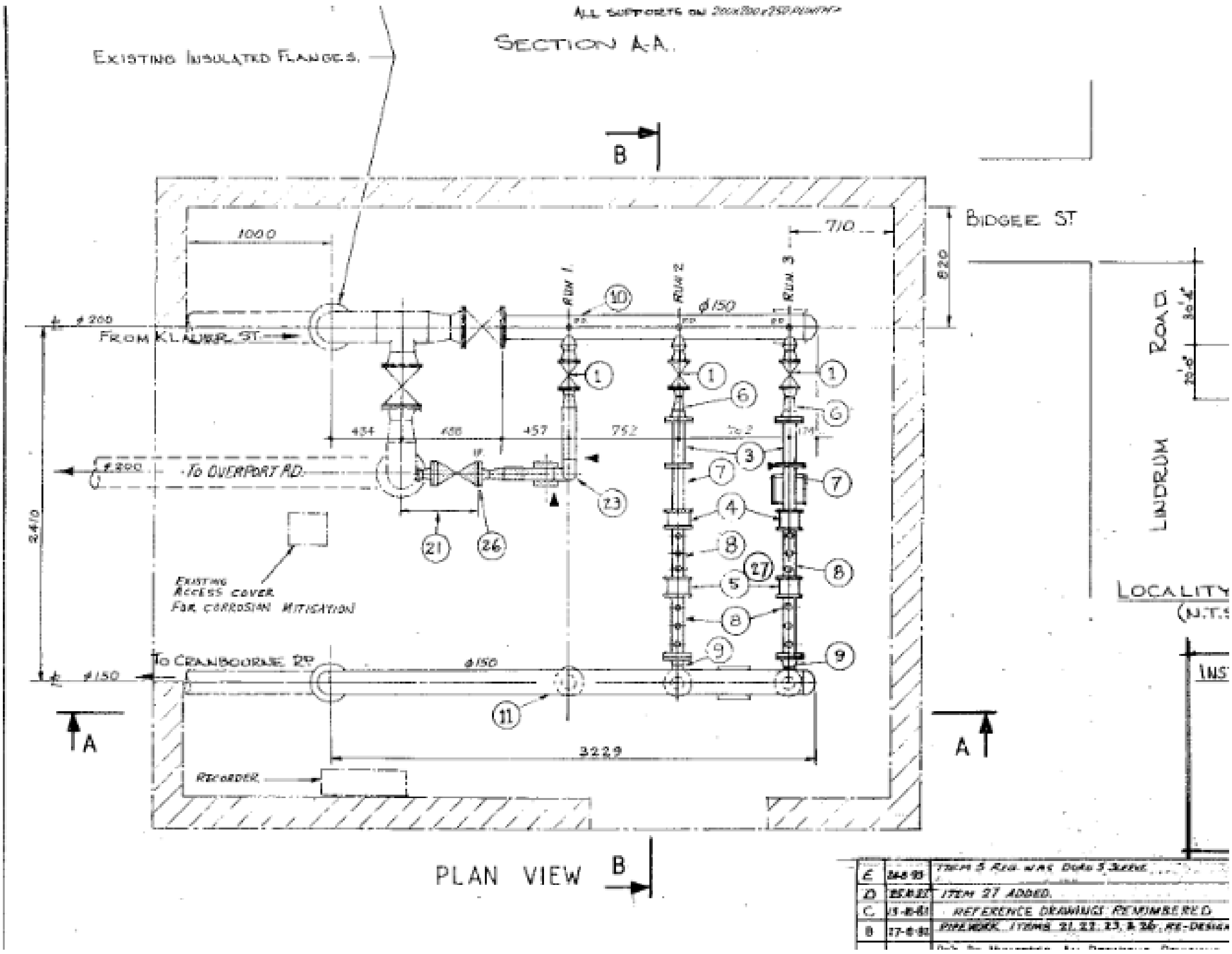
Project Estimate:

[redacted]

P4-0013, Lindrum Rd Frankston, 3199



Site Layout: P4-0013



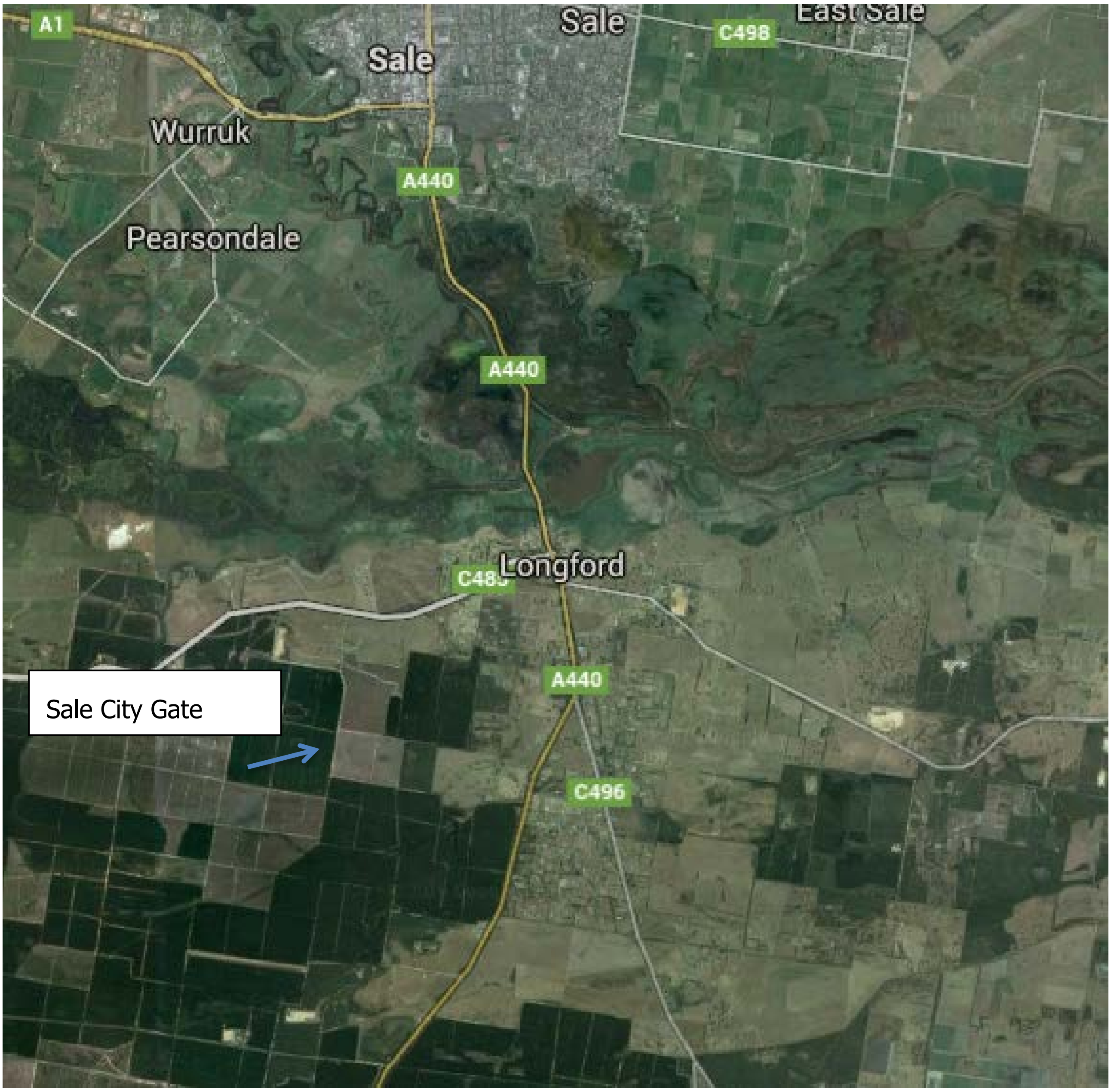
Project Scope:

- Design and Planning – detailed designs for new regulator kiosk which will meet network gas capacity requirements and environment noise restrictions and obtaining consent to construct and operate from Energy Safe Victoria (ESV).
- Procurement – through tendering process, procurement of the regulation kiosk.
- Modifying existing kiosk to accommodate new pipework
- Installation of new pipework, valves, regulators by external contractor.
- Commissioning of the facility by operations personnel.
- Decommissioning of existing pipework and removal
- Facility drawing – update all drawings to reflect changes
- Asset management system – update Maximo asset management system with changes and ensure preventative maintenance program meets AGN requirements

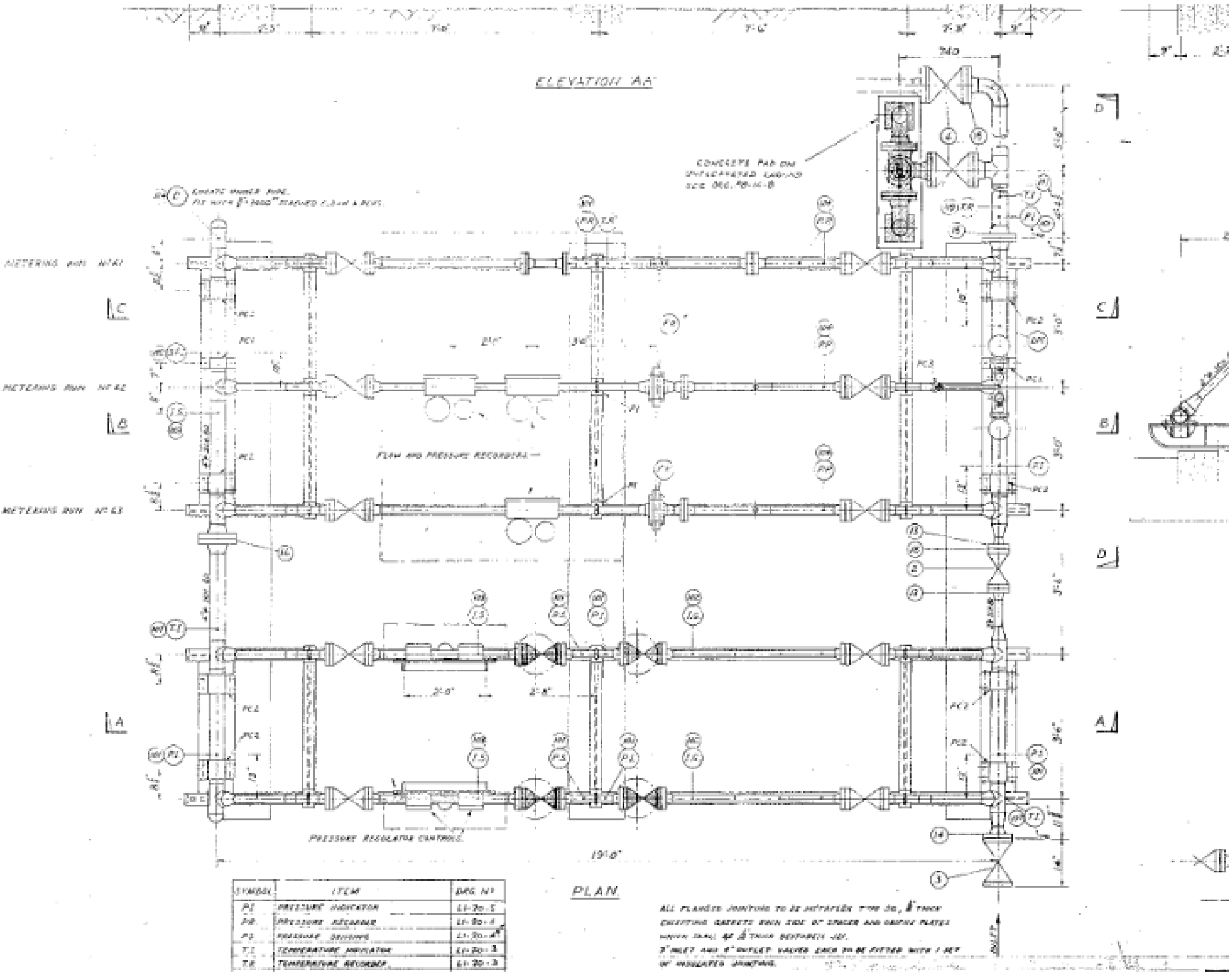
Project Estimate:

[redacted]

P8-0014, Sale City Gate,



Site Layout: P8-0014



Project Scope:

- Design and Planning – detailed designs for new regulator kiosk which will meet network gas capacity requirements and environment noise restrictions and obtaining consent to construct and operate from Energy Safe Victoria (ESV).
- Procurement – through tendering process, procurement of the regulation kiosk.
- Modifying existing kiosk to accommodate new pipework of existing skid
- Installation of new pipework, valves, regulators by external contractor.
- Commissioning of the facility by operations personnel.
- Decommissioning of existing pipework and removal
- Facility drawing – update all drawings to reflect changes
- Asset management system – update Maximo asset management system with changes and ensure preventative maintenance program meets AGN requirements

Project Estimate:

[redacted]

Business Case – Capex V18

H85 Echuca

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	Keith Lenghaus, *Asset Planning Manager*
Approved By	Andrew Foley, *General Manager Vic Networks*

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	The Echuca high pressure (HP) network (H85) supplies gas to the townships of Echuca in Victoria and Moama in New South Wales. Continuing residential growth within these areas is expected to reduce pressures within the network to below the recommended minimum considered essential to maintain a safe and reliable supply of gas to consumers. Operating below the recommended minimum pressure could result in the loss of several hundred consumers. In circumstances where there is a momentary loss of supply there is a risk that this could lead to a gas in building incident causing major damage and or life threatening injuries. The risk associated with gas outage has been assessed as 'moderate' Augmentation of the network is required to meet AGN's obligations to: • Maintain network pressures above the distribution supply point minimum specified in the Victorian Distribution System Code (Code). Failure to do so would be considered a breach of AGN's license condition. • Maintain and improve the safety of services to consumers – Failure to do so could result in serious injury or damage to property • Maintain a reliable supply to consumers – Failure to do so would incur Guaranteed Service Level (GSL) payments and have potential, in the long term, to harm the reputation of natural gas as a reliable energy source promoting consumers to switch to alternatives. • Connect customers that are within minor or infill areas as required by the Code – Failure to do so would be considered a breach of AGN's license condition Viewed in this way augmentation of the Echuca network is required to: • comply with the regulatory obligations set out in the Code; and • maintain and improve the safety and reliability of services.
Options Considered	The following options have been considered to address the growth in the Echuca HP network: • Option 1: Allow ongoing growth to decrement capacity to the extent that supply loss becomes a more regular event. • Option 2: Control the amount of additional load of the network by either limiting connections or implement demand management (turn off during peak periods)

Proposed Solution	• Option 3: Augment the network by duplicating a section (1,000 metres) of the polyethylene (PE) trunk mains supplying Echuca and providing an 'interconnection' (250 metres) of the network in Moama • Option 4: Defer augmentation into the following regulatory period Options 1, 2, and 4 are not considered feasible given the regulatory obligations to maintain a safe and reliable supply of gas to consumers. Option 3 is the only feasible solution which maintains a safe and reliable gas supply to existing consumers while supporting new connections to the existing network.
	Option 3 has been selected because it is the most effective way to comply with regulatory obligations set out in the Code to maintain a safe and reliable supply of gas to customers. This option reduces the risk from 'medium' to 'low' consistent with obligations under Australian Standard AS/NZ 4645.
Estimated Cost	The forecast capital expenditure (capex) over the next AA period for Option 3 is \$491.3 (\$000, 2016).
Consistency with the National Gas Rules (NGR)	The augmentation complies with the new capital expenditure (capex) criteria in rule 79 of the National Gas Rules (NGR) because: • it is necessary to maintain and improve the safety of services or maintain the integrity of services or comply with a regulatory obligation (rules 79(2)(c)(i) (ii) and (iii)); 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	AGN has undertaken a comprehensive stakeholder engagement program to better understand the needs and values of our stakeholders and customers. During this engagement, customers told us that they value current standards of reliability and are supportive of initiatives that maintain their reliability and improve the safety of the network. Implementation of this initiative will allow AGN to maintain the safety of the network while continuing to provide a highly reliable supply of natural gas to our customers. More information detailing the results of AGN's stakeholder engagement program is provided in Chapter 5 of the Access Arrangement Information document.

1.3. Background

1.3.1. General

The regional Echuca high pressure (HP) network (H85) straddles the Victorian – New South Wales border providing gas to the townships of Echuca in Victoria and Moama in New South Wales.

This network supplies gas to approximately 7,000 residential customers and eight major industrial and commercial customers.

This network is supplied from a city gate station four kilometres south of the Echuca township's. Gas from the gate station is distributed north to Echuca, then across the Murray River and into Moama, with the furthest extent of the network approximately 15 kilometres from the point of delivery. An overview map of the network is provided in Appendix A.

Capacity modelling[1] has confirmed that ongoing residential growth in the area will reduce network pressures to below the minimum required to sustain a safe and reliable supply of gas. Modelling

[1] H85 2015 Network Capacity Review

has highlighted the need to duplicate the existing Echuca trunk main and provide an interconnection within the gas network in Moama.

The remainder of this section details our obligations and explains why there is a need to deliver augmentation of the Echuca network over the next AA period.

1.3.2. Regulatory Obligations and the Echuca Network

1.3.2.1. Obligation to Maintain Supply Pressure

Under the Code[2], AGN has a regulatory obligation to use all reasonable endeavours to:

> *"…ensure the minimum pressure is maintained at the distribution supply point.[3]"*

This requirement covers both distribution and transmission pipelines. In the Echuca network, the minimum Distribution System Pressure required by the Code is 140 kPa.[4] Over the next AA period fringe pressures in Echuca are expected to fall below the recommended design minimum commencing from the 2021 winter (refer to Table 1.4 for details).

1.3.2.2. Obligation to Connect

In addition to having an obligation to maintain supply pressures, AGN also has an obligation under the Code to connect customers that are within the minor infill extension areas.[5] Specifically, clause 3.1(c) of the Code states that:

> *"A Distributor must connect the gas installation of a customer that resides within the minor or infill extension area on fair and reasonable terms and conditions"*

The growth forecast discussed in the Section 1.4.2 is based on projected dwelling construction within areas that would be considered minor or infill extension under the Code.

1.3.2.3. Guaranteed Service Level

In the event that interruptions to supply occur, depending on the circumstances and duration of interruption AGN may be required to make a GSL[6] payment to each affected customer. GSL payment depends on the duration of customer outage with payments of up to $300 applicable for extended outages.

[2] The Code has been developed by the Victorian Essential Services Commission and applies to all distributors that hold a distribution licence. The Code sets out the minimum standards for the operation and use of the distribution system, which include, amongst other things, minimum standards for connections and augmentations. As stated in the notes to section 3 of the Code, clause 4 of AGN's Gas Distribution Licence requires compliance with this Code.

[3] Schedule 1 Part A of the Code.

[4] This obligation is set out in Schedule 1 of the Code.

[5] The term 'minor and infill extension area' is defined in clause 2.1(f) of the Code as an area that is up to 1 km radially from the nearest part of the distribution system main.

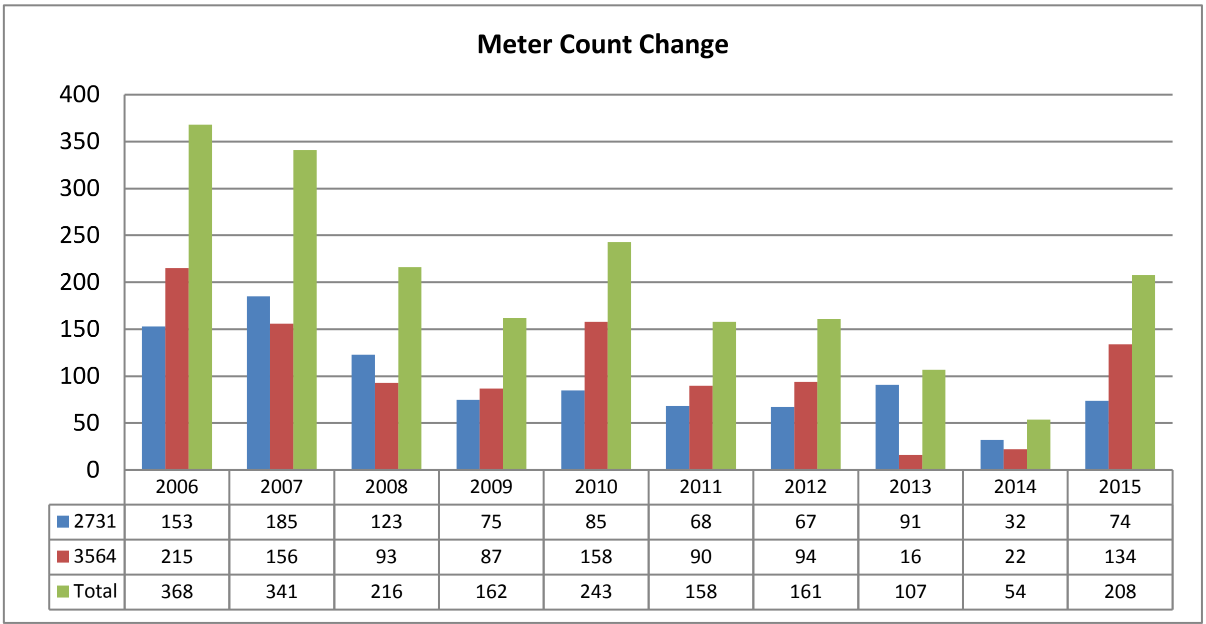
[6] The GSL payment is intended to ensure that customers are compensated if an energy distribution company does not meet certain minimum performance standards. The amount payable and the conditions under which a GSL payment is triggered are set out in Part E of the Code. For supply interruptions, repeated or lengthy interruptions would incur a GSL of between $150 and $300 per affected customer. Refer ESC website for a copy of the Code: http://www.esc.vic.gov.au/document/energy/26123-gas-distribution-system-code-2/

1.4. Key Drivers and Assumptions

1.4.1. Historic Growth

Figure 1.1 summarises the historic growth in the Echuca and Moama areas (postcodes 3564 and 2731) served by the Echuca HP network.

Figure 1.1: Meter Connections Historic Growth



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
2731	153	185	123	75	85	68	67	91	32	74
3564	215	156	93	87	158	90	94	16	22	134
Total	368	341	216	162	243	158	161	107	54	208

The five year average net connections from 2011 to 2015 are about 140 per year. The 10 year average is around the 200 connections per year.

1.4.2. Future Demand

Table 1.3 summarises the criteria and assumptions used to establish demand in the Echuca HP network over the next Access Arrangement (AA) period.

Table 1.3: Growth Assumptions

Criteria/Assumption	Basis
Average annual growth in net new tariff V customer will continue at an average of about 140 connections per year	This is based on a five year average historic connection rate.
No additional Tariff D load	Tariff D Loads arrive unpredictably, and growth in D load has not been allowed for in this analysis. Tariff D load growth will be addressed on an as needed basis, with cost of connection assessed at the time of enquiry.
Average demand per Tariff V	The calculated ratio of tariff V design load to tariff V meter connection numbers in the Echuca network. It should be noted that this can vary from location to location with

customer of 0.76 m^3/hour	actual averages of up to 1.0 m3/hr in some parts of the network.

1.4.3. Customer Impact

Continued growth in Echuca and Moama is expected to reduce network pressures at various locations within the Echuca network over the next AA period. Table 1.4 summarises the impact on network pressures at various fringe point locations.

Table 1.4: Echuca Network Minimum Pressure (kPa)

Location	2016	2017	2018	2019	2020	2021	2022
Echuca minimum pressure	182	172	165	153	140	**128**	**113**
Customers < 140 kPa	0	0	0	0	0	430	539
Number of customers nil gas	0	0	0	0	0	0	0

The analysis shows that network pressures are expected to drop below the required minimum from about 2021.

The final two rows of this table set out:

- the number of customers that could be affected by the reduction in pressure below the 140 kPa Code requirement and could therefore be at risk of a transient gas outage[7]; and
- the number of customers that are at risk of receiving no gas at all if network pressures fall below atmospheric pressure.

It is estimated that up to 500 customers could be impacted by poor system pressures by 2022 resulting in:

- transient and unpredictable interruptions to gas supply, occurring at increasing frequency year on year; and
- the potential for an outage to result in release of un-combusted natural gas from a burner that was extinguished during the outage but remained open up to the recovery of gas supply, leading to natural gas accumulation in a confined space followed by fire, explosion or asphyxiation.

Further detail on these risks can be found in Section 1.5

Taking action to address these issues is consistent with the findings of our stakeholder engagement program which found strong support from workshop participants for AGN to undertake key projects like this one to ensure reliability to existing customers is maintained, and which are necessary investments arising from the demands of ongoing customer connection growth.

[7] The term 'transient gas outage' is used in this context to refer to the situation where tariff V gas demand outstrips the network's supply capability for a relatively short period of time. This could occur on a gas day if peak demand is too large and the pressure at the end of the network drops to such a low level that customers in the area of low pressure experience an interruption in supply. Once the peak load starts to fall, the network pressures will start to recover and the supply of gas will return to these customers.

1.4.4. Summary

Continued residential growth in the Echuca and Moama area will require the capacity of the Echuca HP network to be augmented during the next AA period. This will be necessary to:

- maintain minimum gas pressures, as set out in the Gas Distribution Code, necessary for a safe and reliable supply of gas to existing consumers;
- avoid GSL payments and relight costs associated with gas outages; and
- meet AGN's obligation to supply 'infill' growth across the Echuca and Moama townships.

1.5. Risk Assessment

A risk assessment of the following scenarios has been carried out in accordance with the APA Risk Policy and Risk Matrix.

Scenario 1. Organic Tariff V growth has reduced the Echuca HP network pressure to below the recommended minimum during the winter peak demand period resulting in the loss of supply to more than 100 customers. This is considered an 'occasional' event as per the APA Risk Policy.

Scenario 2. Network pressure at the extremity of the HP network drops below the recommended minimum resulting in a momentary loss of supply to a number of consumers. This in turn causes a flame out on an appliance (cook top) and the subsequent return of supply results in a gas in building (GIB) incident that remains unnoticed by the occupant resulting in a fire or explosion. This is considered to be a 'rare' event as per the APA Risk Policy

The table below summarises the risks associated with these three scenarios. A detailed breakdown of the risk assessment has been provided in Appendix B.

Table 1.5: Risk Rating

Risk Area	Untreated Risk Scenario 1	Untreated Risk Scenario 2
Health and Safety	N/A	Moderate
Environment	N/A	Negligible
Operational	Moderate	Negligible
Customers	Low	Negligible
Reputation	Low	Moderate
Compliance	Moderate	Moderate
Financial	Low	Moderate
Untreated Risk Rating	**Moderate**	**Moderate**

The risk associated with the loss of supply has been assessed as 'moderate'.

While there is the potential for an outage to result in the release of un-combusted natural gas from a burner, leading to a fire, explosion the risk is also considered 'moderate' as the likelihood is rare.

AGN has an obligation under its license conditions to assess its asset risks and reduce any 'high' or 'moderate' risks to 'low' or 'negligible' and if not 'as low as reasonably practicable'.

1.6. Options Considered

AGN has considered the following options to address the network capacity issues outlined above.

- Option 1: Allow ongoing growth to decrement the Echuca network capacity to the extent that supply loss becomes a more regular event.
- Option 2: Control the amount of additional load on the network by either limiting connections or implement demand management (turn off during peak periods).
- Option 3: Augment the network by duplicating a section of trunk mains supplying Echuca and 'interconnection' of the network within Moama
- Option 4: Defer augmentation into the following regulatory period

Further detail on these options is provided below.

1.6.1. Option 1 – Accept increasing risk of supply loss

Under this option, AGN will continue to accept network connections (as it is required to do under the Code) but do nothing to address the effect on the network design minimum pressures.

1.6.1.1. Cost/Benefit Analysis

The benefit of this option is that it does not give rise to any upfront capital costs. This option would, however, result in AGN contravening its regulatory obligation to use all reasonable endeavours to

> *"ensure the minimum pressure is maintained at the distribution supply point"*

and as a result the network design minimum pressures will be breached by an increasing amount and frequency each year, impacting an increasing number of customers in the Echuca network.

This option does not address:

- *Reduced reliability and security of supply* – Connected customers towards the fringe of the network will not have 'un-fettered' use of the gas supply that they have paid for. Not all customers will be impacted equally, creating an inequitable supply privilege gradient where customers closer to the gate get a better level of service at the expense of customers at the network fringe. This is inconsistent with the intent of the gas regulatory framework (including the Access Arrangement framework), which is designed to ensure that all customers are treated equitably and are provided with access on a non-discriminatory basis.
- *Potential safety issues with the network* – A gas network that is not operating correctly or predictably is an unsafe network. A transient loss of gas gives rise to the risk of the release of un-combusted gas, as operating gas appliances do not necessarily respond to loss of gas by automatically turning off. As free gas is released there is the potential for it to collect in a confined space and eventually catch fire or explode, which poses a risk to human health and

safety and property. Doing nothing to address the risk of gas intrusion is inconsistent with Australian Standard AS4645 (Gas Distribution Network Management), which requires that this must be managed to 'low' or 'negligible' and if not to 'as low as reasonably practicable'.

- *Increased Opex as result of GSL payments and relights* - The increased risk of an outage under this option also increases the likelihood that AGN will have to make GSL payments (lengthy interruptions incur a charge of $300 per affected property) and incur costs relighting customers, with the costs of the order of $40 per relight.

Given the risks posed by this option and the fact that it would result in AGN failing to comply with its regulatory and code obligations this option is not considered or prudent or viable option.

1.6.2. Option 2 – Control/Limit Additional Load

Under this option AGN would maintain the current network configuration without augmenting the network and limit network connections and or reduce consumption during peak periods. This would be aimed at ensuring pressures at the extremity of the Echuca HP network are maintained above the required minimum ensuring that a safe and reliable supply can be maintained.

1.6.2.1. Cost/Benefit Analysis

Like Option 1, the benefit of this option is that it does not give rise to any upfront capital costs. However, this option is not considered prudent or viable for the following reasons:

- Limiting future connections would contravene AGN's regulatory obligation under the Code to connect customers that are with the minor or infill extension areas
- Existing contracts have not been structured to allow for 'turndown' of supply during peak periods. From a practical point of view it would be impossible to 'predict' capacity shortfalls in the network with sufficient lead time to allow major consumers to reduce their consumption by shifting to alternative energy sources or curtailing operations.

No further consideration has therefore been given to this option.

1.6.3. Option 3 – Staged Network Augmentation

The third option that AGN has considered is to augment the Echuca network by duplicating a section of the HP trunk main feeding Echuca and providing an interconnection within the network in Moama (refer to Appendix A Figure A:1. for location details). The scope and timing of this augmentation is summarized in Table 1.6 below.

Table 1.6: Staged Network Augmentation

Year	Infrastructure	Cost Estimate ($,000 2016)
Mains Infrastructure		
2020	Moama: 250 metres x DN63 PE main from HP trunk main in Cobb Highway connecting to the DN50 main in Shetland Drive	48
2021	Echuca: 1000 metre x DN180 PE main duplicating the trunk main along McKenzie Road.	443.3
	Total Capital Expenditure	**491.3**

1.6.3.1. Cost/Benefit Analysis

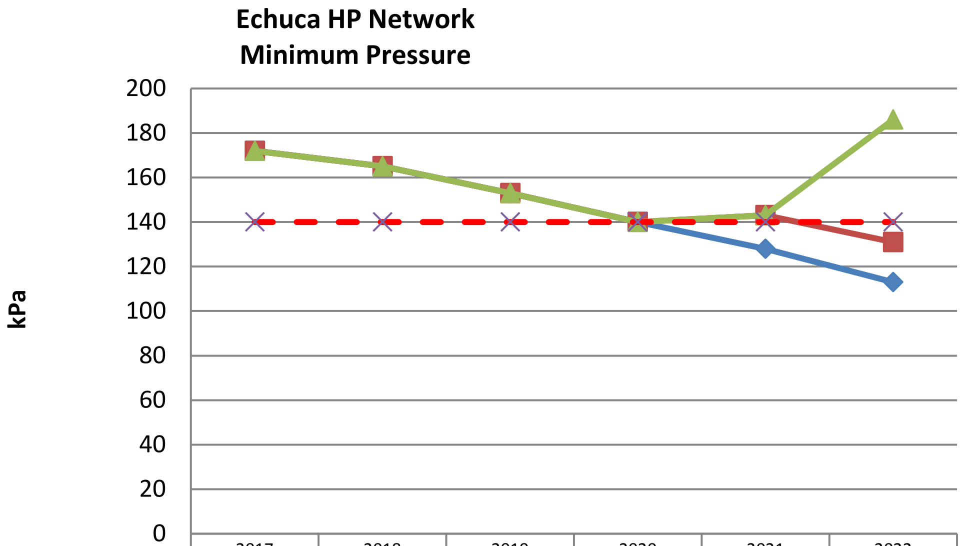
The capital cost of this Option 3 is $ 491.3 ($'000, 2016). Refer to Appendix C for a detailed cost breakdown.

The benefit of this option is that it reduces risk of gas outage from 'moderate' to 'low' (refer to Appendix B), and in doing so:

- ensures compliance with AGN's regulatory obligations under the Code by:
  - ensuring that minimum network pressures are maintained at distribution supply points and, in so doing, maintain the integrity of services; and
  - allowing new connections to occur (as required by the Code), without risk to gas supply at the network fringe;
- maintains the safety of services by reducing the risk of gas intrusion and the associated risks to human health and safety to as low as reasonably practicable, consistent with Australian Standard AS4645; and
- reduces the likelihood that AGN will have to make GSL payments and incur costs in relighting customers if there is an outage.

Figure 1.2 summarises the expected minimum pressure at fringe point locations within the Echuca HP network given the proposed augmentation.

Figure 1.2: Network Pressure – Post Augmentation



	2017	2018	2019	2020	2021	2022
Without Augmentation	172	165	153	140	128	113
Cobb Hwy Augmentation	172	165	153	140	143	131
Cobb Hwy & McKenzie Augmentation	172	165	153	140	143	186
Required Minimum	140	140	140	140	140	140

The proposed duplication and interconnection will support forecast load growth at least through to the end of 2022.

1.6.4. Option 4 – Defer Augmentation

Deferring the augmentation into the following regulatory period (2023 – 2027) has been considered. This would require the acceptance of a 'moderate' risk of gas outage for several years. AGN would be non-compliant with its obligations to maintain a safe and reliable supply to consumers for the period of delay.

The cost of this option would effectively see Option 3 escalated to the future year of execution.

There would be a small cost saving (arising from the time cost of money) to customers from deferring the work. This cost saving is considered to be immaterial compared to being non-compliant, while posing an increased safety and supply risk and being inconsistent with the prudent and efficient operation of the network.

Given AGN's obligations, deferral was not considered a prudent or efficient option.

1.7. Summary of Cost/Benefit Analysis

Table 1.7 below provides a summary of costs, risks and benefits associated with the four options.

Table 1.7: Summary of Cost/Benefit Analysis

Option	Benefits	Costs/Risks
Option 1	Avoids up front capital expenditure.	No capital costs GSL payments of up to $300 per customer plus $40 per customer for relight in event of a gas outage. AGN would fail to comply with its regulatory obligations under the Code to use all reasonable endeavours to ensure safe and reliable supply of gas to consumers. Residual risk is 'moderate' Not a prudent option
Option 2	Avoids up front capital expenditure.	No capital costs Impractical to implement - contracts do not allow for demand management. AGN would fail to comply with its obligation under the Code to connect customers. Not a prudent option
Option 3	Ensures AGN complies with the pressure and connection provisions in the Code. Reduces the risk of gas outages and the associated risks to human health and safety to as low as reasonably practicable. Maintains the reliability of supply to existing consumers.	Capital costs $491.3 ($'000 2016) for duplication of the trunk main to Echuca and interconnecting the network in Moama. This the recommended option based on reducing risk from 'moderate' to 'low' at the lowest cost.
Option 4	Deferral creates time value of money savings	No capital costs in the next regulatory period AGN would fail to comply with its regulatory obligations under the Code to use all reasonable

Option	Benefits	Costs/Risks
		endeavours to ensure safe and reliable supply of gas to consumers. Residual Risk is 'high' Not considered a prudent option

1.8. Proposed Solution

1.8.1. What is the proposed solution?

The proposed solution is Option 3, which will involve duplicating a section of the trunk main feeding the Echuca and interconnection of the network in Moama.

The scope, timing and costs are summarised in Section 1.6.3.

1.8.2. Why are we proposing this solution?

Option 3 has been selected because:

- The project is required to comply with regulatory obligations under the Code to maintain a safe and reliable supply of gas to customers.
- It is the most cost effective solution – The proposed augmentation represents the minimum amount of augmentation necessary to sustain growth over the next regulatory period. Depending on growth further 'staged' augmentation will be necessary in the following period.
- It is a low risk, technically simple and proven solution. Laying pipe in the ground provides a known capacity improvement for an expenditure amount that can be relatively accurately quantified. The risk of delivery is minimal, on either a time or budget basis.

1.8.3. Stakeholder Engagement

Overall, our customers told us that they value current standards of reliability and are supportive of initiatives that maintain their reliability and improve the safety of the network with the majority of participants prepared to pay to support the maintenance of the existing level of reliability of the network, with the understanding that upgrades to meet population growth are necessary investments for the supply of gas for Victorian residents into the future.

Projects that support reliability received support from 86% of workshop participants, behind only awareness of AGN assets, ongoing mains replacement program and bushfire preparedness when ranked in order of importance.

Figure 1.3: Stakeholder Engagement Results

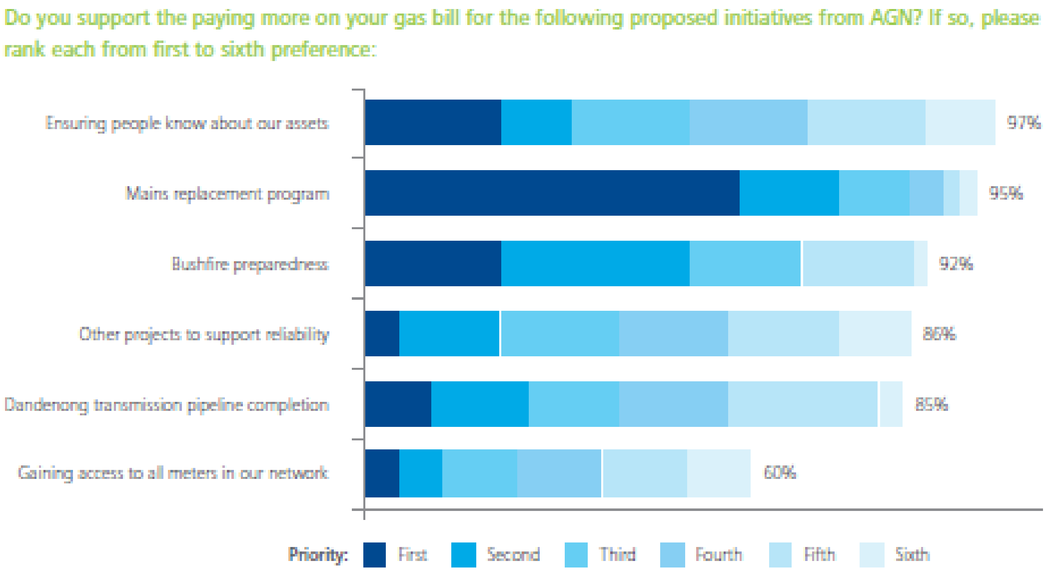


Figure 4: Total workshop support of AGN's proposed initiatives, broken down by preference rank

1.8.4. Forecast Cost Breakdown

Table 1.8 below provides a summary of the capex that is forecast to be incurred in the next AA period under Option 3, which has been estimated on the basis of the following assumptions:

- *Materials* – Where possible, the cost of the materials required is based on the price achieved for comparable works completed elsewhere in the network. Where a suitable cost estimate from outcomes is unavailable, the material cost is estimated from recent quotes received for other similar works and previous cost experience.
- *Labour* – where possible the labour costs have been based on the unit rate achieved as the result of competitive tender between external contractors. This is assumed to reflect the best efficient delivery cost achievable. For specialist services, the cost estimate is derived from the cost of basic due diligence for similar projects.
- *Project Timing* – projects have been sequenced to ensure manageable project delivery targets while avoiding breaching minimum pressures under design conditions. Where design condition assessment (Table 1.7) shows pressures below the Code minimum network management will ensure that supply is maintained.

A detailed cost breakdown can be found in Appendix C.

Table 1.6: Capex Split ($000, 2016)

	2018	2019	2020	2021	2022	Total
Land	-	-	-	-	-	-
Materials	-	-	1.5	63	-	64.5
Labour	-	-	46.4	380.4	-	426.8
Total	**-**	**-**	**47.9**	**443.4**	**-**	**491.3**

1.8.5. Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the National Gas Rules, AGN considers that the capital expenditure is:

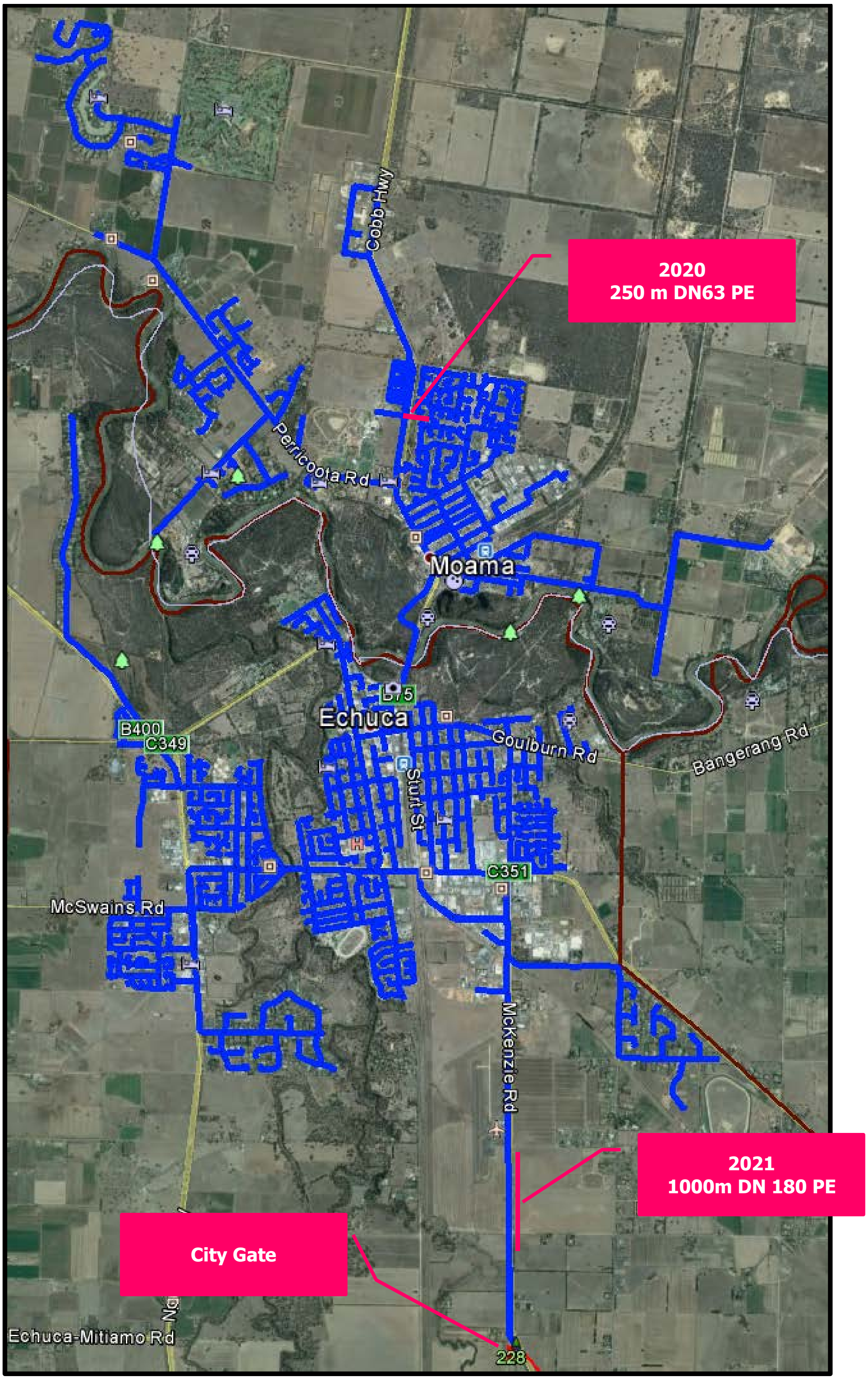
- *Prudent*: The expenditure is necessary to maintain and improve the safety and integrity of services, and to comply with regulatory obligations. It is also of a nature that a prudent service provider would incur.
- *Efficient*: The cost estimates for this project are based on actual costs for similar works that were awarded via competitive tender. The manner in which AGN intends to carry out the work (i.e. field work to be carried out by an external contractor that has demonstrated specific expertise in completing the installation of the assets in a safe and cost effective manner and that will be selected through a competitive tender) can also be considered efficient.
- *Consistent with good industry practice*: Complying with the obligations set out in the Code by carrying out the proposed reinforcement is consistent with accepted and good industry practice. So too is reducing the risk to human health and safety posed by gas outages to as low as reasonably practicable in a manner that balances cost and risk as required by AS 4645 (Gas Distribution Network Management).
- *Achieve the lowest sustainable cost of providing the service*: The scale of augmentation is designed to match the network requirements, balancing the objectives of minimising community disruption during construction and the need to revisit augmentation within a short time without overinvesting in the network. Proactively addressing emerging gas supply issues will avoid multiple reactive measures, thereby ensuring the lowest long-term sustainable cost for customers. Continuing to expand the Network ensures that operating costs are spread over an increasing number of customers, helping to drive down the average cost per customer.

The capex can therefore be considered consistent with rule 79(1)(a) of the NGR. The proposed capital expenditure is also consistent with 79(1)(b), because it is necessary to:

- *maintain and improve the safety of services (79(2)(c)(i))* – if more connections to the network occur without corresponding augmentation of the network, then the risk of transient gas outages and the associated risk to human health and safety will increase;
- *maintain the integrity of services (79(2)(c)(ii))* – if the minimum pressure of the network is not maintained through augmentation of the network then the integrity of services will be adversely affected; and
- *comply with a regulatory obligation (79(2)(c)(iii))* – AGN is required by the Code to maintain minimum pressures and to continue to connect new customers located in 'minor infill' areas of the Echuca network.

Appendix A Network Overview

Figure A.1: Echuca Network Map



Appendix B Risk Assessment

Table B.1: Untreated Risk

		Health & Safety	Environment	Operations	Customer	Reputation	Compliance	Finance
Scenario 1 – Supply loss 100 to 1,000 customers from inadequate system pressure	Likelihood	*N/A*	*N/A*	*Occasional*	*Occasional*	*Occasional*	*Occasional*	*Occasional*
	Consequence	*N/A*	*N/A*	*Medium*	*Minor*	*Minor*	*Medium*	*Insignificant*
	Risk Level	*N/A*	*N/A*	*Moderate*	*Low*	*Low*	*Moderate*	*Low*
Scenario 2 – GIB incident from transient supply loss	Likelihood	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*
	Consequence	*Major*	*Minor*	*Minor*	*Minor*	*Major*	*Major*	*Medium*
	Risk Level	*Moderate*	*Negligible*	*Negligible*	*Negligible*	*Moderate*	*Moderate*	*Moderate*

Table B.2: Treated Residual Risk

		Health & Safety	Environment	Operations	Customer	Reputation	Compliance	Finance
Scenario 1 – Supply loss 1,000 to 10,000 customers from inadequate system pressure	Likelihood	*N/A*	*N/A*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*
	Consequence	*N/A*	*N/A*	*Medium*	*Minor*	*Minor*	*Medium*	*Insignificant*
	Risk Level	*N/A*	*N/A*	*Low*	*Negligible*	*Negligible*	*Low*	*Negligible*

Appendix C Detailed Cost Estimate

Table C.1: Detailed Cost Estimate

Job Description : Augmentation - 1000m x 180PE along Mckenzie Rd Echuca and 250m x 63PE Cobb Hwy to Shetland Drv Moama

DESCRIPTION	Units	UOM	$/unit	ITEM COST	LINE COST	TOTAL COST
NUMBER OF SITES						
By Internal Labour	0	ea				
By Contractor	2	ea				
TOTAL SITES	2	ea				
MATERIALS						
McKenzie Rd	1000	ea	$ 62.95	$62,950	$62,950	
Shetland Drv	250	ea	$ 6.19	$1,548	$1,548	
	0	ea	$ -	$0		
	0	ea	$ -	$0		
	0	ea	$ -	$0		
					$64,498	
				Total Material costs		$64,498
LABOUR						
Labour						
M & S Labour (contractor)						
McKenzie Rd Echuca						
McKenzie Rd - Excavation, joining PE 180mm, steel 200mm, laying pipe, backfill, quarry products, welder for WT, TDW tapping x 2,	1000	m	165.34	$165,340		
Welder for valves & fittings (Exc WT)	132	Hr	24	$3,168		
Surveyor	1	Ea	5000	$5,000		
					$173,508	
Shetland Drv Moama						
Shetland Drv - Excavation, joining PE 63mm, laying pipe, backfill, quarry products, tie-ins x 2, cutting of hard surfaces	250	m	52.8	$13,200		
					$13,200	
				Total Labour Costs		$186,708
MISCELLANEOUS						
McKenzie Rd Echuca						
Environmental	25000	1	25000	$25,000		
Site Compound	15000	1	15000	$15,000		
HDD	250	85	21250	$21,250		
Traffic Management	2132.7	per day	14	$29,858		
Uncosted items	99768.55	1	1	$99,769		
					$190,876	
Shetland Drv Moama						
Traffic Management	2470.85	per day	5	$12,354		
Reinstatements	1015.2	1	1015.2	$1,015		
HDD	50	45	2250	$2,250		
Uncosted items	13605.68	1	1	$13,606		
					$29,225	
Project Management, APA Supervision, Administration	1	off	$20,000	$20,000		
					$20,000	
				Total Misc Costs		$240,101
TOTAL BUDGET COST - 2 Sites -						$491,307

Business Case – Capex V23

Dandenong Crib Point Pipeline Augmentation

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	Keith Lenghaus, *Asset Planning Manager*
Approved By	Andrew Foley, *General Manager Victorian Networks*

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	The Dandenong to Crib Point (DCP) transmission pressure (TP) pipeline is the primary supply to high pressure networks in the Mornington Peninsula supplying gas to over 100,000 consumers Continuing growth in the area over the next regulatory period is expected to reduce pipeline pressure below the recommended minimum considered essential to maintain a safe and reliable supply of gas to customers. Operating below the recommended minimum pressure could result in the loss of several thousand customers. In circumstances where there is a momentary loss of supply there is a risk that this could lead to a gas in building incident causing major damage and or life threatening injuries to occupants. In addition, a single point of failure of section of the pipeline could, in certain circumstances, result in a loss of supply to over 1000,000 customers. Augmentation of the network is required to meet AGN's obligations to: • Maintain network pressures above the distribution supply point minimum specified in the Victorian Distribution System Code (Code). Failure to do so would be considered a breach of AGN's license condition. • Maintain and improve the safety of services to consumers – Failure to do so could result in serious injury or damage to property • Maintain a reliable supply to consumers – Failure to do so would incur Guaranteed Service Level (GSL) payments and have potential, in the long term, to harm the reliable reputation of natural gas promoting customers to switch to alternative energy sources. • Connect customers that are within minor or infill areas as required by the Code – Failure to do so would be considered a breach of AGN's license condition Viewed in this way augmentation of the DCP pipeline is required to: • comply with the regulatory obligations set out in the Code; and • maintain and improve the safety and reliability of services.
Options Considered	The following options have been considered: • Option 1: Allow ongoing growth to decrement capacity to the extent that supply loss becomes a more regular event. • Option 2: Control the amount of additional load on the network by either limiting connections or implement demand management (turn off during peak periods). • Option 3: Complete the duplication of the DCP pipeline by constructing a 4 kilometre TP steel pipeline connecting previously duplicated sections to the Dandenong City

	Gate (DCG). • Option 4: Construct a 2.5 kilometre TP steel pipeline and a new city gate station (alternative supply point to the DCG). • Option 5: Construct a 3.5 kilometre TP steel pipeline (on a different alignment to Option 4) and a new city gate city gate station. • Option 6: Defer augmentation into the following regulatory period. Options 1, 2, and 6 are not considered prudent given AGN's regulatory obligations to maintain a safe and reliable supply of gas to consumers. The main difference between options 3, 4 and 5 are the risks and costs associated with various alignments and the capacity that they provide. Options 4 and 5 include new (additional) custody transfer and pressure regulating facilities.
Proposed Solution	Option 3 has been selected because it is the lowest cost long term solution that addresses both capacity and security of supply issues of the DCP pipeline. This option reduces supply loss risk from 'high' to 'moderate', which is' as low as reasonably practicable'. The reduction of risk is an obligation under Australian Standard AS/NZS 2885 and AS/NZS 4645.
Estimated Cost	The forecast capital expenditure (capex) over the next AA period for Option 3 is $13,800 ($'000 2016).
Consistency with the National Gas Rules (NGR)	The augmentation complies with the new capital expenditure criteria in rule 79 of the National Gas Rules (NGR) because: • it is necessary to maintain and improve the safety of services, maintain the integrity of services, comply with a regulatory obligation and meet existing levels of demand (rules 79(2)(c)(i)-(iv)); 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	AGN has undertaken a comprehensive stakeholder engagement program to better understand the needs and values of our stakeholders and customers. During this engagement, customers told us that they value current standards of reliability and are supportive of initiatives that maintain their reliability and improve the safety of the network. More information detailing the results of our stakeholder engagement program is provided in Chapter 5 of the Access Arrangement Information document.

1.3. Background

1.3.1. General

The Dandenong to Crib Point (DCP) pipeline was constructed in 1966 carrying gas from the Dandenong City Gate (DCG) to the southern extremity of the Mornington Peninsula. It is a 38 kilometre long DN300 coal tar enamel pipeline with a maximum allowable operating pressure (MAOP) of 2,760 kPa. Refer to Appendix A for an overview of the network configuration.

The DCP supplies gas to the high pressure network in the Mornington Peninsula via a number of transmission to high pressure regulators (TP/HP). The TP/HP regulators have been designed based on a minimum up stream pressure (typically 1050 kPa) to maintain a nominal 450 kPa to the downstream HP network. Operating the DCP pipeline below the TP/HP regulator minimum inlet pressure would affect the capacity of regulators to the extent that pressures at the 'fringes' of the downstream HP networks could drop to below the 140 kPa minimum as mandated in the Victorian Distribution System Code[1] (Code). Operating above this minimum is required ensure a safe and reliable delivery of gas can be maintained to customers under peak demand conditions.

Over the last 10 years a strategy of progressively duplicating the DN300 DCP pipeline with a DN450 main has been pursued to address capacity limitations. The 'final' stage of duplication from Abotts Road to the DCG (Option 3 as detailed in this business case) has been deferred pending confirmation that growth in demand will decrement the pressure in the pipeline to the point that safety and reliability of supply is affected.

Capacity modelling of the DCP pipeline, undertaken over the last 12 months, has confirmed that minimum pressures at the southern extremity, in the vicinity of the Dunns Road TP/HP regulator will drop below the required 1,050 kPa during the next Access Period (AP).

The existing DCP DN300 pipeline is about 50 years old with an increasing number of coating defects detected over the last five years. These defects are impacting the integrity and residual life of the pipeline. A business case (Project V 54) has been included for the next AP to undertake a number of measures to assess the condition and integrity of the pipeline. To 'prove' the integrity of the pipeline is suitable for continued service, an in line inspection (ILI) is required. The ILI involves a tool ('intelligent pig') inserted into the pipeline (whilst in service) and driven by gas pressure to traverse the length of the pipeline. As the tool moves along the pipeline it locates defects (corrosion, metal loss, deformation, and cracking) that could be deleterious to integrity of the pipeline measuring their location, nature and magnitude.

An engineering risk assessment of the ILI process identified a potential for loss of supply to over 100,000 consumers[2] should the ILI tool get 'stuck' in a section of the pipeline downstream of the DCG. (Note: This loss of supply could also be triggered if emergency isolation of this section is required in response to a major leak cause by corrosion or 3rd party damage.) Given the risk to supply the ILI inspection has been deferred pending completion of the DCP duplication.

In event of a major incident where supply is lost to over 100,000 consumers, restoration of supply could take several weeks with relight costs of the order of $40 per customer. Consumers in Victoria are also subject to Guaranteed Service Levels (GSL) with AGN liable for payments of up to $300 per consumer where supply is interrupted for extended periods.

Any augmentation solution to address capacity and security of supply will involve extending a transmission pipeline through built up residential areas with a number of risk issues to be resolved. To this end a two to three year lead time is considered prudent to ensure network augmentation is delivered ahead of any expected shortfall in capacity.

The following sections detail AGN's obligations, drivers and assumptions for the delivery of the planned DCP pipeline augmentation.

1 The Code has been developed by the Victorian Essential Services Commission and applies to all distributors that hold a distribution licence. The Code sets out the minimum standards for the operation and use of the distribution system, which include, amongst other things, minimum standards for connections and augmentations. As stated in the notes to section 3 of the Code, clause 4 of AGN's Gas Distribution Licence requires compliance with this Code.

2 This is a high level estimate, and assumes that some customers will remain supplied via the Dandenong to Frankston TP main and the limited number of HP mains that can be supplied from other distribution points.

1.3.2. Regulatory Obligations

1.3.2.1. Obligation to Maintain Supply Pressure

Under the Code, AGN has a regulatory obligation[3] to use all reasonable endeavours to

> *"ensure the minimum pressure is maintained at the distribution supply point[4]."*

This requirement covers both distribution and transmission pipelines.

Network modelling has confirmed that pressures at the southern extremity (Dunns Road, Dromana) of the DCP will fall below the design minimum between 2018 and 2020 (refer to Table 1.4 for details).

1.3.2.2. Obligation to Connect

AGN has an obligation under the Code to connect customers that are within the minor infill extension areas [5]. Specifically, clause 3.1(c) of the Code states that:

> *"A Distributor must connect the gas installation of a customer that resides within the minor or infill extension area on fair and reasonable terms and conditions"*

Growth in the Mornington Peninsula generally extends from and within the existing HP network falling within the minor or infill growth terminology defined in the Code.

1.3.2.3. Guaranteed Service Levels

In the event that interruptions to supply occur, depending on the circumstances and duration of interruption, AGN may be required to make a Guaranteed Service Level (GSL[6]) payment to each affected customer. GSL payment depends on the duration of customer outage with payments of up to $300 applicable for extended outages.

1.4. Key Drivers and Assumptions

1.4.1. Historic Growth

The DCP supply area takes in several networks across the Mornington Peninsula. Figure 1.1 summarises the year on year increase in customer connections (as measured by meter count) across the networks serviced by the DCP pipeline.

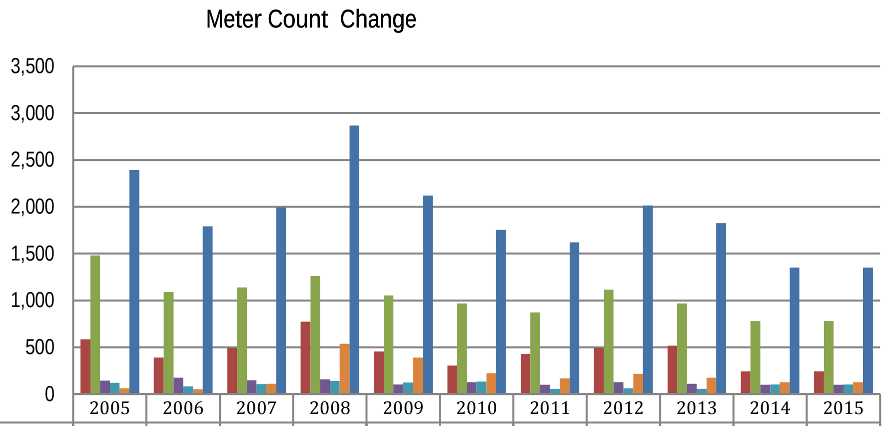
[3] Failure to comply with the Code may result in a range of actions by the Essential Services Commission (ESC) as outlined in its *Compliance Policy Statement for Victorian Energy Businesses*.

[4] Schedule 1 Part A of the Code

[5] The term 'minor and infill extension area' is defined in clause 2.1(f) of the Code as an area that is up to 1 km radially from the nearest part of the distribution system main.

[6] The Guaranteed Service Level (GSL) payment is intended to ensure that customers are compensated if an energy distribution company does not meet certain minimum performance standards. The amount payable and the conditions under which a GSL payment is triggered are set out in Part E of the Code. For supply interruptions, repeated or lengthy interruptions would incur a GSL of between $150 and $300 per affected customer. Refer ESC website for a copy of the Code: http://www.esc.vic.gov.au/document/energy/26123-gas-distribution-system-code-2/

Figure 1.1: Historic Growth



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
H10 Frankston	586	389	493	772	455	303	426	494	518	242	242
H15 Mornington	1,481	1,092	1,137	1,260	1,052	968	872	1,116	967	779	779
H39 Hastings	145	176	148	159	102	126	99	128	110	100	100
H41 Tyabb/ Somerville/ Pearcedale	119	82	105	141	122	132	55	62	54	103	103
H84 Crib Point	61	51	111	536	390	223	169	215	176	128	128
Total	2,392	1,790	1,994	2,868	2,121	1,752	1,621	2,015	1,825	1,351	1,351

The five year average from 2011 to 2015 is about 1,600 net connections while the ten year average is about 1,900.

1.4.2. Future Demand

A number of sources (Victorian Metropolitan Planning Authority 'Precinct Structure Plans' and forecasted dwelling growth publications from the forecast.id website) have been used to conform that growth is likely to continue at rates similar to those observed across the Mornington Peninsula over the last five years.

For modelling purposes two scenarios have been considered:

Scenario 1 - 1,100 new connections per year (derived from external forecast housing developments).

Scenario 2 - 1,600 new connections per year (5 year historic average)

Table 1.3 below summarises the criteria and assumptions used to establish demand and capacity of the DCP pipeline over the next AA period.

Table 1.1: Network Modelling Criteria/Assumptions

Criteria/Assumption	Basis
Net new Tariff V customer connections between 1,100 and 1,600 per year	This is based on: • Scenario 1 - External forecast residential developments and; • Scenario 2 - 5 year historic average net new connections A 'conservative' penetration rate of 80% has been assumed. Actual penetration rates in the area have been of the order of (note that the a 'final' penetration rates of 99% are expected)
Penetration rate of 85%	The historic ratio of active connections to total delivery supply points within the Mornington Peninsula.
Average Tariff V consumption of 0.8 m3/hr	This is the Mornington Peninsula system wide average. It should be noted that this can vary from location to location with demand per Tariff V consumer of more than 1.0 m3/hr in some areas
No additional Tariff D load	Tariff D Loads are unpredictable in terms of size and location. Tariff D load will be addressed on an as needed basis, with cost of any capacity augmentation assessed at the time of enquiry.
1:20 Tariff V profile (same criteria used for the DTS)	This is the same criteria used by AEMO for the Victorian Declared Transmission System (DTS). The 24 hour tariff V profile has been based on an actual 1:20 network demand observed in 2007. This profile was 'adjusted' using the actual 2015 demand (1:2 event) to provide a better estimate of the actual morning and evening peak usage.
Minimum of 2,680 kPa observed at the DCG	The AEMO contractual minimum is 2,650. Actual pressures have been slightly higher than the contractual minimum. It is assumed that this will be the case going forward.

1.4.3. Customer Impact

The DCP pipeline supplies a gas to a number of TP/HP pressure regulating facilities. A low inlet pressure can cause insufficient gas to pass into the HP network placing supply in that network at risk. The most critical location in the DCP pipeline is at the Dunns Road HP regulator located at the southern extremity of the network. Table 1.4 below provides the expected inlet pressure to this regulator based on the two growth scenarios outlined above.

Table 1.2: DCP Pipeline minimum pressure (kPa)

Location	2016	2017	2018	2019	2020	2021	2022	Design Min
Dunns Road Scenario 1 – 1100 per year	1,194	1,161	1,113	1,062	1,031	982	948	**1050**
Dunns Road Scenario 2 - 1600 per year	1,169	1134	1083	1030	995	942	906	**1,050**

The impact of a higher connection rate (Scenario 2) would bring forward the timing of augmentation by about twelve months. For planning purposes it is assumed that network augmentation will be required ahead of the 2020 winter.

The Dunns Road TP/HP regulator supplies gas to over 14,000 consumers in the Mornington and Mount Martha area. Operating at inlet pressure below 1050 kPa could affect a number of consumers at the extremity of this HP network with potential for:

- transient7 and unpredictable interruptions to gas supply, occurring at increasing frequency year on year; and
- the potential for an outage to result in release of un-combusted natural gas from a burner that was extinguished during the outage but remained open up to the recovery of gas supply, leading to natural gas accumulation in a confined space followed by fire, explosion or asphyxiation.

Taking action to address these issues is consistent with the findings of our stakeholder engagement program which found strong support from workshop participants for AGN to undertake key projects to maintain reliability levels, including 85% of workshop participants indicating their support for this project.

1.4.4. Summary

Continued residential growth in the Mornington Peninsula will require the capacity of the DCP pipeline to be augmented during the next AP. This will be necessary to:

- maintain minimum gas pressures, as set out in the Gas Distribution Code, to maintain a safe and reliable supply of gas to existing customers;
- avoid GSL payments and relight costs associated with gas outages; and
- meet AGN's obligation to supply 'infill' growth across the Mornington Peninsula

1.5. Risk Assessment

A risk assessment of the following scenarios has been undertaken in accordance with the APA Risk Policy and Risk Matrix.

Scenario 1. Organic Tariff V growth has reduced the DCP end of main pressure to below the recommended minimum during the winter peak demand period impacting the capacity of the Dunns Road TP/HP regulator to the extent that supply is lost to up to 10% (1,400) of customers at the network fringes. This is considered a 'possible' event.

Scenario 2. A failure in the single feed section of pipeline downstream from the DCG results in a loss of supply to about 100,000 consumers. This is considered an 'unlikely' event.

Scenario 3. Network pressure at the extremity of the HP network fed by the Dromana TP/HP district regulator drops below the recommended minimum as result of inadequate pressure in the DCP resulting in a monetary loss of supply to a number of

[7] The term 'transient gas outage' is used in this context to refer to the situation where tariff V gas demand outstrips the network's supply capability for a relatively short period of time. This could occur on a gas day if peak demand is too large and the pressure at the end of the network drops to such a low level that customers in the area of low pressure experience an interruption in supply. Once the peak load starts to fall, the network pressures will start to recover and the supply of gas will return to these customers.

customers. This in turn causes a flame out on an appliance (cook top) and the subsequent return of supply results in a gas in building (GIB) incident that remains unnoticed by the occupant resulting in a fire or explosion. This is considered to be a 'rare' event.

Table 1.5 below summarises the risks associated with these three scenarios. A detailed breakdown of the risk assessment has been provided in Appendix B.

Table 1.3: Risk Rating

Risk Area	Untreated Risk Scenario 1	Untreated Risk Scenario 2	Untreated Risk Scenario 3
Health and Safety	N/A	N/A	Moderate
Environment	N/A	N/A	Negligible
Operational	High	High	Negligible
Customers	Low	Moderate	Negligible
Reputation	Moderate	High	Moderate
Compliance	Moderate	Moderate	Moderate
Financial	Low	Moderate	Moderate
Overall Risk Rating	**High**	**High**	**Moderate**

The highest risk is associated with the loss of supply as result of inadequate system pressures (Scenario 1) or single point of failure affecting the supply to over 100,000 consumers (Scenario 2).

While there is the potential for an outage to result in the release of un-combusted natural gas from a burner, leading to a fire or explosion the risk is considered 'Moderate' as the likelihood is extremely rare.

AGN has an obligation under its license conditions to assess its asset risks and reduce any 'high' risks to at least 'low' and if not low to 'as low as reasonably practicable', as mandated by AS/NZS 4645.1 2008 Gas Distribution Network – Network Management.

AGN considers the 'high' risk rating associated with supply to the Mornington Peninsula as unacceptable with action required to reduce the risk to at least low.

1.6. Options Considered

AGN has considered the following options to address the capacity and security of supply issues outlined above.

1 Option 1: Allow ongoing growth to decrement the DCP pipeline capacity to the extent that supply loss becomes a more regular event.

2 Option 2: Control the amount of additional load on the network by either limiting connections or implement demand management (turn off during peak periods).

3 Option 3: Complete the duplication of the DCP pipeline by connecting previous duplication to the existing DCG.

4 Option 4: Construct a TP steel pipeline and a new city gate station (alternative supply point to the DCG) and upgrade the operating pressure of the previously duplicated DCP pipeline.

5 Option 5: Same as Option 4, however use a different pipeline alignment to avoid various route issues associated with Option 3.

6 Option 6: Defer augmentation into the following regulatory period

The main difference between options 3, 4 and 5 are the routes through which the new pipeline will be built and the capacity that they will provide. Options 4 and 5 provide more capacity however costs more to develop because of risks with the proposed routes and the cost of an additional city gate station.

Further detail on these options is provided below.

1.6.1. Option 1 – Accept increasing risk of supply loss

Under this option, AGN will continue to accept network connections (as it is required to do under the Code) but do nothing to address the effect on the network design minimum pressures or the single point of failure issue.

1.6.1.1. Cost/Benefit Analysis

The benefit of this option is that it does not give rise to any upfront capital costs. This option would, however, result in AGN contravening its regulatory obligation under the Code to use all reasonable endeavours to

> *"…ensure the minimum pressure is maintained at the distribution supply point".*

and as a result the system design minimum pressures will be breached by an increasing amount and with increasing frequency each year, impacting an increasing number of customers at the extremity of the Mornington Peninsula.

This option does not address:

- *Reliability and security of supply of the network* – Ongoing growth in the area means that connected customers at the network fringes will not have 'un-fettered' use of the gas supply that they have paid for. Not all customers will be impacted equally, creating an inequitable supply privilege gradient where customers closer to the gate get a better level of service at the expense of customers at the network fringe. This is inconsistent with the intent of the gas regulatory framework which is designed to ensure all customers are treated equitably and are provided with access on a non-discriminatory basis. In addition, over 100,000 customers could be at risk of supply loss from a single point of failure.

- *Potential safety issues with the network* – A gas network that is not operating correctly or predictably is an unsafe network. A transient loss of gas gives rise to the risk of the release of un-combusted gas, as operating gas appliances do not necessarily respond to loss of gas by automatically turning off. As free gas is released there is the potential for it to collect in a confined space and eventually catch fire or explode, which poses a risk to human health and safety and property. Doing nothing to address the risk of gas intrusion is inconsistent with Australian Standard AS4645 (Gas Distribution Network Management), which requires that this must be managed to 'low' or 'negligible' and if not to 'as low as reasonably practicable'.

- *Increased Opex as result of GSL payments and relights* - The increased risk of an outage under this option also increases the likelihood that AGN will have to make GSL payments (length interruptions incur a charge of $300 per affected property) and incur costs relighting customers, with the costs of the order of $40 per relight.

Given the risks posed by this option and AGN's regulatory obligations to maintain a safe and reliable supply of gas to customers this option is not considered prudent or viable.

1.6.2. Option 2 – Control / Limit Additional Load

Under this option AGN would not augment the network; instead it would limit network connections and or reduce consumption during peak periods to ensure pressure in the DCP pipeline is maintained above the required minimum for TP/HP regulators to function effectively, ensuring that a safe and reliable supply can be maintained in the downstream HP networks.

1.6.2.1. Cost/Benefit Analysis

Like Option 1, the benefit of this option is that it does not give rise to any upfront capital costs. However, this option is not considered prudent for the following reasons:

- limiting future connections would contravene AGN's regulatory obligation under the Code to connect customers that are with the minor or infill extension areas; and
- existing contracts have not been structured to allow for 'turndown' of supply during peak periods. From a practical point of view it would be near impossible to accurately predict capacity shortfalls with sufficient lead time to allow major consumers to reduce their consumption by shifting to alternative energy sources or curtailing operations.

In addition, this option fails to address the security of supply issue associated with the single point of failure of the DCP pipeline.

1.6.3. Option 3 – Complete the duplication of the DCP pipeline

The third option involves completing the final stage of the DCP duplication from Abotts Road back to the Dandenong City Gate. A staged DN 450 duplication of the DN300 DCP pipeline has been completed over the last 10 years from Abotts Road to Robinsons Road. Refer to Appendix A for details.

The scope of work for this option includes:

- construction of a 4,000 metre DN450 steel TP pipeline;
- tie in into the existing DCG;
- tie in into the existing DN450 pipeline in Abotts Road; and
- installation of pig launching facilities.

Refer to concept design Appendix C - Figure C.1 for details.

This option completes the duplication of the DN300 DCP pipeline from the DCG to Robinsons Road providing a secondary feed to the Mornington Peninsula, mitigating security of supply risks associated with a single point of failure of the existing DN300 pipeline.

1.6.3.1. Cost/Benefit Analysis

The capital cost of this Option 3 is $ 13,771 ($'000, 2016).

The benefit of this option is that it reduces risk of gas outage from 'high' to 'moderate' (refer to Appendix B), and in doing so:

- ensures compliance with AGN's regulatory obligations under the Code by:

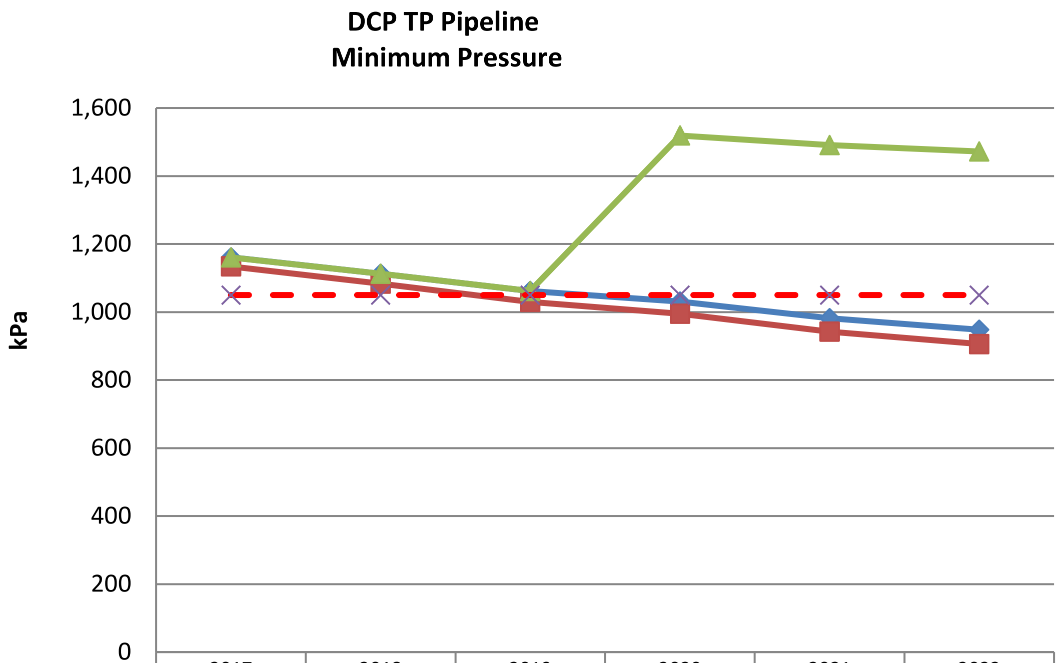
- ensuring that minimum network pressures are maintained at distribution supply points and, in so doing, maintain the integrity of services; and
- allowing new connections to occur (as required by the Code), without risk to gas supply at the network fringe;

- maintains the safety of services by reducing the risk of gas intrusion and the associated risks to human health and safety to as low as reasonably practicable, consistent with Australian Standard AS4645; and
- reduces the likelihood that AGN will have to make GSL payments and incur costs in relighting customers if there is an outage.

The residual risk of moderate is 'as low as reasonably practicable' as there are no further measures that can reduce the risk to 'low'.

The following graph summarises the expected minimum pressure at the inlet to the Dunns Road TP/HP pressure regulating facility.

Figure 1.2: Network Pressure – Post Augmentation



	2017	2018	2019	2020	2021	2022
Scenario1 - Dunns Road	1,161	1,113	1,062	1,031	982	948
Scenario 2 - Dunns Road	1134	1083	1030	995	942	906
Option 3 Augmentation	1,161	1,113	1,062	1519	1491	1472
Required Minimum	1,050	1,050	1,050	1,050	1,050	1,050

This solution provides additional capacity to serve forecast growth for at least the next 10-15 years. It also provides a second source of supply to the area by connecting the existing DN450 pipeline to the DCG enabling gas to be injected into the DN300 pipeline at Robinsons Road. In doing so it significantly reduces the consequence of a single point of failure of the DN300 DCP pipeline.

1.6.4. Option 4 – Connect to the Longford Pipeline

This scope of option involves the construction of a 2,500m x DN450 TP main from the GasNet Longford pipeline tying into the existing AGN DN450 pipeline at Abotts Rd making partial use of an existing pipeline easement (either GasNet T1 or AGN T13). Refer to concept design Appendix Figure C.2 for details.

The connection to the Longford pipeline was chosen over the relatively closer Lurgi (Morwell to Dandenong) pipeline due to its higher operating pressure (MAOP of 6890 kPa versus 2760 kPa). The actual operating pressure of the Lurgi pipeline can at times be lower than the DCP pipeline and as such was not a feasible option.

The existing AGN DN450 pipeline from Abotts Rd to Robinson Rd has been designed for the MAOP of the Longford pipeline however it currently operates at a lower pressure. Upgrading this pipeline and operating it at the MAOP of the Longford pipeline provides the best capacity benefit to the overall network. Based on this configuration a CTM, constructed by GasNet, at the connection point to the Longford pipeline and a TP/TP pressure regulator facility at Robinson Rd connecting to the DCP pipeline is required. The cost of the CTM would be passed onto AGN via an annualised Opex charge while the TP/TP facility would be owned and operated by AGN.

As part of 'proving' the integrity of the existing DN450 pipeline from Abotts Rd to Robinson Rd an ILI is required to confirm its unchanged structural integrity and suitability for operation at its design MAOP. To this end this option includes 'pig' launch and receiving facilities.

The route of this pipeline, although shorter than Option 3 traverses; private property, a concrete carpark, railway crossings, and through an area planned for a future road overpass. This route has significant risks adding to land acquisition and construction costs.

The connection point to the Longford line is relatively low lying and prone to flooding. This would present access issues for the operation and maintenance of the pipeline.

1.6.4.1. Cost/Benefit Analysis

The capital cost of this option is $16,900 ($'000, 2016). Refer to Appendix D Figure D.2 for cost details.

The cost estimate for this solution has several difficult to quantify costs including landowner engagement and compensation, easement and land purchase. The cost assessment excludes costs related to easement sharing, VicTrack licensing and compulsory acquisition if it should be required.

While the route is shorter the total costs are higher as result of:

- Increased difficulty/risk associated with the route (under hardstand, under a road overpass and under a railway line).
- The cost of an additional TP/TP regulating facility

This option addresses the capacity and security of supply issues as outlined for Option 3 with a greater long term capacity (20+ years) than Option 3. It should be noted that Option 3 allows for future connection to the Longford pipeline should additional capacity be required.

The risk of project cost overrun with this option is rated as 'high' because of the route issues outlined above. The cost estimate for this solution has several hard to quantify costs including landowner engagement and compensation, some additional easement costs and land purchase costs. The cost assessment excludes costs related to easements, VicTrack licensing and compulsory acquisition (if required).

Obtaining approvals from regulatory, rail and road authorities for this option may be difficult to obtain in a timely manner increasing the lead time necessary to complete the augmentation. Approvals would be required from:

- ESV for construction within private property
- Rail authorities to cross railway easements
- Road Authorities where the pipeline passes through an area for the planned Pound Road / Remington Drive overpass

By comparison to Option 3, Option 4 does not provide the most cost efficient solution.

1.6.5. Option 5 – Connect to the Longford Pipeline (Alternative Route)

This scope of this option is essentially the same as Option 4 however an alternative, longer route from the Longford pipeline to the existing DN450 pipeline in Abotts Road has been selected to avoid alignment issues associated with Option 4. Refer to the concept design Appendix C - Figure C.3 for details.

1.6.5.1. Cost/Benefit Analysis

The capital cost of this option is estimated at $17,100 ($'000, 2016). Refer to Appendix D Figure D.5 for cost details.

This option addresses the capacity and security of supply issues as outlined for Option 3 with a greater long term capacity (20+ years) than Option 3. It should be noted that Option 3 allows for future connection to the Longford pipeline should additional capacity be required.

By comparison to Option 3, Option 5 does not provide the most cost effective solution.

1.6.6. Option 6 – Defer Augmentation

Deferring network augmentation into the following regulatory period (2023 – 2027) has been considered. This would require the acceptance of a high risk, associated with reliability of supply, with AGN not compliant with its obligations to maintain a safe and reliable supply to consumers for several years.

Deferring augmentation would also mean that the integrity assessment of the 50 year old DN300 DCP pipeline would be deferred several years.

Given AGN's obligations, deferral was not considered a prudent or efficient option.

1.7. Summary of Cost/Benefit Analysis

Table 1.7 below provides a summary of costs, risks and benefits associated with the six options.

Table 1.7: Cost Benefit Summary

Option	Benefits	Costs/Risks
Option 1	Avoids up front capital expenditure (capex).	No capital costs. GSL payments of up to $300 per customer plus $40 per customer for relight in event of a gas outage. AGN would fail to comply with its regulatory obligations under the Code to use all reasonable endeavours to ensure safe and reliable supply of gas to consumers. Residual Risk is 'high' - Not a prudent option
Option 2	Avoids up front capital expenditure.	No capital costs. Impractical to implement - current contracts do not allow for demand management. AGN would fail to comply with its obligation under the Code to connect customers. Residual risk is 'high' - Not a prudent option
Option 3	• Improved security of supply to 100,000 customers. • Ensures AGN complies with the pressure and connection provisions in the Code. • Reduces the risk of gas outages and the associated risks to human health and safety to as low as reasonably practicable. • Maintains the integrity of services.	$13,771 ($000, 2016) Capex Despite the risks associated with extending a TP pipeline through a built up residential this option is considered to have the lowest implementation risk. A lead time of about 3 years is required to minimise the risk of failing to deliver an improved supply on time. This is the lowest cost solution that reduces reliability and security of supply risk to an acceptable level. Risk is reduced from 'High' to 'Moderate' (as low as reasonably practicable). This is the recommended Option based on reducing risk at the lowest cost and relatively low implementation risk.
Option 4	Same as (a)-(d) in Option 3 but higher capacity up front.	$16,200 ($000, 2016) This option reduces reliability and security of supply risk the same as Option 3 at a premium of $2,400k. The route of the pipeline has a number of risks associated with traversing private property, across train lines and in the vicinity of a proposed major motorway. There is a significant risk that construction costs would increase from the estimate provided. This Option has been rejected based on cost.

Option 5	Same as (a)-(d) in Option 3 but higher capacity up front.	$17,100 ($000, 2016) This option reduces reliability and security of supply risk the same as Option 3 at a premium of $3,300k This Option is essentially Option 4 with a revised pipeline route to avoid risks associated with Option 4 This Option has been rejected as based on cost.
Option 6	Deferral creates time value of money savings	No capital costs in the next regulatory period AGN would fail to comply with its regulatory obligations under the Code to use all reasonable endeavours to ensure safe and reliable supply of gas to consumers. Residual Risk is 'high' (until augmentation is effected) - Not considered prudent

1.8. Proposed Solution

1.8.1. What is the proposed solution?

The proposed solution is Option 3, a 4,000 metre x DN450 steel TP pipeline, completing the duplication of the DCP pipeline from the DCG to Robinsons Road.

1.8.2. Why are we proposing this solution?

Option 3 is being proposed because it is the most cost effective way to address the capacity and single point of failure issues in this part of the network. In doing so it will; maintain and improve the safety of services, maintain the integrity of services, meet existing levels of demand and ensure that AGN complies with its regulatory obligations under the Code.

1.8.3. Stakeholder Engagement

Overall, our customers told us that they value current standards of reliability and are supportive of initiatives that maintain their reliability and improve the safety of the network, with the majority of participants prepared to pay to support the maintenance of the existing level of reliability of the network, with the understanding that upgrades to meet population growth are necessary investments for the supply of gas for Victorian residents into the future.

Projects that support reliability received support from 86% of workshop participants, behind only awareness of AGN assets, ongoing mains replacement program and bushfire preparedness when ranked in order of importance.

More specifically, when presented with the Dandenong Crib Point initiative (at a cost of $1 per annum on their gas bill), 85% of workshop participants were supportive of this project.

Figure 1.3: Stakeholder Engagement Results

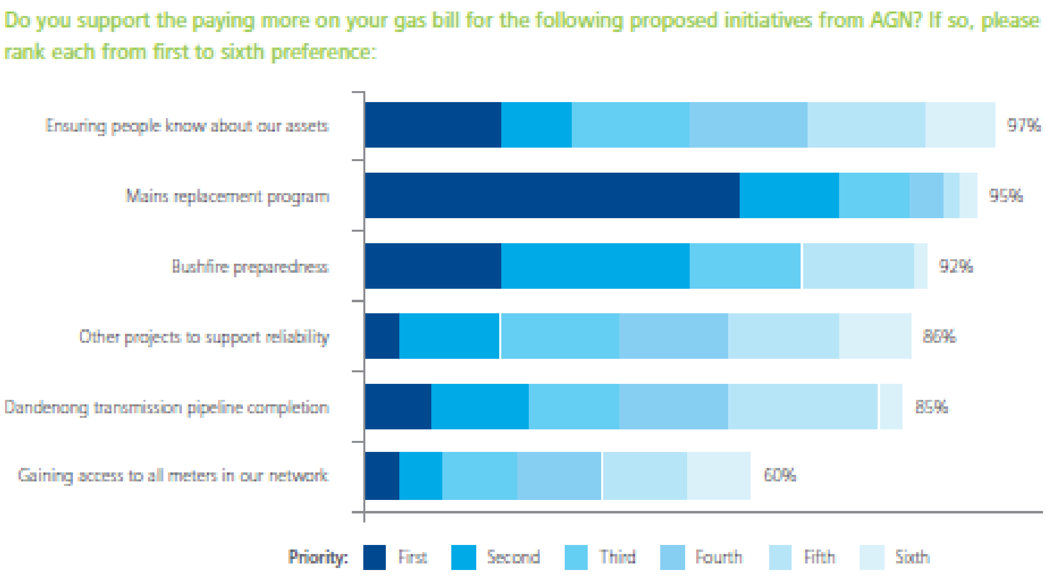


Figure 4: Total workshop support of AGN's proposed initiatives, broken down by preference rank

1.8.4. Forecast Cost Breakdown

The Table 1.8 below summarises Option 3 costs over the next AP (details of project cost are included in Appendix D).

These have been estimated based on:

- *Materials* - Where possible, the cost of the materials required is based on the price achieved for comparable works completed elsewhere in the network. Where a suitable cost estimate from outcomes is unavailable, the material cost is estimated from recent quotes received for other similar works and previous cost experience.
- *Labour* - Where possible the labour costs have been based on the unit rate achieved as the result of competitive tender between external contractors. This is assumed to reflect the best efficient delivery cost achievable. For specialist services, the cost estimate is derived from the cost of due diligence for similar projects.
- *Project Timing* – Projects have been sequenced to ensure manageable project delivery targets while avoiding breaching minimum pressures under design conditions.

Table 1.8: Capex Summary ($000, 2016)

Capex	2018	2019	2020	2021	2022	Total
Materials	1,707	-	-	-	-	**1,707**
Construction	1,696	6,784	3,392	-	-	**11,872**
Miscellaneous Services	192	-	-	-	-	**192**
Total	**3,595**	**6,784**	**3,392**	**-**	**-**	**13,771**

1.8.5. Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the National Gas Rules, AGN considers that the capital expenditure is:

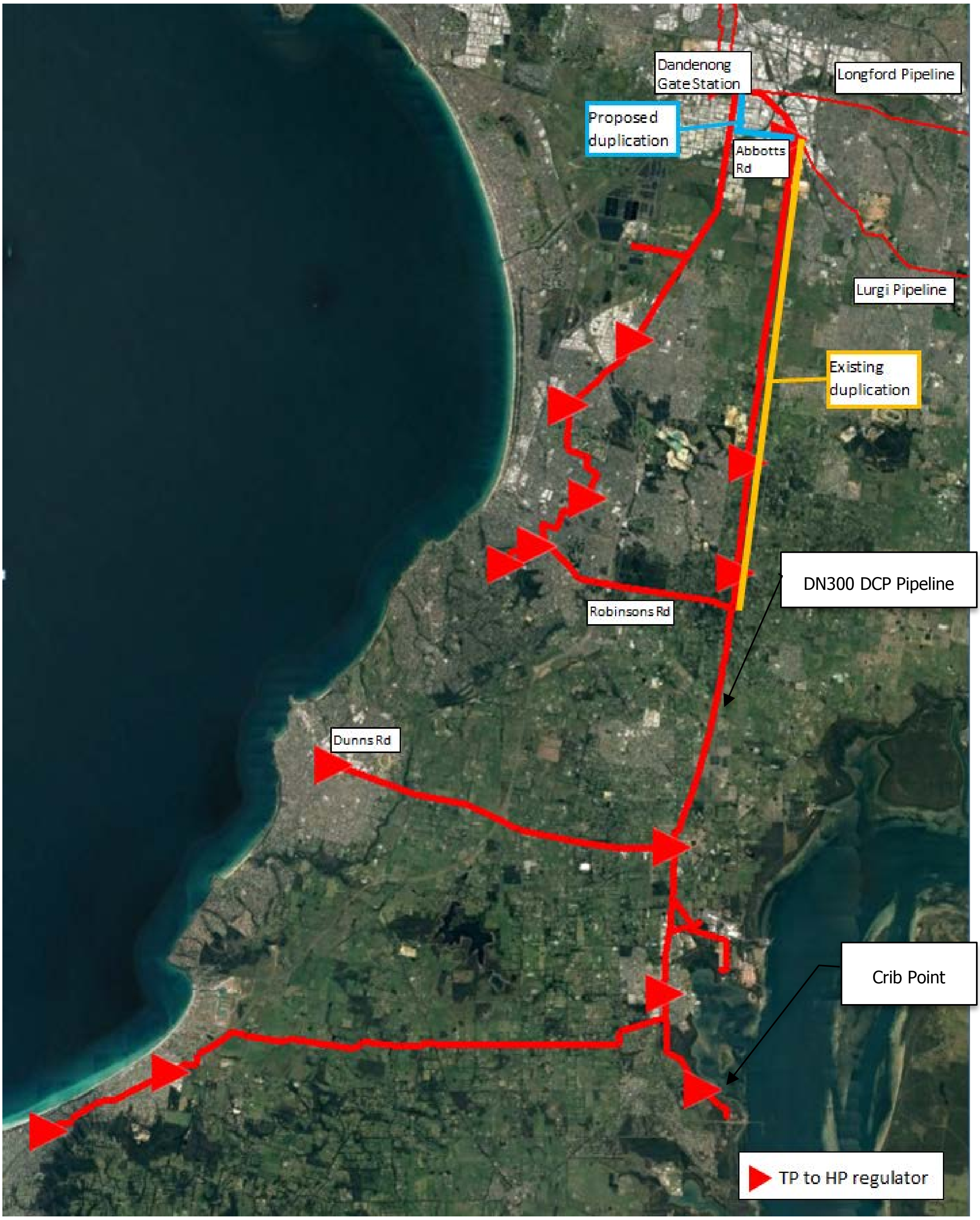
- *Prudent* - The proposed expenditure is necessary to improve the security of supply and ensure that the DCP TP can meet the projected growth in demand. It is also necessary to comply with regulatory obligations and reduce the risk to human health and safety posed by gas outages to as low as reasonably practicable. The proposed expenditure is also of a nature that a prudent service provider would incur as highlighted by the options analysis that has been conducted.
- *Efficient* - The proposed construction of a 4,000m x DN450 steel TP pipeline is the most cost effective way of addressing the capacity and single point of failure issues. The proposed expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur. The manner in which AGN intends to carry out the work (i.e. field work to be carried out by an external contractor that has demonstrated specific expertise in completing the installation of the assets in a safe and cost effective manner and that will be selected through a competitive tender) can also be considered efficient.
- *Consistent with good industry practice* - Complying with the obligations set out in the Code by carrying out the proposed augmentation is consistent with accepted and good industry practice. So too is reducing:
  - the supply risk by addressing the single point of failure; and
  - the risk to human health and safety posed by gas outages to as low as reasonably practicable in a manner that balances cost and risk as required by Australian Standard AS/NZS 4645 (Gas Distribution Network Management).
- *Achieve the lowest sustainable cost of providing the service* - The scale of the proposed augmentation is designed to match the network requirements, balancing the objectives of minimising community disruption during construction and the need to revisit augmentation within a short time without overinvesting in the network. Proactively addressing emerging gas supply issues will avoid multiple reactive measures, thereby ensuring the lowest long-term sustainable cost for customers. Continuing to expand the network ensures that operating costs are spread over an increasing number of customers, helping to drive down the average cost per customer.

The capex can therefore be viewed as being consistent with rule 79(1)(a) of the NGR. The proposed capex is also consistent with rule 79(1)(b) because it is necessary to:

- *maintain and improve the safety of services (79(2)(c)(i))* – if more connections to the network occur without corresponding augmentation of the network, then the risk of transient gas outages and the associated risk to human health and safety will increase;
- *maintain the integrity of services (79(2)(c)(ii))* – if the minimum pressure of the network is not maintained through augmentation, customers will face interruption reducing the reliability (integrity) of current services. The augmentation also reduces the risk of major supply outage from a single point of failure; and
- *comply with a regulatory obligation (79(2)(c)(iii)) –* AGN is required by the Code to maintain minimum pressures and to continue to connect new customers located in 'minor infill' areas.

Appendix A DCP Supply Network Overview

Figure A.1 – Dandenong Crib Point Transmission Pipeline



Appendix B Risk Assessment

Figure B.1 – Untreated Risk

Scenario		Health and Safety	Environment	Operations	Customers	Reputation	Compliance	Financial
Scenario 1 - Supply Loss to over 1,000 customers in the HP network from inadequate TP system pressure to Dunns Road TP/HP.	Likelihood	*N/A*	*N/A*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*
	Consequence	*N/A*	*N/A*	*Significant*	*Minor*	*Medium*	*Medium*	*Minor*
	Risk Level	*N/A*	*N/A*	*High*	*Low*	*Moderate*	*Moderate*	*Low*
Scenario 2 - Supply Loss up to 100,000 customers from single point of failure on section of pipeline downstream of DCG	Likelihood	*N/A*	*N/A*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*
	Consequence	*N/A*	*N/A*	*Major*	*Significant*	*Major*	*Significant*	*Medium*
	Risk Level	*N/A*	*N/A*	*High*	*Moderate*	*High*	*Moderate*	*Moderate*
Scenario 3 - GIB incident from transient supply loss	Likelihood	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*
	Consequence	*Major*	*Minor*	*Minor*	*Minor*	*Major*	*Major*	*Medium*
	Risk Level	*Moderate*	*Negligible*	*Negligible*	*Negligible*	*Moderate*	*Moderate*	*Moderate*

Figure B.2 – Treated Residual Risk

		Health and Safety	Environment	Operations	Customers	Reputation	Compliance	Financial
Option 3 (Recommended Augmentation) Scenario 1 - Supply Loss to over 1,000 customers in the HP network from inadequate TP system pressure to Dunns Road TP/H .	Likelihood	*N/A*	*N/A*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*
	Consequence	*N/A*	*N/A*	*Significant*	*Minor*	*Medium*	*Medium*	*Minor*
	Risk Level	*N/A*	*N/A*	*Moderate*	*Negligible*	*Low*	*Low*	*Negligible*
Option 3 (Recommended Augmentation) Scenario 2 - Supply Loss risk reduced from 100,000 to less than 10,000 from a single point of failure	Likelihood	*N/A*	*N/A*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*
	Consequence	*N/A*	*N/A*	*Major*	*Significant*	*Major*	*Significant*	*Medium*
	Risk Level	*N/A*	*N/A*	*Moderate*	*Moderate*	*Moderate*	*Moderate*	*Low*

Appendix C Concept Designs

Figure C.1 - Option 3: 4 km DN450 DCG to Abotts Rd

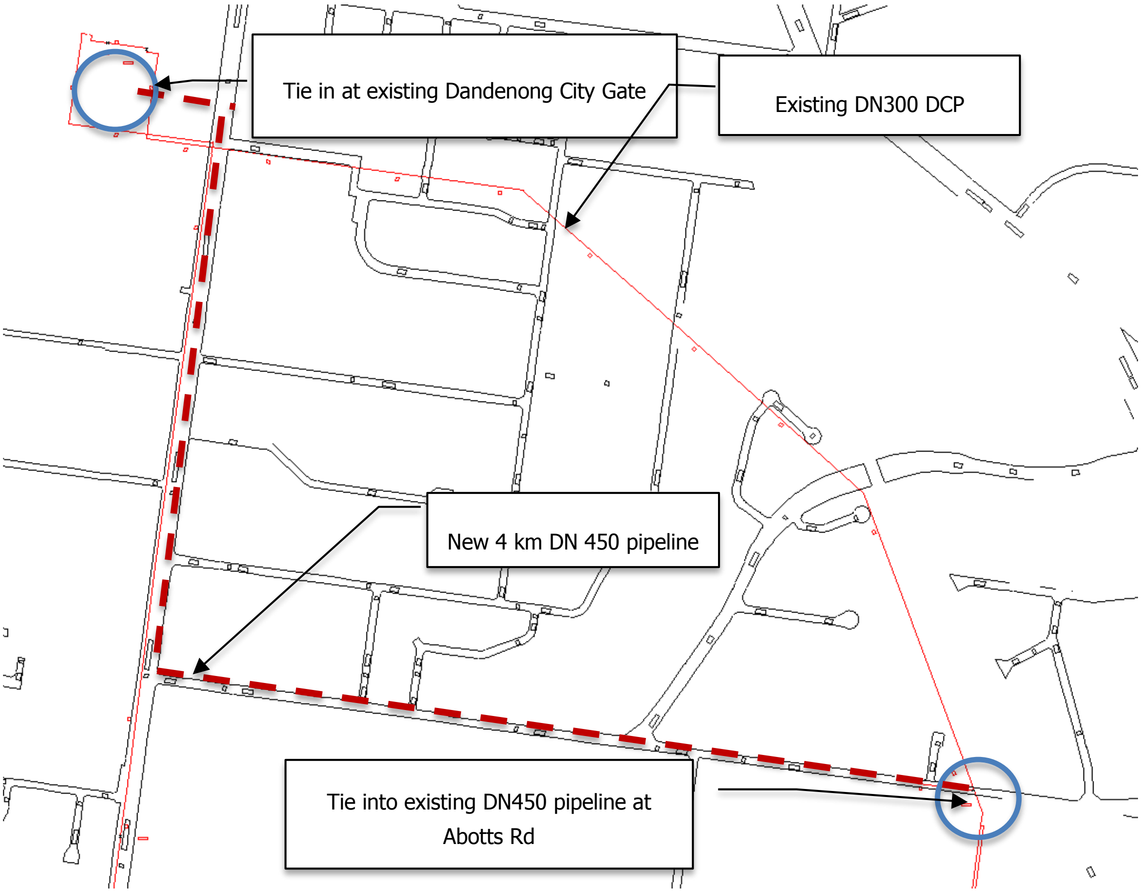


Figure C.2 - Option 4: 2.5 km DN450 DCG to Abotts Rd + New City gate

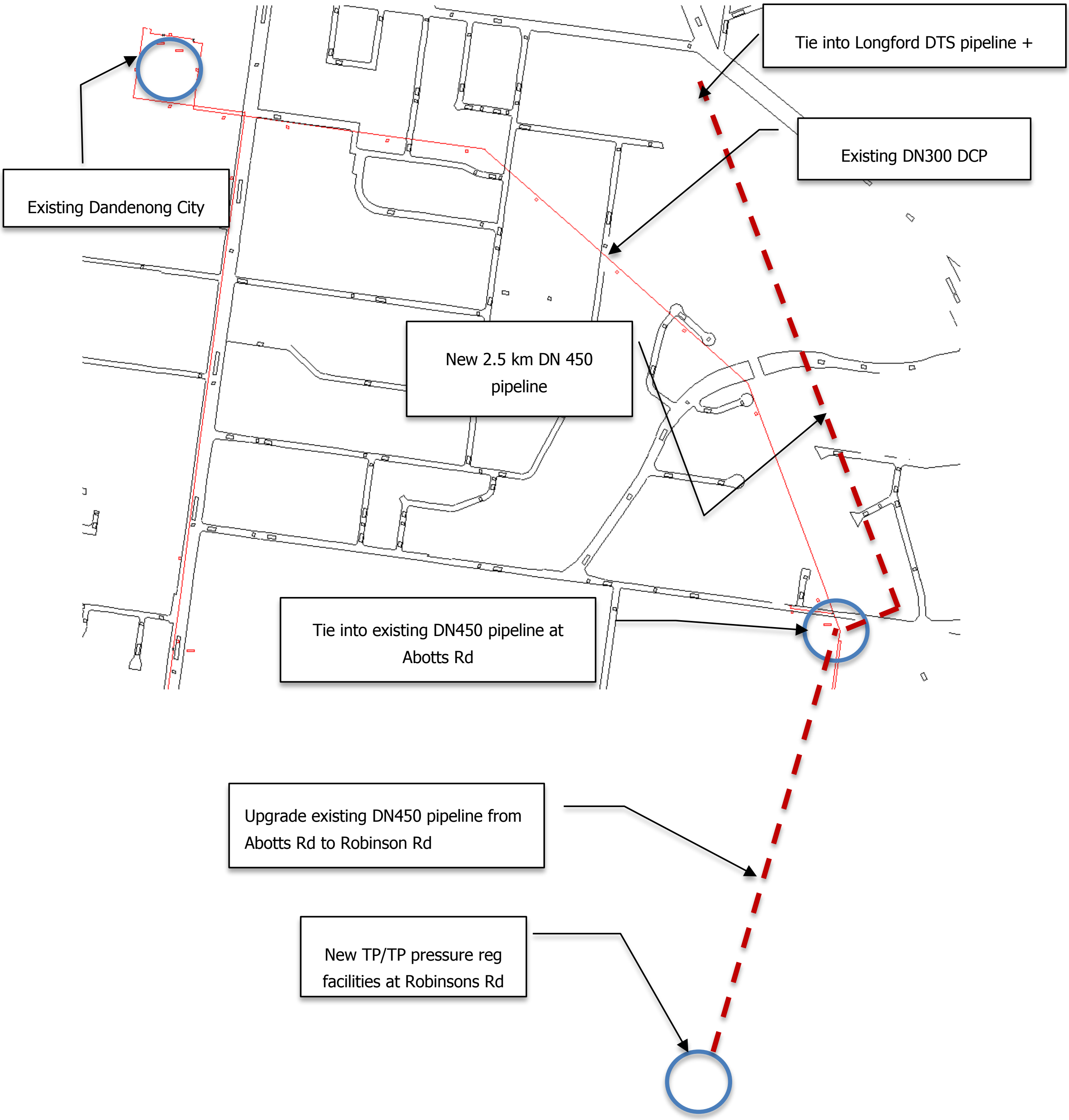
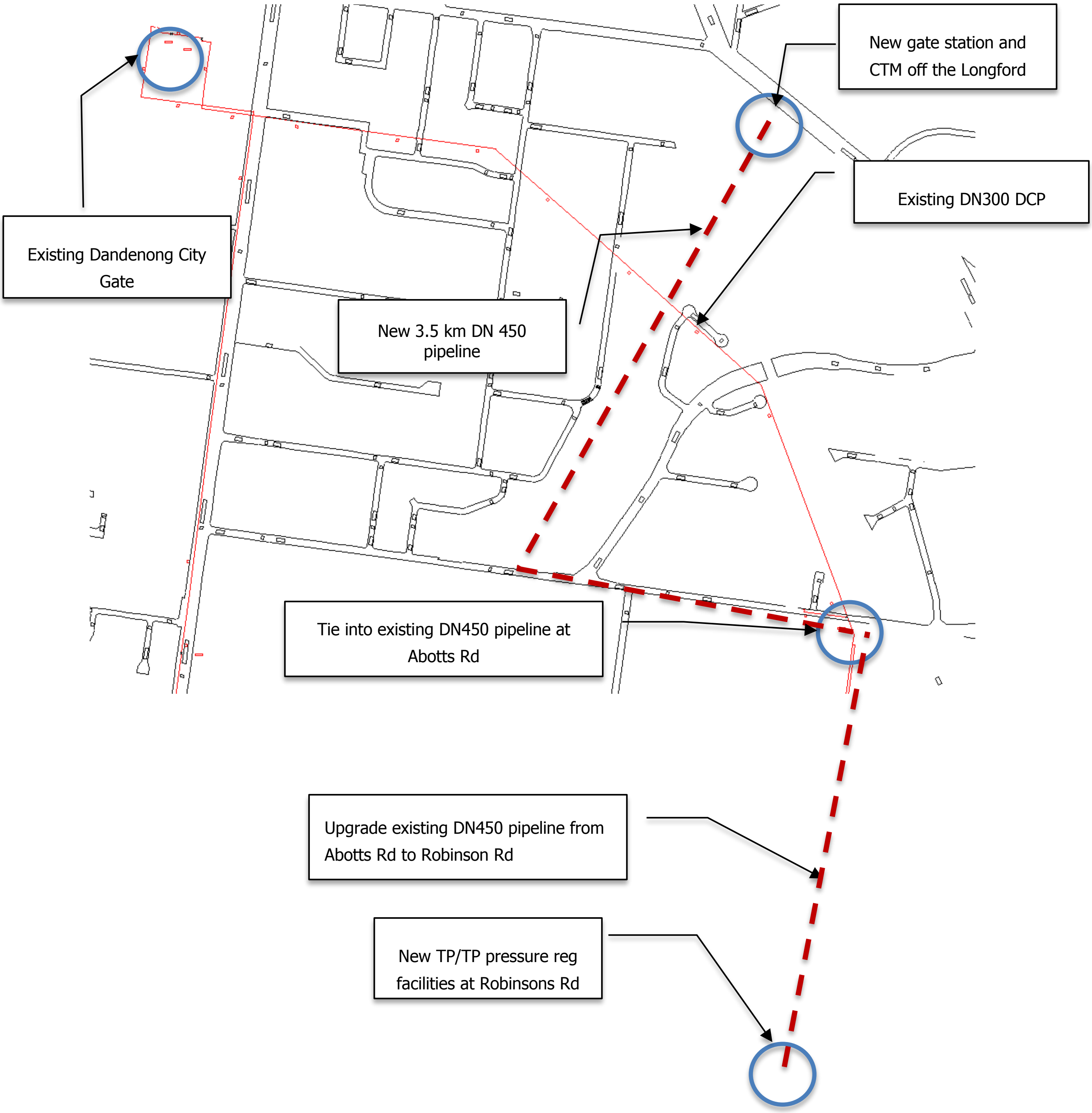


Figure C.3 - Option 5: 3.5 km DN450 DCG to Abotts Rd + New City gate



Appendix D Cost Breakdown

Table D.1: Option 3 Cost Estimate

PROJECT: DANDENONG CRIB POINT AUGMENTATION (OPTION 3)				
ITEM	**Units**	**UOM**	**$/unit**	**ITEM COST**
MATERIALS				
Hot Formed Bends	7	ea	$6,872	$48,104
DN450 - Pipe	420.6393	tonne	$1,870	$786,654
Pipe Coating	6567502	$m.mm^2$	$0	$388,553
Rock Jacket Coating	6535739	$m.mm^2$	$0	$25,117
Insulation Joints	2	ea	$12,640	$25,280
CP Equipment	1	lot	$5,600	$5,600
Valves	4	ea	$56,869	$227,477
Pig Trap	2	ea	$99,961	$199,921
Materials Sub Total				**$1,706,706**
CONSTRUCTION				
Pipeline Construction	71.9685	in.km	$99,988	$7,195,958
Facility Station Construction	2	ea	$1,758,088	$3,516,175
Construction Sub Total				**$10,712,133**
MISCELLANEOUS				
License Fee	1676.6	unit	$14	$22,802
Licence Application	528	unit	$14	$7,181
Environmental Approvals	1	lot	$130,500	$130,500
Land Access	1	lot	$31,600	$31,600
Miscellaneous Sub Total				**$192,083**
Total Direct Costs				**$12,610,922**
MANAGEMENT				
Engineering, Procurement, Project Management (9.2% of Direct Costs)	9.2	%		$1,160,205
Management Total				**$1,160,205**
TOTAL ESTIMATED PROJECT COST				**$13,771,127**

Table D.2: Option 4 Cost Estimate Summary

Augmentation Cost Estimate Summary DANDENONG CRIB POINT (OPTION 4)	Part 1 Pipeline	Part 2 CTM & Pressure Regulator Facilities	Total
MATERIALS	$1,355,655	$1,737,776	$3,093,431
CONSTRUCTION	$9,113,309	$1,407,599	$10,520,908
MISCELLANEOUS	$911,383	$0	$911,383
MANAGEMENT	$1,046,992	$629,075	$1,676,067
Total	$12,427,339	$3,774,449	$16,201,788

Table D.3: Option 4 – Pipeline Cost Estimate

PROJECT: DANDENONG CRIB POINT AUGMENTATION (OPTION 4) Part 1 - Pipeline

ITEM	Units	UOM	$/unit	ITEM COST
MATERIALS				
Hot Formed Bends	5	ea	$6,872.00	$34,360
DN450 - Pipe	262.8996	tonne	$1,870.14	$491,659
Pipe Coating	4104689	$m.mm^2$	$0.06	$242,846
Rock Jacket Coating	6718985	$m.mm^2$	$0.0038	$25,821
Insulation Joints	2	ea	$12,640	$25,280
CP Equipment	1	lot	$3,500	$3,500
Valves	5	ea	$56,869	$284,346
Pig Trap	2	ea	$99,961	$199,921
Stopple Fitting	1	ea	$47,667	$47,667
TOR	1	ea	$255	$255
Materials Sub Total				**$1,355,655**
CONSTRUCTION				
Construction	121636.6	in.km	$45	$5,471,251
Facility Station Construction	2	ea	$1,758,088	$3,516,175
Hot Tap Excavation	108.04	m^3	$412	$44,512
Hot Tap Mobilisation	1	lot	$27,000	$27,000
Hot Tap Installation	1	lot	$11,849	$11,849
Live Welding	46.18	hrs	$921	$42,522
Construction Sub Total				**$9,113,309**
MISCELLANEOUS				
License Fee	1676.6	unit	$14	$22,802
Licence Application	528	unit	$14	$7,181
Environmental Approvals	1	lot	$132,500	$132,500
Land Access	1	lot	$748,900	$748,900
Miscellaneous Sub Total				**$911,383**
Total Direct Costs				**$11,380,347**
MANAGEMENT				
Engineering, Procurement, Project Management (9.2% of Direct Costs)	9.2	%		$1,046,992
Management Total				**$1,046,992**
TOTAL ESTIMATED PROJECT COST				**$12,427,339**

Table D.4: Option 4 - Facilities Cost Estimate

PROJECT: DANDENONG CRIB POINT AUGMENTATION (OPTION 4) Part 2 - CTM and Pressure Regulating Facilities				
ITEM	**Units**	**UOM**	**$/unit**	**ITEM COST**
MATERIALS				
Bare Pipe	11.79809	tonne	$1,870	$22,064
Coating	190360.7	m.mm^2	$0	$11,262
MIJ	2	ea	$12,647	$25,294
Manual Valves	11	ea	$56,909	$626,002
Actuated Valves	3	ea	$73,277	$219,831
Regulating Valves	4	ea	$111,964	$447,856
Ultrasonic Flow Meters	1	ea	$97,402	$97,402
Instrument Gas Panels	1	ea	$29,795	$29,795
Slamshut Panels	2	ea	$15,520	$31,040
Pneumatic Control Panel	2	ea	$7,990	$15,980
Switchboard	1	ea	$30,000	$30,000
Battery System	1	ea	$35,000	$35,000
Control Panel	1	ea	$86,250	$86,250
SCADA Communications Equipment	1	lot	$20,000	$20,000
Instrumentation	1	lot	$40,000	$40,000
Materials Sub Total				**$1,737,776**
CONSTRUCTION				
81% of materials Cost	81	%		$1,407,598.56
Construction Sub Total				**$1,407,599**
MISCELLANEOUS				
Miscellaneous Sub Total				**$0**
Total Direct Costs				**$3,145,375**
MANAGEMENT				
Engineering, Procurement, Project Management (20% of Direct Costs)	20	%		$629,075
Management Total				**$629,075**
TOTAL ESTIMATED PROJECT COST				**$3,774,449**

Table D.5: Option 5 Cost Summary

Augmentation Cost Estimate Summary DANDENONG CRIB POINT (OPTION 5)	Pipeline	CTM & Pressure Regulator Facilities	Total
MATERIALS	$1,678,345	$1,737,776	$3,416,121
CONSTRUCTION	$10,299,070	$1,407,599	$11,706,669
MISCELLANEOUS	$227,613	$0	$227,613
MANAGEMENT	$1,122,863	$629,075	$1,751,937
Total	$13,327,891	$3,774,449	$17,102,340

Table D.6: Option 5 – Pipeline Cost Estimate

PROJECT: DANDENONG CRIB POINT AUGMENTATION (OPTION 5)
Part 1 - Pipeline

ITEM	Units	UOM	$/unit	ITEM COST
MATERIALS				
Hot Formed Bends	9	ea	$6,872.00	$61,848
DN450 - Pipe	368.0594	tonne	$1,870.14	$688,323
Pipe Coating	5746564	m.mm²	$0.06	$339,984
Rock Jacket Coating	6718985	m.mm²	$0.00	$25,821
Insulation Joints	2	ea	$12,640.00	$25,280
CP Equipment	1	lot	$4,900.00	$4,900
Valves	5	ea	$56,869.18	$284,346
Pig Trap	2	ea	$99,960.63	$199,921
Stopple Fitting	1	ea	$47,666.77	$47,667
TOR	1	ea	$255.00	$255
Materials Sub Total				**$1,678,345**
CONSTRUCTION				
Construction	105713.1	in.km	$62.97	$6,657,012
Facility Station Construction	2	ea	$1,758,087.74	$3,516,175
Hot Tap Excavation	108.04	m³	$412.00	$44,512
Hot Tap Mobilisation	1	lot	$27,000.00	$27,000
Hot Tap Installation	1	lot	$11,849.17	$11,849
Live Welding	46.18	hrs	$920.78	$42,522
Construction Sub Total				**$10,299,070**
MISCELLANEOUS				
License Fee	1676.6	unit	$13.60	$22,802
Licence Application	528	unit	$13.60	$7,181
Environmental Approvals	1	lot	$169,500.00	$169,500
Land Access	1	lot	$28,130.00	$28,130
Miscellaneous Sub Total				**$227,613**
Total Direct Costs				**$12,205,028**
MANAGEMENT				
Engineering, Procurement, Project Management (9.2% of Direct Costs)	9.2	%		$1,122,863
Management Total				**$1,122,863**
TOTAL ESTIMATED PROJECT COST				**$13,327,891**

Business Case – Capex V28

H07 Cranbourne

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	Keith Lenghaus, *Asset Planning Manager*
Approved By	Andrew Foley, *General Manager Victorian Networks*

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	The Cranbourne high pressure (HP) network supplies gas to the broader Cranbourne area located on the south-eastern fringe of Melbourne. This area is one of the fastest growing residential zones within Australian Gas Networks' (AGN's) network reach. Continuing residential and commercial growth within the area is expected to reduce pressures within the Cranbourne HP network to below the recommended minimum considered essential to maintain a safe and reliable supply of gas to consumers. Operating below the recommended minimum pressure could result in the loss of several hundred consumers. In circumstances where there is a momentary loss of supply there is a risk that this could lead to a gas in building incident causing major damage and or life threatening injuries. The risk associated with gas outage has been assessed as 'high'. Augmentation of the network is required to meet AGN's obligations to: • Maintain network pressures above the distribution supply point minimum specified in the Victorian Distribution System Code (Code). Failure to do so would be considered a breach of AGN's license condition. • Maintain and improve the safety of services to consumers – Failure to do so could result in serious injury or damage to property • Maintain a reliable supply to consumers – Failure to do so would incur Guaranteed Service Level (GSL) payments and have potential, in the long term, to harm the reputation of natural gas as a reliable energy source promoting consumers to switch to alternatives. • Connect customers that are within minor or infill areas as required by the Code – Failure to do so would be considered a breach of AGN's license condition Viewed in this way augmentation of the Cranbourne network is required to: • comply with the regulatory obligations set out in the Code; and • maintain and improve the safety and reliability of services.
Options Considered	The following options have been considered: 1 Option 1: Allow ongoing growth to decrement capacity to the extent that supply loss becomes a more regular event 2 Option 2: Control the amount of additional load of the network by either. limiting connections or implement demand management (turn off during peak periods) 3 Option 3: Staged augmentation of the network

	4 Option 4: Defer augmentation into the following regulatory period Options 1, 2, and 4 are not considered feasible given AGN's regulatory obligations to maintain a safe and reliable supply of gas to consumers. Option 3 is the only feasible solution which maintains a safe and reliable gas supply to existing consumers while supporting new connections to the existing network.
Proposed Solution	Option 3 consists of a program of augmentation works (nine separate projects) ranging from small to relatively large new mains, to new gate stations aligned with expected future residential developments. This option has been selected because it is the most effective way to comply with regulatory obligations set out in the Code to maintain a safe and reliable supply of gas to customers. This option reduces the risk from 'high' to 'low' consistent with obligations under Australian Standard AS/NZ 4645.
Estimated Cost	The forecast capital expenditure over the next AA period for Option 3 is $8,767 ($'000 2016).
Consistency with the National Gas Rules (NGR)	The augmentation complies with the new capital expenditure (capex) criteria in rule 79 of the National Gas Rules (NGR) because: • it is necessary to maintain and improve the safety of services and maintain the integrity of services and comply with a regulatory obligation (rules 79(2)(c)(i),(ii) and (iii)); 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	AGN has undertaken a comprehensive stakeholder engagement program to better understand the needs and values of our stakeholders and customers. During this engagement, customers told us that they value current standards of reliability and are supportive of initiatives that maintain their reliability and improve the safety of the network. Implementation of this initiative will allow AGN to maintain the safety of the network while continuing to provide a highly reliable supply of natural gas to our customers. More information detailing the results of AGN's stakeholder engagement program is provided in Chapter 5 of the Access Arrangement Information document.

1.3. Background

1.3.1. General

The outer metropolitan suburb of Cranbourne, on the south-eastern fringe of Melbourne, is one of AGN's fastest growing networks. This area includes Cranbourne East which was recently reported to be

> *"…the country's largest growing and second-fastest expanding suburb…".*[1]

The network is predominately supplied by two city gates on its northern border with a smaller supply of gas from the Langwarrin HP network at the south-western border. The network supports approximately 30,000 residential customers and six major industrial and commercial customers. An overview map of the network is provided in Appendix A.

[1] http://www.domain.com.au/news/australias-fastest-growing-suburbs-are-on-city-fringes-new-figures-shows-20160330-gnt6ld/ retrieved 31/03/2016

Capacity modelling[2] has confirmed that ongoing demand from residential growth in the area will reduce network pressures to below the minimum required to sustain a safe and reliable supply of gas. The network is currently being augmented through an extension of a trunk main along Narre Warren Rd to Linsell Boulevard with completion by the 2017 winter. Further growth is forecast that is expected to reduce pressures across the network requiring further augmentation over the next AA period.

The remainder of this section details our obligations and explains why there is a need to deliver further augmentation of the Cranbourne network over the next AA period.

1.3.2. Regulatory Obligations and the Cranbourne network

1.3.2.1. Obligation to Maintain Supply Pressure

Under the Code[3], AGN has a regulatory obligation to use all reasonable endeavours to:

> *"…ensure the minimum pressure is maintained at the distribution supply point[4]."*

This requirement covers both distribution and transmission pipelines. In the Cranbourne network, the minimum Distribution System Pressure required by the Code is 140 kPa.[5] Over the next AA period fringe pressures in Cranbourne are expected to fall below the recommended design minimum commencing from the 2018 winter (refer to Table 1.4 for details).

1.3.2.2. Obligation to Connect

AGN also has an obligation under the Code to connect customers that are within the minor infill extension areas.[6] Specifically, clause 3.1(c) of the Code states that:

> *"A Distributor must connect the gas installation of a customer that resides within the minor or infill extension area on fair and reasonable terms and conditions"*

The growth forecast discussed in the Section 1.4.2 is based on projected dwelling construction within areas that would be considered minor or infill extension under the Code.

1.3.2.3. Guaranteed Service Level

In the event that interruptions to supply occur, depending on the circumstances and duration of interruption AGN may be required to make a GSL[7] payment to each affected customer. GSL payment depends on the duration of customer outage with payments of up to $300 applicable for extended outages.

2 H07 2015 Network Capacity Review

3 The Code has been developed by the Victorian Essential Services Commission and applies to all distributors that hold a distribution licence. The Code sets out the minimum standards for the operation and use of the distribution system, which include, amongst other things, minimum standards for connections and augmentations. As stated in the notes to section 3 of the Code, clause 4 of AGN's Gas Distribution Licence requires compliance with this Code.

4 Schedule 1 Part A of the Code

5 This obligation is set out in Schedule 1 of the Code.

6 The term 'minor and infill extension area' is defined in clause 2.1(f) of the Code as an area that is up to 1 km radially from the nearest part of the distribution system main.

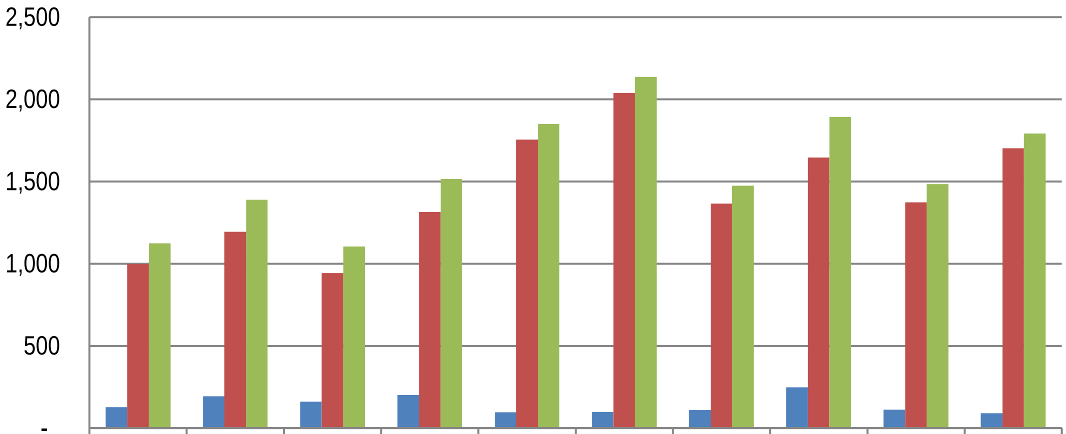
7 The GSL payment is intended to ensure that customers are compensated if an energy distribution company does not meet certain minimum performance standards. The amount payable and the conditions under which a GSL payment is triggered are set out in Part E of the Code. For supply interruptions, repeated or lengthy interruptions would incur a GSL of between $150 and $300 per affected customer. Refer ESC website for a copy of the Code: http://www.esc.vic.gov.au/document/energy/26123-gas-distribution-system-code-2/

1.4. Key Drivers and Assumptions

1.4.1. Historic Growth

The following figure summarises the historic growth in the Langwarrin, Cranbourne and Botanic Ridge (postcodes 3910 and 3977) areas served by the Cranbourne HP network.

Figure 1.1: Meter Connections Historic Growth



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
3910	127	194	161	201	97	98	109	248	112	90
3977	998	1,194	943	1,314	1,754	2,039	1,365	1,646	1,373	1,702
Total	1,125	1,388	1,104	1,515	1,851	2,137	1,474	1,894	1,485	1,792

The five year average net connections from 2011 to 2015 is about 1,756 per year.

1.4.2. Future Demand

A number of sources both internal and external (including Victorian Metropolitan Planning Authority 'Precinct Structure Plans' and forecasted dwelling growth publications from the forecast.id website) have been used to forecast demand in the Cranbourne HP network. Appendix A - Figure 2 provides an overview of future residential developments planned for the area.

The following table summarises the criteria and assumptions used to establish demand in the Cranbourne network over the next Access Arrangement (AA) period.

Table 1.3: Network Modelling Criteria/Assumptions

Criteria/Assumption	Basis
Average annual growth in net new tariff V customer connections of 1,645 per year in Cranbourne, plus 260 per year in the 2 new areas of Clyde North and St Germain	This is based on: • average annual projected growth in dwellings within the Cranbourne network from forecast.id reports (annual average over the period 2016 – 2022); • initial connection uptake rate of 80% of new dwellings; and • housing yield estimates in St Germain and Clyde North • The forecast growth in Cranbourne is in line with the historic 5 year average for that area
Penetration rate of 80%	The ratio of active connections to total delivery supply points has been assessed for the Cranbourne area and found to fall in the range from 80% up to 99%, depending on location. The lower (80%) rate was used as indicative of initial gas connection uptake rates in areas where dwelling construction is underway, and is expected to converge over time towards a final penetration rate of 99% because this is the pattern observed in more developed areas.
No additional Tariff D load	Tariff D Loads arrive unpredictably, and growth in D load has not been allowed for in this analysis. Tariff D load growth will be addressed on an as needed basis, with cost of connection assessed at the time of enquiry.
Average demand per Tariff V customer of 0.9 m^3/hour	New connection peak loads vary from location to location with actual averages of up to 1.2 m3/hr in some parts of the network.

1.4.3. Customer Impact

Continued growth in the Cranbourne area is expected to reduce network pressures at various locations within the Cranbourne HP network over the next AA period. The following Table summarises the impact on network pressures at various fringe point locations.

Table 1.4: Cranbourne Network Minimum Pressure (kPa)

Location	2017	2018	2019	2020	2021	2022	2023
Devon Meadows	260	230	201	129	77	10	**0**
Botanic Ridge	196	156	91	**0**	**0**	**0**	**0**
Langwarrin	215	206	197	188	184	179	**175**
Navarre Drive	265	243	218	154	128	84	**0**
Salerno Way	304	270	232	167	78	**0**	**0**
Cranbourne North	311	251	172	83	**0**	**0**	**0**
Clyde	170	230	205	136	85	9	**0**
Number of customers < 140 kPa	0	0	700	4,500	10,000	15,000	**21,000**
Number of customers nil gas	0	0	100	500	1,500	7,000	**16,600**

The system pressures in 2017 reflect the expected completion and impact of the trunk main augmentation in Narre Warren Rd.

The analysis shows that network pressures are expected to drop below the required minimum from 2019 (Botanic Ridge) and continue to fall across the network over the next AA period.

The final two rows of this table set out:

- the estimated number of customers that could be affected by the reduction in pressure below the 140 kPa Code requirement and could therefore be at risk of a transient gas outage[8]; and
- the estimated number of customers that are at risk of receiving no gas at all if network pressures fall below atmospheric pressure.

It is estimated that up to 15,000 customers could be impacted by poor system pressures by 2022 resulting in:

- transient and unpredictable interruptions to gas supply, occurring at increasing frequency year on year; and
- the potential for an outage to result in release of un-combusted natural gas from a burner that was extinguished during the outage but remained open up to the recovery of gas supply, leading to natural gas accumulation in a confined space followed by fire, explosion or asphyxiation.

Further detail on these risks can be found in Section 1.5.

Taking action to address these issues is consistent with the findings of our stakeholder engagement program which found strong support from workshop participants for AGN to undertake key projects to maintain reliability levels, including 85% of workshop participants indicating their support for this project.

1.4.4. Summary

Continued residential growth in the Cranbourne area will require the capacity of the Cranbourne HP network to be augmented during the next AA period. This will be necessary to:

- maintain minimum gas pressures, as set out in the Gas Distribution Code, necessary for a safe and reliable supply of gas to existing consumers;
- avoid GSL payments and relight costs associated with gas outages; and
- meet AGN's obligation to supply 'infill' growth across the Cranbourne area.

1.5. Risk Assessment

A risk assessment of the following scenarios has been carried out in accordance with the APA Risk Policy and Risk Matrix.

Scenario 1. Organic Tariff V growth has reduced the Cranbourne HP network pressure to below the recommended minimum during the winter peak demand period resulting in the loss of supply to about 7,000 consumers. This is considered an 'occasional' event.

Scenario 2. Network pressure at the extremity of the HP network drops below the recommended minimum resulting in a momentary loss of supply to a number of consumers. This in turn causes a flame out on an appliance (cook top) and the

[8] The term 'transient gas outage' is used in this context to refer to the situation where tariff V gas demand outstrips the network's supply capability for a relatively short period of time. This could occur on a gas day if peak demand is too large and the pressure at the end of the network drops to such a low level that customers in the area of low pressure experience an interruption in supply. Once the peak load starts to fall, the network pressures will start to recover and the supply of gas will return to these customers.

subsequent return of supply results in a gas in building (GIB) incident that remains unnoticed by the occupant resulting in a fire or explosion. This is considered to be a 'rare' event.

Table 1.5 below summarises the risks associated with these two scenarios. A detailed breakdown of the risk assessment has been provided in Appendix B.

Table 1.5: Risk Rating

Risk Area	Untreated Risk Scenario 1	Untreated Risk Scenario 2
Health and Safety	N/A	Moderate
Environment	N/A	Negligible
Operational	High	Negligible
Customers	Low	Negligible
Reputation	Moderate	Moderate
Compliance	Moderate	Moderate
Financial	Low	Moderate
Untreated Risk Rating	**High**	**Moderate**

The highest risks are associated with the loss of supply as result of inadequate system pressures (Scenario 1).

While there is the potential for an outage to result in the release of un-combusted natural gas from a burner, leading to a fire, explosion the risk is considered 'moderate' as the likelihood is 'rare'.

AGN has an obligation under its license conditions to assess its asset risks and reduce any 'high' risks to at least 'low' and if not low 'as low as reasonably practicable', as mandated by AS/NZS 4645.1 2008 Gas Distribution Network – Network Management.

AGN considers the 'high' risk rating associated with supply to Cranbourne as unacceptable with action required to reduce the risk to at least low.

1.6. Options Considered

AGN has considered the following options to address the network capacity issues outlined above.

1 Option 1: Allow ongoing growth to decrement the Cranbourne network capacity to the extent that supply loss becomes a more regular event.

2 Option 2: Control the amount of additional load on the network by either limiting connections or implement demand management (turn off during peak periods).

3 Option 3: Implement a number of small to large augmentation projects, as outlined in Table 1.6, addressing network capacity constraints as and where they occur across the network.

4 Option 4: Defer augmentation into the following regulatory period

The additional option of introducing a new source of gas via an extension from the Bassgas pipeline was considered, but the length of transmission pressure pipeline required made this clearly not economically viable, and the alternative was not developed beyond concept stage.

Further detail on these options is provided below.

1.6.1. Option 1 – Accept increasing risk of supply loss

Under this option, AGN will continue to accept network connections (as it is required to do under the Code) but do nothing to address the effect on the network design minimum pressures.

1.6.1.1. Cost/Benefit Analysis

The benefit of this option is that it does not give rise to any upfront capital costs. This option would, however, result in AGN contravening its regulatory obligation to use all reasonable endeavours to

"ensure the minimum pressure is maintained at the distribution supply point"

and as a result the network design minimum pressures will be breached by an increasing amount and frequency each year, impacting an increasing number of customers in the Cranbourne network.

This option does not address:

- Reduced reliability and security of supply – Connected customers towards the fringe of the network will not have 'un-fettered' use of the gas supply that they have paid for. Not all customers will be impacted equally, creating an inequitable supply privilege gradient where customers closer to the gate get a better level of service at the expense of customers at the network fringe. This is inconsistent with the intent of the gas regulatory framework (including the Access Arrangement framework), which is designed to ensure that all customers are treated equitably and are provided with access on a non-discriminatory basis.
- Potential safety issues with the network – A gas network that is not operating correctly or predictably is an unsafe network. A transient loss of gas gives rise to the risk of the release of un-combusted gas, as operating gas appliances do not necessarily respond to loss of gas by automatically turning off. As free gas is released there is the potential for it to collect in a confined space and eventually catch fire or explode, which poses a risk to human health and safety and property. Doing nothing to address the risk of gas intrusion is inconsistent with Australian Standard AS4645 (Gas Distribution Network Management), which requires that this must be managed to 'low' or 'negligible' and if not to 'as low as reasonably practicable'.
- Increased Opex as result of GSL payments and relights - The increased risk of an outage under this option also increases the likelihood that AGN will have to make GSL payments (lengthy interruptions incur a charge of $300 per affected property) and incur costs relighting customers, with the costs of the order of $40 per relight.

Given the risks posed by this option and the fact that it would result in AGN failing to comply with its regulatory and code obligations to maintain a safe and reliable supply of gas to customers this option is not considered prudent or viable.

1.6.2. Option 2 – Control/Limit Additional Load

Under this option AGN would maintain the current network configuration without augmenting the network and limit network connections and or reduce consumption during peak periods. This would be aimed at ensuring pressures at the extremity of the Cranbourne HP network are maintained above the required minimum ensuring that a safe and reliable supply can be maintained.

1.6.2.1. Cost/Benefit Analysis

Like Option 1, the benefit of this option is that it does not give rise to any upfront capital costs. However, this option is not considered prudent or viable for the following reasons:

- limiting future connections would contravene AGN's regulatory obligation under the Code to connect customers that are with the minor or infill extension areas; and
- existing contracts have not been structured to allow for 'turndown' of supply during peak periods. From a practical point of view it would be impossible to 'predict' capacity shortfalls in the network with sufficient lead time to allow major consumers to reduce their consumption by shifting to alternative energy sources or curtailing operations.

No further consideration has therefore been given to this option.

1.6.3. Option 3 – Staged Network Augmentation

This option involves a programme of work staged over the next AA period that addresses capacity shortfalls as and where they occur within the Cranbourne network. Table 1.6 below summarises the scope, timing and cost of augmentation projects over the next AA period. Refer to Appendix C for a detailed cost breakdown of each project.

Table 1.6: Staged Network Augmentation

Year	Infrastructure	Cost Estimate ($,000 2016)
Gate Infrastructure		
2018	Clyde North: Site selection for new CTM in proximity to existing Tuckers Road P4-166 (Clyde network H49) for supply to the Clyde and Cranbourne network.	426
2018	Clyde North: Site selection for new Customer Transfer Meter (CTM) and city gate in proximity to the Lurgi pipeline and Soldiers Road.	426
2020	Clyde North: Tuckers Road CTM upgrade - Nil capex (annualised GasNet charge included in Opex).	-
2022	Clyde North: Soldiers Road Gate. New CTM – Nil capex (annualised GasNet charge included in Opex).	1,432 -
Mains Infrastructure		
2018	**Botanic Ridge:**	
	120 m of DN125 P7 main from the existing DN125 P7 main in Station Creek Way (near Sandstone Drive), connecting to the existing DN125 P7 main in Station Creek Way near Shearingshed Rise.	43
2019	**Clyde North:**	
	250m of DN200 steel and 540 m of DN180 P8 main from Tuckers Rd City Gate, south along Tuckers Rd to the intersection at Hardys Rd.	495
2019	**Cranbourne East/Clyde North:**	
	720 m of DN180 P7 main from the existing DN180 P7 main in Linsell Blvd near Goulburn St east along Linsell Blvd to Berwick – Cranbourne Rd..	248
2019	**Clyde North:**	
	500 m of DN180 P7 main from the proposed DN180 P7 main on the corner of Linsell Blvd and Berwick – Cranbourne Rd, south along Berwick – Cranbourne Rd to tie in to the 63mm P7 main in Salerno Way.	186
2020	**Langwarrin:**	

	900 m of DN180 P7 main from the existing DN180 P7 in Cranbourne – Frankston Rd south along Kelvin Grove to McKays Road to tie in to the proposed 300mm ST main in McKays Road. Installation of an isolation valve at McKays Road between the proposed 300mm ST main in McKays Road and the proposed DN125 P7 main.	305
2020	**Langwarrin/Cranbourne South: Stage 1**	
	3,000 m of 300mm ST main from the proposed DN125 P7 main in McKays Road, east along McKays Road and Browns Road, then north along Pearcedale Road connecting to the existing DN125 P7 main in Pearcedale Road. Other possible connection would be at Cassinia Close. Complete over two years	1,516
2021	**Langwarrin/Cranbourne South: Stage 2**	
	Completion of 3,000m as above	1,646
2021	**Clyde North – Soldiers Road**	
	1100m of DN300 steel main from the outlet of the new Soldiers Rd City gate, south along Soldiers Rd, tying into the DN180 PE main in Thompsons Rd.	1,301
2022	**Clyde North - Berwick Cranbourne Road**	
	390m of DN180 P8 main from end of existing DN180 main in Berwick Cranbourne Rd north of Thompsons Rd, north along Berwick Cranbourne Rd to tie into mains in Arbourlea Blvd.	175
2022	**Cranbourne East/Clyde North:**	
	1,680 m of DN180 P7 main from the proposed DN180 P7 main at the intersection of Hardys and Tuckers Road, west along Hardys Road to the proposed DN180 P7 main on the intersection of Hardys Road and Berwick – Cranbourne Road.	568
	Total Capital Expenditure	**8,767**

The overall augmentation of the Cranbourne network has been broken down into a sequence of a number of key augmentation projects, most of which can be constructed independently of the others, fitting together into a cohesive network gas delivery strategy aligned with expected future residential developments.

The timing of projects is based on expected future residential growth. If the sequence of development changes, as often is the case, there is flexibility in the augmentation program for various augmentation stages to be re-sequenced.

1.6.3.1. Cost/Benefit Analysis

The capital cost of this Option 3 is $ 8,767 ($'000, 2016).

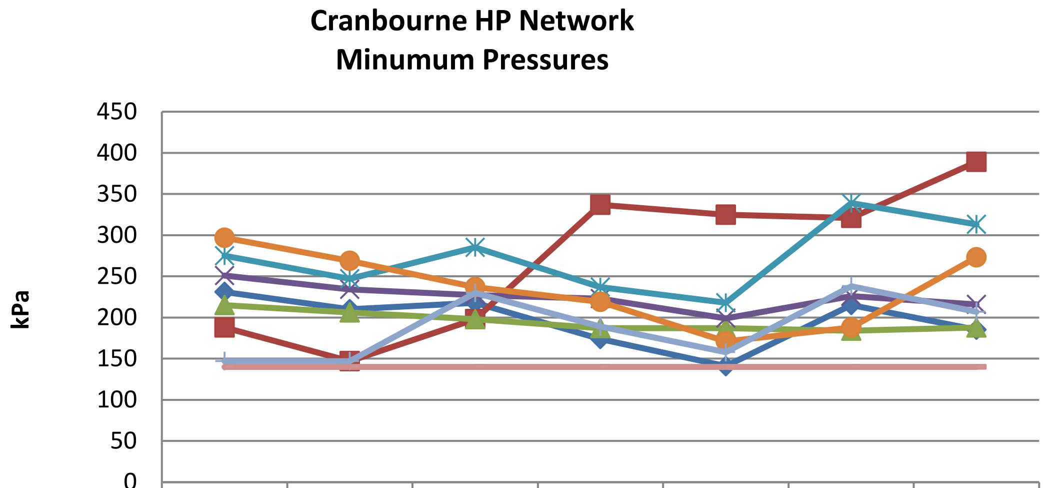
The benefit of this option is that it reduces risk of gas outage from 'high' to 'low' (refer to Appendix B), and in doing so:

- ensures compliance with AGN's regulatory obligations under the Code by:
  - ensuring that minimum network pressures are maintained at distribution supply points and, in so doing, maintain the integrity of services; and
  - allowing new connections to occur (as required by the Code), without risk to gas supply at the network fringe;
- maintains the safety of services by reducing the risk of gas intrusion and the associated risks to human health and safety to as low as reasonably practicable, consistent with Australian Standard AS4645; and

- reduces the likelihood that AGN will have to make GSL payments and incur costs in relighting customers if there is an outage.

Figure 1.2 summarises the expected minimum pressure at various fringe point locations within the Cranbourne HP network given the staged implementation of the program of augmentation projects that represents Option 3.

Figure 1.2: Network Pressure – Post Augmentation



	2017	2018	2019	2020	2021	2022	2023
Devon Meadows	231	210	218	174	141	215	185
Botanic Ridge	188	147	198	337	325	321	389
Langwarrin	215	206	198	187	187	184	188
Navarre Drive	251	234	227	223	199	226	216
Salerno Way	275	247	285	237	218	339	313
Cranbourne North	297	269	237	219	171	188	273
Clyde	147	147	230	189	158	238	207
Required Minimum	140	140	140	140	140	140	140

The program of augmentation works will support growth beyond 2022.

1.6.4. Option 4 – Defer Augmentation

Deferring the augmentation into the following regulatory period (2023 – 2027) has been considered. This would require the acceptance of a 'high' risk of gas outage for several years. AGN would be non-compliant with its obligations to maintain a safe and reliable supply to consumers for the period of delay.

The cost of this option would effectively see Option 3 escalated to the future year of execution, however the rapid growth and development of the Cranbourne area creates a risk that 'deferred' augmentation may incur a premium in the future as it can be more expensive to 'open' roads and acquire land for gate station facilities once the area has been developed.

Given the high risk exposure and potential future cost premium deferral was not a prudent or efficient option.

1.7. Summary of Cost/Benefit Analysis

The table below provides a summary of the costs, risks and benefits associated with the four options.

Table 1.7: Summary of Cost/Benefit Analysis

Option	Benefits	Costs/Risks
Option 1	Avoids up front capital expenditure.	No capital costs. GSL payments of up to $300 per customer plus $40 per customer for relight in event of a gas outage. AGN would fail to comply with its regulatory obligations under the Code to use all reasonable endeavours to ensure safe and reliable supply of gas to consumers. Residual risk is 'high' Not a prudent option
Option 2	Avoids up front capital expenditure.	No capital costs Impractical to implement - contracts do not allow for demand management AGN would fail to comply with its obligation under the Code to connect customers. Not a prudent option
Option 3	Ensures AGN complies with the pressure and connection provisions in the Code. Reduces the risk of gas outages and the associated risks to human health and safety to as low as reasonably practicable. Maintains the reliability of supply to existing consumers.	Capital costs $8,767 ($'000 2016) for a program of work covering 9 augmentation projects ranging from minor to major works. This the recommended option based on reducing risk from 'high' to 'low') at the lowest cost.
Option 4	Deferral creates time value of money savings	No capital costs in the next regulatory period Potential premium for future road openings and land acquisition. AGN would fail to comply with its regulatory obligations under the Code to use all reasonable endeavours to ensure safe and reliable supply of gas to consumers. Residual Risk is 'high' Not considered a prudent option

1.8. Proposed Solution

1.8.1. What is the proposed Solution?

The proposed solution is Option 3, which will involve a sequence of smaller works, most of which can be constructed independently of the others, but which fit together into a cohesive network gas delivery strategy aimed at maintain system pressures above the required minimum.

The scope, timing and costs are summarized in Table 1.6.

1.8.2. Why are we proposing this solution?

Option 3 has been selected because:

- Options analysis shows that it is the most cost effective solution for the network overall. By targeting the trunk main, pressures throughout the network are improved, future proofing the network for capacity regardless of where future growth occurs (see Appendix A Network Overview).
- It is a low risk, technically simple and proven solution – laying pipe in the ground provides a known capacity improvement for an expenditure amount that can be relatively easily and accurately quantified. The risk of delivery is minimal, on both a time and budget basis.

The project is required to comply with regulatory obligations under the Code and is also required to maintain and improve the safety of services and maintain the integrity of the network.

1.8.3. Stakeholder Engagement

Overall, our customers told us that they value current standards of reliability and are supportive of initiatives that maintain their reliability and improve the safety of the network with the majority of participants prepared to pay to support the maintenance of the existing level of reliability of the network, with the understanding that upgrades to meet population growth are necessary investments for the supply of gas for Victorian residents into the future.

Projects that support reliability received support from 86% of workshop participants, behind only awareness of AGN assets, ongoing mains replacement program and bushfire preparedness when ranked in order of importance.

Figure 1.3: Stakeholder Engagement Results

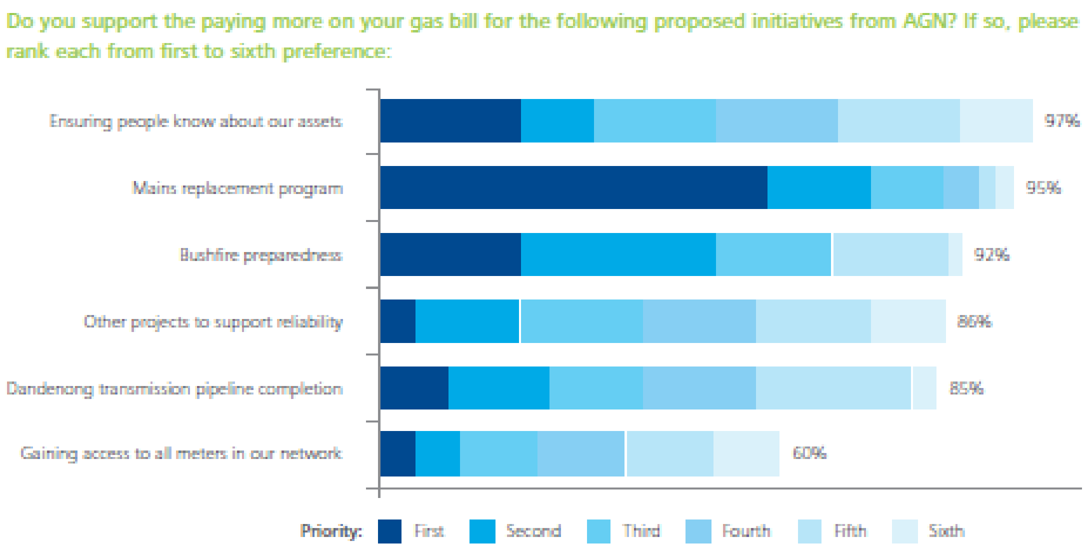


Figure 4: Total workshop support of AGN's proposed initiatives, broken down by preference rank

1.8.4. Forecast Cost Breakdown

Table 1.8 provides a summary of the capex that is forecast to be incurred in the next AA period under Option 3, which has been estimated on the basis of the following assumptions:

- *Materials* – Where possible, the cost of the materials required is based on the price achieved for comparable works completed elsewhere in the network. Where a suitable cost estimate from outcomes is unavailable, the material cost is estimated from recent quotes received for other similar works and previous cost experience.
- *Labour*– where possible the labour costs have been based on the unit rate achieved as the result of competitive tender between external contractors. This is assumed to reflect the best efficient delivery cost achievable. For specialist services, the cost estimate is derived from the cost of basic due diligence for similar projects.
- *Project Timing* – projects have been sequenced to ensure manageable project delivery targets while avoiding breaching minimum pressures under design conditions.

A detailed cost breakdown is provided in Appendix C.

Table 1.8: Capex Split ($000, 2016)

	2018	2019	2020	2021	2022	Total
Land	852	0	0	0	0	852
Materials	2	64.6	486.6	173.2	488.6	1,215
Labour	41	864.4	1334.4	2773.8	1686.4	6,700
Total	**895**	**929**	**1,821**	**2,947**	**2,175**	**8,767**

1.8.5. Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN considers that the capex is:

- *Prudent* - The expenditure is necessary to maintain and improve the safety and integrity of services, and to comply with regulatory obligations. It is also of a nature that a prudent service provider would incur.
- *Efficient* - The cost estimates for this project are based on actual costs for similar works that were awarded via competitive tender. The manner in which AGN intends to carry out the work (i.e. field work to be carried out by an external contractor that has demonstrated specific expertise in completing the installation of the assets in a safe and cost effective manner and that will be selected through a competitive tender) can also be considered efficient.
- *Consistent with good industry practice* - Complying with the obligations set out in the Code by carrying out the proposed reinforcement is consistent with accepted and good industry practice. So too is reducing the risk to human health and safety posed by gas outages to as low as reasonably practicable in a manner that balances cost and risk as required by AS/NZS 4645 (Gas Distribution Network Management).
- *Achieving the lowest sustainable cost* - The scale of augmentation is designed to match the network requirements, balancing the objectives of minimising community disruption during construction and the need to revisit augmentation within a short time without overinvesting in the network. Proactively addressing emerging gas supply issues will avoid multiple reactive measures, thereby ensuring the lowest long-term sustainable cost for customers. Continuing to expand the Network ensures that operating costs are spread over an increasing number of customers, helping to drive down the average cost per customer.

The capital expenditure can therefore be considered consistent with rule 79(1)(a) of the NGR. The proposed capex is also consistent with 79(1)(b), because it is necessary to:

- *maintain and improve the safety of services (79(2)(c)(i))* – if more connections to the network occur without corresponding augmentation of the network, then the risk of transient gas outages and the associated risk to human health and safety will increase;
- *maintain the integrity of services (79(2)(c)(ii))* – if the minimum pressure of the network is not maintained through augmentation customers will face interruption reducing the reliability (integrity) of current services; and
- *comply with a regulatory obligation (79(2)(c)(iii))* – AGN is required by the Code to maintain minimum pressures and to continue to connect new customers located in 'minor infill' areas.

Appendix A Network Overview

Figure A.1 – Cranbourne Network Map

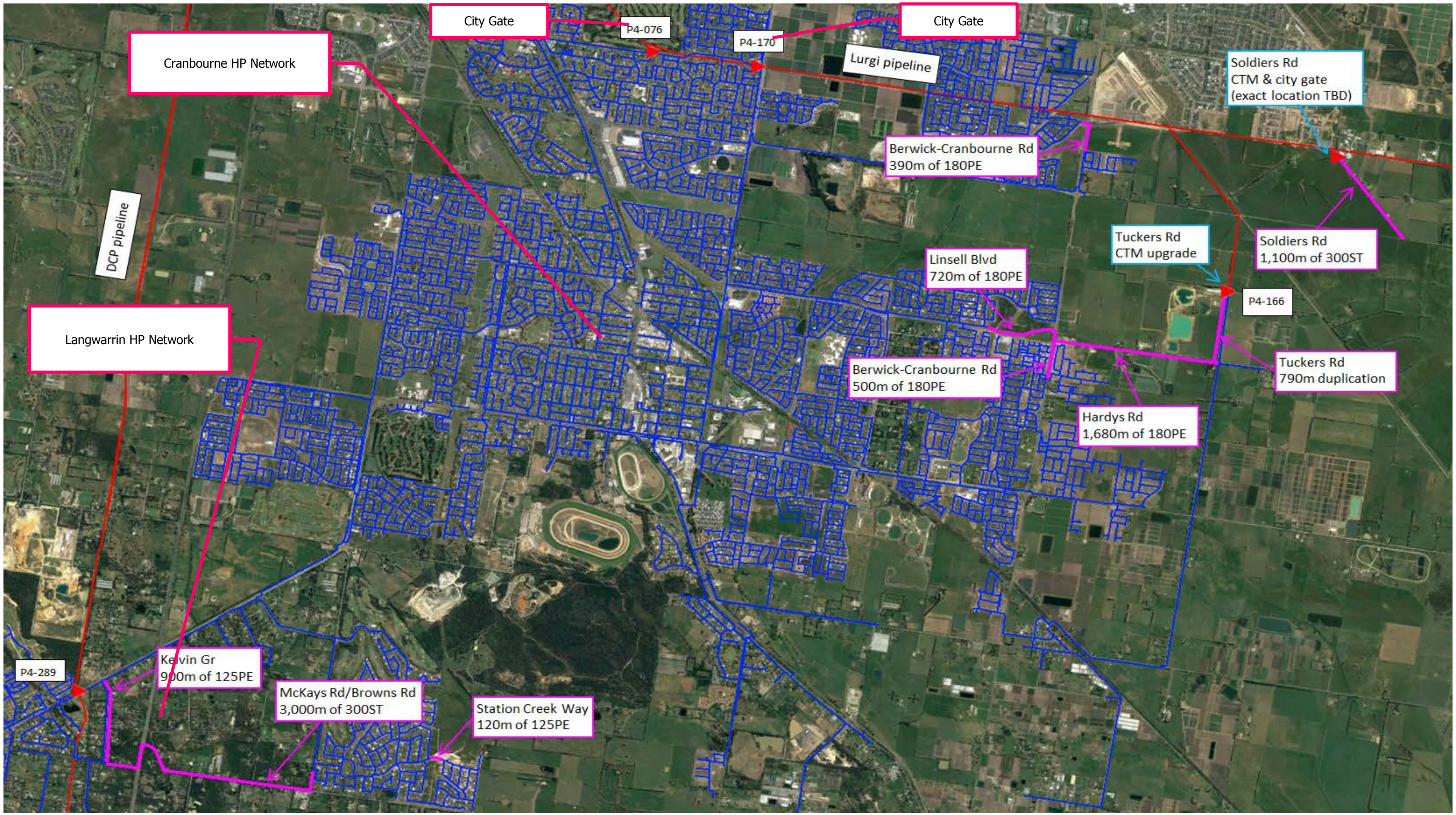
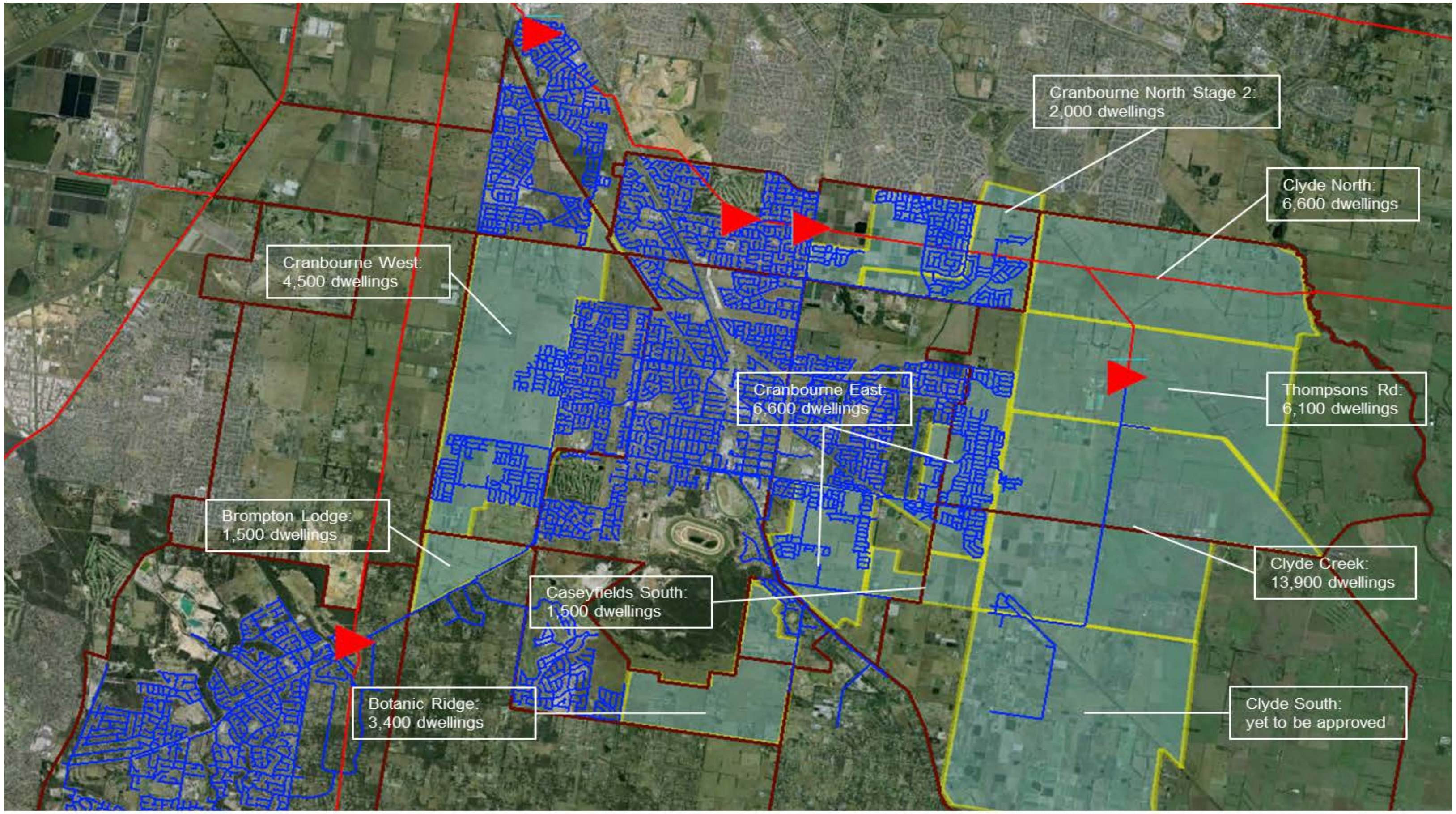


Figure A.2 – Cranbourne Growth Areas



UGB / Development approvals for:

- 6,000 homes in the west of Cranbourne
- 2,000 homes in the north of Cranbourne
- 3,400 homes in Botanic Ridge
- 30,000 homes in the Cranbourne East and Clyde / Clyde North corridor
- Additional developments in PSP Clyde South yet to be approved (but of a similar size to Clyde Creek)

Appendix B Risk Assessment

Table B.1: Untreated Risk

		Health & Safety	Environment	Operations	Customer	Reputation	Compliance	Finance
Scenario 1 – Supply loss 1,000 to 10,000 customers from inadequate system pressure	Likelihood	*N/A*	*N/A*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*
	Consequence	*N/A*	*N/A*	*Significant*	*Minor*	*Medium*	*Medium*	*Minor*
	Risk Level	*N/A*	*N/A*	*High*	*Low*	*Moderate*	*Moderate*	*Low*
Scenario 2 – GIB incident from transient supply loss	Likelihood	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*
	Consequence	*Major*	*Minor*	*Minor*	*Minor*	*Major*	*Major*	*Medium*
	Risk Level	*Moderate*	*Negligible*	*Negligible*	*Negligible*	*Moderate*	*Moderate*	*Moderate*

Table B.2: Treated Residual Risk

		Health & Safety	Environment	Operations	Customer	Reputation	Compliance	Finance
Scenario 1 – Supply loss 1,000 to 10,000 customers from inadequate system pressure	Likelihood	*N/A*	*N/A*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*
	Consequence	*N/A*	*N/A*	*Minor*	*Minor*	*Insignificant*	*Medium*	*Insignificant*
	Risk Level	*N/A*	*N/A*	*Negligible*	*Negligible*	*Low*	*Low*	*Negligible*

Appendix C Detailed Cost Estimate

Table C.1: Cost Estimate - Botanic Ridge

		Capital Projects - Project Cost Estimate				
Project		Botanic Ridge AA Cost Est 2018				
Prepared by		C Taberner				
Date		17.6.16				
Revision		**Botanic Ridge / Cranbourne South**				
Scope of works		Install 120m x 125PE @ 515KPA in Station Creek Way (Crn Sandstone Dr) 125mm P7 to the existing 125mm P7 in Station Creek Way (near Shearing Shed Rise)				
		Air Pressure Test - 2 connections 125mm PE to 125mm PE				
	Item	**Description**	**No Units**	**Units**	**Cost / Unit**	**Total Cost**
Materials	**1**					
Line pipe	1.1	Pipe Plastic DN 125, 12M LG Series 2 PE 100	126	m	$ 13	$ 1,638
Bends, Fittings, Tees etc	1.4	From Materials tab, or factored from pipe & valves				$ 327
Sub-total - Materials						**$ 1,965**
Construction	**2**					
Labour & Equipment	**2.1**					
Standard Contractor Items	**2.2**					
Single trench excavation - Bores	2.2.1	Existing established street - All HDD / Boring Required	120	m	$ 140	$ 16,800
Traffic Management	2.2.2	3 days traffic control required	3	ea	$ 1,166	$ 3,498
Bores in rock	2.2.3	Boring in rock - allow 20% of works - Area known for rock ground conditions	24	m	$ 295	$ 7,080
Bitumen Reinstatement	2.2.5	25% of works (30m x 0.5 trench width) - 15 sqm	15	sqm	$ 143	$ 2,145
Full Reinstatement	2.2.6	Soil and seed (no signs required)	120	m	$ 17	$ 2,006
Proving works		Other utility proving works to confirm alignment - every 50m	3	ea	$ 465	$ 1,396
Others	**2.3**	Tie In / Air pressure test / Commissioning	2	each	$ 824	$ 1,648.00
						$ -
						$ -
Sub-total - Construction						**$ 34,573**
Specialist Services	**3**					
Environmental & CH	**3.1**					
Reports	3.1.1	Site assessments etc		ea		$ 3,000.00
Cultural Heritage review	3.1.2	Site assessments etc		ea		$ 3,000.00
Others	3.1.3	As applicable				$ -
Survey	3.2.2	Description	1	ea	$ 500	$ 500.00
						$ -
Sub-total - Specialist Services						**$ 6,500**
PROJECT TOTAL						**$ 43,038**

Table C.2: Cost Estimate - Clyde North

		Capital Projects - Project Cost Estimate				
Project		Tuckers Rd Clyde Nth AA				
Prepared by		C Taberner				
Date		6.12.16				
Revision						
Scope of works		Install 250m x 200mm ST @ 515KPA in Tuckers Rd Clyde Nth from the proposed City Gate to the proposed 180mm PE in Tuckers Rd Clyde Nth				
		Air Pressure test				
	Item	**Description**	**No Units**	**Units**	**Cost / Unit**	**Total Cost**
Materials	**1**					
Line pipe	1.1	PIPE,METALLIC:219.1MM OD,ERW,8.2MM WALL THK,12M LG,STL,3.275MM THK TRILAMINATE COATED,API 5L GR X42	250	m	$ 73	$ 18,275
Valves	1.2	Major valves - from Materials tab		ea		$ -
Regulators	1.3	Major regulator equipment - from Materials tab		ea		$ -
Bends, Fittings, Tees etc	1.4	From Materials tab, or factored from pipe & valves				$ 3,655
E/I Materials	1.5	From Materials tab - show key items				$ -
CP materials	1.6	From Materials tab - show key items				$ -
Fabricated items	1.7	1 line for each - from Materials tab Includes pipe spools, skids, E/I panels etc etc		ea		$ -
Others	1.8	Pipe Delivery	1		$ 1,800	$ 1,800
						$ -
						$ -
Sub-total - Materials						**$ 23,730**
Construction	**2**					
Labour & Equipment	**2.1**					
APA Labour	2.1.1	Description of general APA labour - 1 line for each category or major activity - includes fitters, techs, construction crews, E/I and SCADA etc		hr		$ -
APA Labour	2.1.2	APA site supervision		hr		$ -
Contractor Labour	2.1.3	Description of general contractor labour - 1 line for each category or major activity Includes Comdain labour, welders etc etc		hr		$ -
Contractor Equipment	2.1.4	Description of general Comdain Equipment rates - excavators, trucks, small equipment etc - 1 line for each		hr		$ -
Commissioning Labour	2.1.5	Description of general APA & contractor labour for commissioning - 1 line for each of APA and Contractor				$ -
Standard Contractor Items	**2.2**					
Single trench excavation	2.2.1	Open Cut -	250	m	$ 504	$ 126,000
Traffic Management	2.2.2	7 days traffic control required	7	ea	$ 1,166	$ 8,162
Bores	2.2.3	1 line for each type Includes thrust bores and HDD		ea		$ -
T D Williamson	2.2.4	TDW Tapping	2	ea	$ 9,862	$ 19,724
Bitumen Reinstatement	2.2.5	10% of works (Tie in point -Hardys Rd seal in future) 79m x 0.5m	0	sqm	$ 143	$ -
Excavation in rock	2.2.6	Excavation in rock (extra over) 20%	50	m	$ 800	$ 40,000
NDT	2.2.7	10% of welds , plus bores and bends	10	ea	$ 1,053	$ 10,530
Hydro Test	2.2.8	Pig / Hyrdro test / Water supply and disposal		ea		$ -
Provings		Prove location of other utility assets - every 50m	5	ea	$ 465	$ 2,327
Others	**2.3**	Tie in proposed 200mm St to proposed 180mm PE crn Hardys Rd and Tuckers Rd	0	each	$ 1,701	$ -
						$ -
						$ -
Sub-total - Construction						**$ 206,743**
Specialist Services	**3**					
Environmental & CH	**3.1**					
Reports	3.1.1	Site assessments etc		ea		$ 7,716
Cultural Heritage review	3.1.2	Site assessments etc		ea		$ 36,605.00
Others	3.1.3	As applicable				$ -
						$ -
Others	**3.2**					$ -
Geotechnical assessment	3.2.1	Description		ea		$ -
Survey	3.2.2	Description	1	ea	$ 900	$ 900.00
Others	3.2.3	Description		ea		$ -
Underground locations	3.2.4	Description		ea		$ -
						$ -
Sub-total - Specialist Services						**$ 45,221**
Project Management and Design	**4**					
Labour	**4.1**					
Consultant Services, Fees & Approvals	**4.2**					$ -
Sub-total - PM and Design						**$ -**
Other	**5**	Insert other items as applicable				
Sub-total - Other						**$ -**
PROJECT TOTAL						**$ 275,694**

		Capital Projects - Project Cost Estimate				
Project		Tuckers Rd Clyde Nth				
Prepared by		C Taberner				
Date		6.12.16				
Revision						
Scope of works		Install 540m x 180mm PE @ 515KPA in Tuckers Rd Clyde Nth from the proposed 200mm steel gas main / City Gate				
		Air pressure test in 1 section				
	Item	**Description**	**No Units**	**Units**	**Cost / Unit**	**Total Cost**
Materials	**1**					
Line pipe	1.1	Pipe, Plastic:DN 180, 12M LG Series 2 PE 100	540	m	$ 27	$ 14,639
Valves	1.2	Major valves - from Materials tab		ea		$ -
Regulators	1.3	Major regulator equipment - from Materials tab		ea		$ -
Bends, Fittings, Tees etc	1.4	From Materials tab, or factored from pipe & valves				$ 2,928
E/I Materials	1.5	From Materials tab - show key items				$ -
CP materials	1.6	From Materials tab - show key items				$ -
Fabricated items	1.7	1 line for each - from Materials tab Includes pipe spools, skids, E/I panels etc etc		ea		$ -
Others	1.8	Others from Materials tab				$ -
						$ -
						$ -
Sub-total - Materials						**$ 17,567**
Construction	**2**					
Labour & Equipment	**2.1**					
APA Labour	2.1.1	Description of general APA labour - 1 line for each category or major activity - includes fitters, techs, construction crews, E/I and SCADA etc		hr		$ -
APA Labour	2.1.2	APA site supervision		hr		$ -
Contractor Labour	2.1.3	Description of general contractor labour - 1 line for each category or major activity Includes Comdain labour, welders etc etc		hr		$ -
Contractor Equipment	2.1.4	Description of general Comdain Equipment rates - excavators, trucks, small equipment etc - 1 line for each		hr		$ -
Commissioning Labour	2.1.5	Description of general APA & contractor labour for commissioning - 1 line for each of APA and Contractor				$ -
Standard Contractor Items	**2.2**					
Single trench excavation	2.2.1	All Direct drill	540	m	$ 173	$ 93,420
Traffic Management	2.2.2	10 days traffic control required	10	ea	$ 1,166	$ 11,660
Bores	2.2.3	1 line for each type Includes thrust bores and HDD		ea		$ -
T D Williamson	2.2.4	Description		ea		$ -
Bitumen cutting	2.2.5	Description				$ -
Bitumen Reinstatement	2.2.6	Description		ea		$ -
Bore in Rock	2.2.7	Bore in rock (extra over) 10% of works	54	ea	$ 800	$ 43,200
Hydro Test	2.2.8	Description		ea		$ -
		Proving of other utllity assets every 50m	11	465		$ 5,115
Others	**2.3**	Tie In / Air pressure test	2	each	$ 1,460	$ 2,920.00
						$ -
						$ -
Sub-total - Construction						**$ 156,315**
Specialist Services	**3**					
Environmental & CH	**3.1**					
Reports	3.1.1	Basic Cultural Heritage Management Plan		ea		$ 7,716
Cultural Heritage review	3.1.2	Site assessments etc		ea		$ 36,605.00
Others	3.1.3	As applicable				$ -
						$ -
Others	**3.2**					$ -
Geotechnical assessment	3.2.1	Description		ea		$ -
Survey	3.2.2	Description	1	ea	$ 900	$ 900.00
Others	3.2.3	Description		ea		$ -
Underground locations	3.2.4	Description		ea		$ -
						$ -
Sub-total - Specialist Services						**$ 45,221**
Project Management and Design	**4**					
Labour	**4.1**					
Consultant Services, Fees & Approvals	**4.2**					$ -
Sub-total - PM and Design						**$ -**
Other	**5**	Insert other items as applicable				
Sub-total - Other						**$ -**
PROJECT TOTAL						**$ 219,103**

Table C.3: Cost Estimate, Clyde East/Clyde North

		Capital Projects - Project Cost Estimate				
Project		Cranbourne East / Clyde NTh AA Cost Est 2019				
Prepared by		C Taberner				
Date		17.6.16				
Revision						
Scope of works		Install 720m x 180PE @ 515KPA in Cranbourne East / Clyde Nth from the existing 180PE in Linsell Bvd crn Goulburn Street, east along Linsell Bvd to Berwick - Cranbourne Rd . Ensure secondary connection to the existing PE in Selardra Bvd (Note, no gas main in Berwick-Cranbourne Rd to tie in to as yet)				
		Air Pressure Test - 2 sections				
	Item	**Description**	**No Units**	**Units**	**Cost / Unit**	**Total Cost**
Materials	**1**					
Line pipe	1.1	Pipe Plastic DN 180, 12M LG Series 2 PE 100	720	m	$ 27	$ 19,440
Bends, Fittings, Tees etc	1.4	From Materials tab, or factored from pipe & valves				$ 3,888
						$ -
Sub-total - Materials						**$ 23,328**
Construction	**2**					
Standard Contractor Items	**2.2**					
Single trench excavation	2.2.1		0	m	$ -	$ -
Traffic Management	2.2.2	13 days traffic control required	13	ea	$ 1,166	$ 15,158
Bores	2.2.3	Existing Street, manicured naturestrips - All HDD / Boring Required	720	m	$ 180	$ 129,600
Bitumen Reinstatement	2.2.5	25% of works (180m x 0.5m trench width)	90	sqm	$ 143	$ 12,870
Reinstatement works	2.2.6	Established area, top soil , seed and install warning signs	720	m	$ 18	$ 12,960
Provings		Prove location of other utility assets - every 50m	15	ea	$ 465	$ 6,980
Others	**2.3**	Tie In / Air pressure test	2	ea	$ 824	$ 1,648.00
						$ -
						$ -
Sub-total - Construction						**$ 179,216**
Specialist Services	**3**					
Environmental & CH	**3.1**					
Reports	3.1.1	Site assessments etc		ea		$ 7,716
Cultural Heritage review	3.1.2	Site assessments etc		ea		$ 36,605.00
Survey	3.2.2	Title Boundary survey	1	ea	$ 900	$ 900.00
						$ -
Sub-total - Specialist Services						**$ 45,221**
						$ -
Sub-total - Other						**$ -**
PROJECT TOTAL						**$ 247,765**

Table C.4: Cost Estimate, Clyde North

		Capital Projects - Project Cost Estimate				
Project		Cranbourne East / Clyde NTh AA Cost Est 2019				
Prepared by		C Taberner				
Date		17.6.16				
Revision						
Scope of works		Install 500m x 180PE @ 515KPA in Cranbourne East / Clyde Nth from the proposed 180mm P7 in Berwick-Cranbourne Rd, south along Berwick-Cranbourne Rd to tie in to the existing 63P7 main in Salerno Way				
		Air Pressure Test - 2 sections				
	Item	**Description**	**No Units**	**Units**	**Cost / Unit**	**Total Cost**
Materials	**1**					
Line pipe	1.1	Pipe Plastic DN 180, 12M LG Series 2 PE 100	504	m	$ 27	$ 13,608
Bends, Fittings, Tees etc	1.4	From Materials tab, or factored from pipe & valves				$ 2,721
						$ -
Sub-total - Materials						**$ 16,329**
Construction	**2**					
Standard Contractor Items	**2.2**					
Single trench excavation	2.2.1			m		
Traffic Management	2.2.2	9 days traffic control required	9	ea	$ 1,166	$ 10,494
Bores	2.2.3	All Direct Drill - Boring, Limited space in road reserve - high traffic	500	m	$ 180	$ 90,000
Bitumen Reinstatement	2.2.5	25% of works (125m x 0.5m trench width)	62.5	sqm	$ 143	$ 8,938
Reinstatement Works	2.2.6	Established area, top soil, seed and install marker signs	500	m	$ 18	$ 9,000
Proving works		Prove other utility assets for alignment - every 50m	10	ea	$ 465	$ 4,653
Others	**2.3**	Tie In / Air pressure test	2	ea	$ 824	$ 1,648.00
						$ -
						$ -
Sub-total - Construction						**$ 124,733**
Specialist Services	**3**					
Environmental & CH	**3.1**					
Reports	3.1.1	Site assessments etc		ea		$ 7,716
Cultural Heritage review	3.1.2	Site assessments etc		ea		$ 36,605.00
Survey	3.2.2	Title Boundary survey works	1	ea	$ 900	$ 900.00
						$ -
Sub-total - Specialist Services						**$ 45,221**
PROJECT TOTAL						**$ 186,283**

Table C.5: Cost Estimate – Langwarrin (PE)

		Capital Projects - Project Cost Estimate				
Project		Langwarrin AA Cost Est 2020				
Prepared by		C Taberner				
Date		17.6.16				
Revision						
Scope of works		Install 900m x 125PE & 24m x 150mm ST @ 515KPA in Kelvin Grove Langwarrin Sth from the existing 180mm P7 in Cranbourne Rd to the proposed 300mm ST corner of McKays Rd. Also install 125mm PE isolation valve				
		Hydro				

	Item	Description	No Units	Units	Cost / Unit	Total Cost
Materials	**1**					
Line pipe	1.1	Pipe Plastic DN 125, 12M LG Series 2 PE 100	900	m	$ 13	$ 11,700
Line Pipe	1.2	Pipe Steel 168.3MM OD Trilaminte Coat 12M Lengths	24	ea	$ 52	$ 1,248
Bends, Fittings, Tees etc	1.4	From Materials tab, or factored from pipe & valves				$ 2,590
Others	1.8	150mm Steel line valve				$ 257
Pipe delivery					$ 1,800	$ 1,800
						$ -
Sub-total - Materials						**$ 17,595**
Construction	**2**					
Standard Contractor Items	**2.2**					
Single trench excavation	2.2.1	Open Cut 150mm Steel ,weld pipe fabricate and Install	24	m	$ 473	$ 11,352
Traffic Management	2.2.2	22 days traffic control required	22	ea	$ 1,161	$ 25,542
Boring	2.2.3	HDD all PE (900m) Road reserve heavily treed	900	m	$ 140	$ 126,000
T D Williamson	2.2.4	TDW Tapping - 150mm WT welded onto exisitng 300ST main	1	ea	$ 9,862	$ 9,862
Bitumen Reinstatement	2.2.5	Repair bitumen and road shoulder 25% works (231m x.05m trench width)	115.5	sqm	$ 143	$ 16,517
Reinstatement works	2.2.6	Top soil, seed and install pipe line marker posts	924	m	$ 18	$ 16,632
NDT	2.2.7	10% of welds , plus bores and bends	2	ea	$ 1,053	$ 2,106
Hydro Test	2.2.8	Pig / Hyrdro test / Water supply and disposal	1	ea	$ 24,517	$ 24,517
Proving works		Prove location of other utility assets - every 50m	19	ea	$ 465	$ 8,841
Others	**2.3**	Tie In Comdain	1	ea	$ 824	$ 824.00
						$ -
						$ -
Sub-total - Construction						**$ 242,193**
Specialist Services	**3**					
Environmental & CH	**3.1**					
Reports	3.1.1	Site assessments etc		ea		$ 7,716
Cultural Heritage review	3.1.2	Site assessments etc		ea		$ 36,605.00
Survey	3.2.2	Description	1	ea	$ 500	$ 500.00
Sub-total - Specialist Services						**$ 44,821**
						$ -
PROJECT TOTAL						**$ 304,609**

Table C.6: Cost Estimate - Langwarrin/Cranbourne South (Steel)

	Item	Description	No Units	Units	Cost / Unit	Total Cost
		Capital Projects - Project Cost Estimate				
Project		Langwarrin Nth AA Cost Est				
Prepared by		C Taberner				
Date		17.6.16				
Revision						
Scope of works		Install 3000m x 300mm ST @ 515KPA in McKays Rd Langwarrin. Connect from the existing 125PE in Kevlin Grove, travel east along McKays Rd , Browns Rd, then north along Pearcedale Rd connecting to the existing 125mm P7 in Pearcedale Rd. A secondary connection would be Cassinia Close				
		Hydro Test				
	Item	**Description**	**No Units**	**Units**	**Cost / Unit**	**Total Cost**
Materials	**1**					
Line pipe	1.1	PIPE,METALLIC:323.9MM OD,ERW,9.53MM WALL THK,12M LG,STL,3.275MM THK TRILAMINATE COATED,API 5L GR X42	3000	m	$ 128	$ 384,870
Bends, Fittings, Tees etc	1.4	From Materials tab, or factored from pipe & valves				$ 76,974
Others	1.8	Pipe Delivery	4		$ 1,800	$ 7,200
Sub-total - Materials						**$ 469,044**
Construction	**2**					
Standard Contractor Items	**2.2**					
Single trench excavation	2.2.1	Open Cut - 1m back of road shoulder (treed road reserve) 55% of works	1650	m	$ 562	$ 927,300
Traffic Management	2.2.2	83 days traffic control required	83	ea	$ 1,166	$ 96,778
Boring	2.2.3	Boring - HDD beneath trees 45% of works	1350	m	$ 753	$ 1,016,550
Boring in Rock	2.2.4	Boring in rock - allow 15% of works , Area known for rock ground conditions in Browns Rd /Pearcedale Rd Botanic Ridge	450	m	$ 800	$ 360,000
Bitumen Reinstatement	2.2.5	10% of works as majority of road is unsealed 300m x 0.5m	150	sqm	$ 143	$ 21,450
Final Reinstatement Works	2.2.6	Top soil, seed and install "warning" marker signs	3000	m	$ 18	$ 54,000
NDT	2.2.7	10% of welds , plus bores and bends	20	ea	$ 1,053	$ 21,060
Hydro Test	2.2.8	Pig / Hyrdro test / Water supply and disposal		ea		$ 118,911
Proving works		Prove other utility assets for proposed alignment -every 50m	60	ea	$ 465	$ 27,920
Others	**2.3**	Tie Ins x 2 - 300mm ST to existing 125mm PE	2	ea	$ 824	$ 1,648.00
						$ -
						$ -
Sub-total - Construction						**$ 2,645,617**
Specialist Services	**3**					
Environmental & CH	**3.1**					
Reports	3.1.1	Site assessments etc		ea		$ 7,716
Cultural Heritage review	3.1.2	Site assessments etc		ea		$ 36,605.00
Survey	3.2.2	Basic Survey works @ $900 per 1km	3	ea	$ 900	$ 2,700.00
Sub-total - Specialist Services						**$ 47,021**
PROJECT TOTAL						**$ 3,161,682**

Total cost to be spread over 2020 and 2021 as follows:

Langwarrin/Cranbourne South (Steel) $,000 2016			
	2020	2021	Total
Materials	469	0	469
Construction	1,000	1,646	2,646
Specialist Services	47	0	47
Total	1,516	1,646	3,162

Table C.8: Cost Estimate - Cranbourne North, Soldiers Road

	Item	Description	No Units	Units	Cost / Unit	Total Cost
		Capital Projects - Project Cost Estimate				
Project		Soldiers Rd Clyde Nth				
Prepared by		C Taberner				
Date		28.11.16				
Revision						
Scope of works		Install 1100m x 300mm ST @ 515KPA in Soldiers Rd Clyde Nth Hydro Test				
	Item	**Description**	**No Units**	**Units**	**Cost / Unit**	**Total Cost**
Materials	**1**					
Line pipe	1.1	PIPE,METALLIC:323.9MM OD,ERW,9.53MM WALL THK,12M LG,STL,3.275MM THK TRILAMINATE COATED,API 5L GR X42	1104	m	$ 128	$ 141,312
Valves	1.2	Major valves - from Materials tab		ea		$ -
Regulators	1.3	Major regulator equipment - from Materials tab		ea		$ -
Bends, Fittings, Tees etc	1.4	From Materials tab, or factored from pipe & valves				$ 28,263
E/I Materials	1.5	From Materials tab - show key items				$ -
CP materials	1.6	From Materials tab - show key items				$ -
Fabricated items	1.7	1 line for each - from Materials tab Includes pipe spools, skids, E/I panels etc etc		ea		$ -
Others	1.8	Pipe Delivery	2		$ 1,800	$ 3,600
						$ -
						$ -
Sub-total - Materials						**$ 173,175**
Construction	**2**					
Labour & Equipment	**2.1**					
APA Labour	2.1.1	Description of general APA labour - 1 line for each category or major activity - includes fitters, techs, construction crews, E/I and SCADA etc		hr		$ -
APA Labour	2.1.2	APA site supervision		hr		$ -
Contractor Labour	2.1.3	Description of general contractor labour - 1 line for each category or major activity Includes Comdain labour, welders etc etc		hr		$ -
Contractor Equipment	2.1.4	Description of general Comdain Equipment rates - excavators, trucks, small equipment etc - 1 line for each		hr		$ -
Commissioning Labour	2.1.5	Description of general APA & contractor labour for commissioning - 1 line for each of APA and Contractor				$ -
Standard Contractor Items	**2.2**					
Single trench excavation	2.2.1	Open Cut -	880	m	$ 562	$ 494,560
Traffic Management	2.2.2	30 days traffic control required	30	ea	$ 1,166	$ 34,980
Boring	2.2.3	Boring - HDD beneath trees 20% of works	220	m	$ 753	$ 165,660
Boring in Rock	2.2.4	Boring in rock - allow 20% of works ,	250	m	$ 800	$ 200,000
Bitumen Reinstatement	2.2.5	10% of works	110	sqm	$ 143	$ 15,730
Final Reinstatement Works	2.2.6	Top soil, seed and install "warning" marker signs	1100	m	$ 18	$ 19,800
NDT	2.2.7	10% of welds , plus bores and bends	10	ea	$ 1,053	$ 10,530
Hydro Test	2.2.8	Pig / Hyrdro test / Water supply and disposal		ea		$ 118,911
Proving works		Prove other utility assets for proposed alignment -every 50m	23	ea	$ 465	$ 10,695
Others	**2.3**	Tie Ins x 1 - 300mm ST to existing 180mm PE	1	ea	$ 1,460	$ 1,460.00
		City Gate Tie In 300mm ST # City Gate	1	ea	$ 9,000	$ 9,000
						$ -
Sub-total - Construction						**$ 1,081,326**
Specialist Services	**3**					
Environmental & CH	**3.1**					
Reports	3.1.1	Site assessments etc		ea		$ 7,716
Cultural Heritage review	3.1.2	Site assessments etc		ea		$ 36,605.00
Others	3.1.3	As applicable				$ -
						$ -
Others	**3.2**					$ -
Geotechnical assessment	3.2.1	Description		ea		$ -
Survey	3.2.2	Basic Survey works @ $900 per 1km	2	ea	$ 900	$ 1,800.00
Others	3.2.3	Description		ea		$ -
Underground locations	3.2.4	Description		ea		$ -
						$ -
Sub-total - Specialist Services						**$ 46,121**
Project Management and Design	**4**					
Labour	**4.1**					
Consultant Services, Fees & Approvals	**4.2**					$ -
Sub-total - PM and Design						**$ -**
Other	**5**	Insert other items as applicable				
Sub-total - Other						**$ -**
PROJECT TOTAL						**$ 1,300,622**

Table C.9: Cost Estimate - Cranbourne North, Berwick – Cranbourne Road

		Capital Projects - Project Cost Estimate				
Project		Berwick Cranbourne Rd Clyde Nth				
Prepared by		C Taberner				
Date		6.12.16				
Revision						
Scope of works		Install 400m x 180mm PE @ 515KPA in Berwick Cranbourne Rd from Arbourlea Bvd to Blooms Estate (Fenway Bvd)				
		Air pressure test in 1 section				
	Item	**Description**	**No Units**	**Units**	**Cost / Unit**	**Total Cost**
Materials	**1**					
Line pipe	1.1	Pipe, Plastic:DN 180, 12M LG Series 2 PE 100	400	m	$ 27	$ 10,844
Valves	1.2	Major valves - from Materials tab		ea		$ -
Regulators	1.3	Major regulator equipment - from Materials tab		ea		$ -
Bends, Fittings, Tees etc	1.4	From Materials tab, or factored from pipe & valves				$ 2,168
E/I Materials	1.5	From Materials tab - show key items				$ -
CP materials	1.6	From Materials tab - show key items				$ -
Fabricated items	1.7	1 line for each - from Materials tab Includes pipe spools, skids, E/I panels etc etc		ea		$ -
Others	1.8	Others from Materials tab				$ -
						$ -
						$ -
Sub-total - Materials						**$ 13,012**
Construction	**2**					
Labour & Equipment	**2.1**					
APA Labour	2.1.1	Description of general APA labour - 1 line for each category or major activity - includes fitters, techs, construction crews, E/I and SCADA etc		hr		$ -
APA Labour	2.1.2	APA site supervision		hr		$ -
Contractor Labour	2.1.3	Description of general contractor labour - 1 line for each category or major activity Includes Comdain labour, welders etc etc		hr		$ -
Contractor Equipment	2.1.4	Description of general Comdain Equipment rates - excavators, trucks, small equipment etc - 1 line for each		hr		$ -
Commissioning Labour	2.1.5	Description of general APA & contractor labour for commissioning - 1 line for each of APA and Contractor				$ -
Standard Contractor Items	**2.2**					
Single trench excavation	2.2.1	All Direct drill (limited space in road reserve, open cut restricted)	400	m	$ 173	$ 69,200
Traffic Management	2.2.2	8 days traffic control required	8	ea	$ 1,166	$ 9,328
Bores	2.2.3	1 line for each type Includes thrust bores and HDD		ea		$ -
T D Williamson	2.2.4	Description		ea		$ -
Bitumen cutting	2.2.5	Description				$ -
Bitumen Reinstatement	2.2.6	Description		ea		$ -
Bore in Rock	2.2.7	Bore in rock (extra over) 10% of works	40	ea	$ 800	$ 32,000
Hydro Test	2.2.8	Description		ea		$ -
		Proving other utlilty assets	8	ea	$ 465	$ 3,720
Others	**2.3**	Tie In / Air pressure test	2	each	$ 1,460	$ 2,920.00
						$ -
						$ -
Sub-total - Construction						**$ 117,168**
Specialist Services	**3**					
Environmental & CH	**3.1**					
Reports	3.1.1	Basic Cultural Heritage Management Plan		ea		$ 7,716
Cultural Heritage review	3.1.2	Site assessments etc		ea		$ 36,605.00
Others	3.1.3	As applicable				$ -
						$ -
Others	**3.2**					$ -
Geotechnical assessment	3.2.1	Description		ea		$ -
Survey	3.2.2	Description	1	ea	$ 900	$ 900.00
Others	3.2.3	Description		ea		$ -
Underground locations	3.2.4	Description		ea		$ -
						$ -
Sub-total - Specialist Services						**$ 45,221**
Project Management and Design	**4**					
Labour	**4.1**					
Consultant Services, Fees & Approvals	**4.2**					$ -
Sub-total - PM and Design						**$ -**
Other	**5**	Insert other items as applicable				
Sub-total - Other						**$ -**
PROJECT TOTAL						**$ 175,401**

Table C.8: Cost Estimate, Cranbourne East/Cranbourne North

		Capital Projects - Project Cost Estimate				
Project		Clyde NTh AA Cost Est 2022				
Prepared by		C Taberner				
Date		17.6.16				
Revision						
Scope of works		Install 1656m x 180PE and 24m x 200mm ST@ 515KPA in Clyde Nth , Construct in Hardys Rd, from the proposed 200ST crn Tuckers Rd (that will service the City Gate), travel west along Hardys Rd to connect into the proposed 180mm PE in Berwick Cranbourne Rd				
		Hydro Test				

	Item	**Description**	**No Units**	**Units**	**Cost / Unit**	**Total Cost**
Materials	**1**					
Line pipe	1.1	Pipe Plastic DN 180, 12M LG Series 2 PE 100	1656	m	$ 27	$ 44,712
Line Pipe	1.2	Pipe Metallic Steel 219.1MM Trilaminate	24	ea	$ 73	$ 1,752
Bends, Fittings, Tees etc	1.4	From Materials tab, or factored from pipe & valves				$ 9,292
Others	1.8	Pipe Delivery	1	ea	$ 1,800	$ 1,800
Sub-total - Materials						**$ 57,556**
Construction	**2**					
Standard Contractor Items	**2.2**					
Single trench excavation	2.2.1	open cut 30% works	504	m	$ 180	$ 90,720
Traffic Management	2.2.2	35 days traffic control required	35	ea	$ 1,166	$ 40,810
Bores	2.2.3	HDD 70% of works (treed road reserve)	1152	m	$ 180	$ 207,360
Single trench excavation		Open cut 24m for 200mm Steel pipe	24	m	$ 504	$ 12,096
T D Williamson	2.2.4	TDW Tapping from proposed 200ST in Tuckers Rd	1	ea	$ 9,862	$ 9,862
Bitumen Reinstatement	2.2.5	25% works (road to be sealed in the future) 420m x 0.5m width	210	sqm	$ 143	$ 30,030
Final Reinstatement works	2.2.6	Top Soil, seed and install warning sign marker posts	1680	m	$ 18	$ 30,240
NDT	2.2.7	10% of welds , plus bores and bends	3	ea	$ 1,053	$ 3,159
Hydro Test	2.2.8	Pig / Hyrdro test / Water supply and disposal		ea		$ 24,517
Proving works		Prove other utility assets for alignment - every 50m	34	ea	$ 465	$ 15,822
Others	**2.3**	Tie In - Comdain	1	ea	$ 824	$ 824.00
						$ -
						$ -
Sub-total - Construction						**$ 465,440**
Specialist Services	**3**					
Environmental & CH	**3.1**					
Reports	3.1.1	Site assessments etc		ea		$ 7,716
Cultural Heritage review	3.1.2	Site assessments etc		ea		$ 36,605.00
Survey	3.2.2	Title boundary survey works	1	ea	$ 900	$ 900.00
						$ -
Sub-total - Specialist Services						**$ 45,221**
PROJECT TOTAL						**$ 568,217**

Table C.9: Cost Estimate, Clyde North - Soldiers Rd (Gate Station)

	Item	Description	No Units	Units	Cost / Unit	Total Cost
Materials	**1**					
Monolithic Insulation Joints	1.1					$ 16,590
Regulators	1.2					$ 63,276
Pilot regulators	1.3					$ 6,000
Valves	1.4					$ 64,287
Filters	1.5					$ 10,390
SCADA	1.6					$ 25,000
Hot Water Boiler Heater	1.7					$ 222,400
Heater UPS System	1.8					$ 10,000
Sub-total - Materials						**$ 417,943**
Construction	**2**					
Standard Contractor Items						
Purchase of Pipe						$ 7,175.92
Bend,elbow, reducer, flange etc						$ 5,390.00
Stopple, baghole, TOR						$ -
Slam shut Panel						$ 9,000.00
Shed and skid						$ 38,500.00
Project Management (contractor)						$ 79,829.00
Work Shop and Prefabrication						$104,940.00
Site Work						$246,658.00
Commissioning Support						$ 13,408.00
Fencing						$ 94,739.00
Landscaping						$ 25,000.00
Tubing						$ 3,975.00
Excavation Conduits						$ 3,000.00
Excavation						$ 20,000.00
Slabs						$ 35,000.00
Tree Removal						$ 24,100.00
Bunding / Drainage						$ 15,000.00
Crushed rock						$ 15,000.00
Electrical supply and chemical drainage						$ 85,000.00
Other anciliary Civil Works						$ 65,000.00
Extra motor, 2nd gas run						$ 17,000.00
SCADA						
Installation						$15,000.00
Design and Drawing						
Noise Investigation						$9,295.00
Pipe Stress Analysis						$ 5,700
Slab Design						$ 14,900
Survey						$ 1,100.00
Geotech for slab design						$ 3,654
Sub-total - Construction						**$ 957,364**
Specialist Services	**3**					
Environmental & CH	**3.1**					
Soil Assessment	3.1.1			ea		$4,090.00
Cultural Heritage review	3.1.2			ea		$36,605.00
Construction Environmental Management Plan	3.2.2			ea		$16,307.00
						$ -
Sub-total - Specialist Services						**$ 57,002**
						$ -
Sub-total - Other						**$ -**
PROJECT TOTAL						**$ 1,432,309**

Business Case – Capex V54

Dandenong to Crib Point Pipeline – Refurbishment

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	Matthew Read, *Integrity Engineer*
Approved By	Andrew Foley, *General Manager Victorian Networks*

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	The Dandenong to Crib Point pipeline (DCP) was originally constructed in 1966 to supply refinery gas from the BP Crib Point refinery to Dandenong. It was subsequently converted to carry natural gas from Dandenong to Crib Point and now supplies over 100,000 customers on the Mornington Peninsula. In the current Access Arrangement (AA) review, the AER approved an allowance of $6,341 ($000, real 2011) for Australian Gas Networks Limited (AGN) to establish the baseline condition and carry out a refurbishment program to maintain the ongoing integrity of the 39 kilometres DCP.[1] While a significant portion of this program is expected to be completed by the end of the current (2013 to 2017) AA period, AGN decided to defer the installation of facilities to enable in-line inspections (ILI) to be carried out on the DCP, the ILI associated repair and data validation works, and the refurbishment of the last Cathodic Protection Unit (CPU) anode bed until the next (2018 to 2022) AA period. AGN decided to defer the installation of ILI facilities and the associated repair and data validation works because of the risks associated with the ILI becoming lodged in part of the pipeline upstream of where the current pipeline duplication commences, which could affect supply to over 100,000 customers. Rather than installing the facilities and later moving them, AGN decided to defer the investment until the proposed duplication of 3.4km of the DCP upstream of where it currently commences is completed in the next AA period (see Business Case V23 of this submission for the next AA period). As to the CPU anode bed, AGN decided to defer the refurbishment because unlike the other two units that were identified in the original business case, it has only recently shown signs of decreased performance. Once a CPU starts to show signs of decreased performance (protection levels on the pipeline decrease), there are certain adjustments that can be made to restore protection levels to the required values. However, if the performance continues to decline (i.e. the CPU is reaching the end of its life), a point is reached where adjustments can no longer be made, and the pipeline may not be adequately protected from corrosion.
Options Considered	The following options have been considered to deal with the three refurbishment items that were approved by the AER in the last AA period but have not yet been undertaken:

[1] The business case that the AER approved was V04 Refurbishment of Dandenong to Crib Point Pipeline. See AER, *Access Arrangement Final Decision Envestra Ltd, Part 2 Attachments*, March 2013, pg. 94.

	• *Option 1:* Do nothing. • *Option 2:* Refurbish the final CPU anode bed, locate the inspection tool launcher at Dandenong and the receiver at Crib Point and conduct an ILI following the DCP duplication (V23). • *Option 3:* Refurbish the final CPU anode bed and locate the inspection tool launcher at Abbotts Road, Dandenong South and receiver at Crib Point and conduct an ILI. Once the DCP duplication (V23) is complete, relocate the inspection tool launcher to Dandenong and conduct another ILI. • *Option 4:* Refurbish the final CPU anode bed and recoat all accessible sections of the pipeline.
Proposed Solution	Option 2 has been selected because it is the most cost effective way to reduce the risk associated with corrosion and deterioration of pipelines and achieves a reasonable balance between residual risk and cost.
Estimated Cost	Option 2 is forecast to cost $2,242 ($000, 2016), of which $1,652 ($000, 2016) is capital expenditure (capex) and $590 ($000, 2016) is operating expenditure (opex).
Opex Step Change	The opex of $590 ($000, 2016) does not require a step change in base year opex, as it replaces the excavations due to Direct Current Voltage Gradient (DCVG) surveys on these pipelines.
Consistency with the National Gas Rules (NGR)	The capex component of this option complies with the new capital expenditure criteria in rule 79 of the National Gas Rules (NGR) because: • 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)); and • it is justifiable under 79(2)(c) because it is required to maintain and improve the safety of services (rule 79(2)(c)(i)), maintain the integrity of services (rule 79(2)(c)(ii)) and maintain AGN's capacity to meet existing levels of demand for services existing at the time the capex is incurred (rule 79(2)(c)(iv)). The opex component also satisfies rule 94 because 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.
Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Reliability theme as its implementation will allow AGN to continue providing a highly reliable supply of natural gas to AGN's customers by modifying the DCP to undertake ILI and refurbishing the final CPU anode bed. More information detailing the results of AGN's stakeholder engagement program is provided in Chapter 5 of the Access Arrangement Information (Final Plan, AAI) document.
Supporting Information	• Supporting Information 1: V04 Refurbishment of Dandenong to Crib Point Pipeline - Envestra Business Case (AA 2013-17) • Supporting Information 2: NPV and Options Analysis

1.3. Background

The DCP was originally constructed in 1966 to supply refinery gas from the BP Crib Point refinery to Dandenong. It was subsequently converted to carry natural gas from Dandenong to Crib Point and now supplies over 100,000 consumers on the Mornington Peninsula, representing approximately 20% of AGN's Victorian annual demand. A summary of technical details for the pipeline is provided in Appendix A.

A significant portion of the DCP alignment is in a rural / park reserve setting located in easements with up to five other oil and gas pipelines in close vicinity, including the duplication of the DCP between Dandenong South and Langwarrin (16.7 kilometres). Should there be an incident on any one pipeline, it has the potential to cause collateral damage to one or more of the other pipelines located in the easements.

It is also planned to continue the duplication for 3.4 kilometres upstream of where it currently commences during the next AA period, to the beginning of the pipeline, resulting in 20.1 kilometres of the 39 kilometre pipeline being duplicated. The corresponding business case number for these works is V23.

The risk profile of the DCP has changed since it was originally constructed; with industrial encroachment upstream of the duplication resulting in development of industrial land within the measurement length of the pipeline (refer to Appendix D for a description of the measurement length) in the north, and urban encroachment around the Hastings township in the south. This has resulted in sections of the DCP, such as where the pipeline is located underneath road pavement or concrete, which have restricted access for coating inspection and subsequent direct assessment and repair.

The DCP was designed and built to a superseded revision of American standard USAS B.31.8 and is approaching two-thirds of its 80 year design life. There are limited construction records available making it difficult to assess the quality of construction. A number of construction issues have been discovered on the pipeline, such as inadequate backfill and poor coating adhesion due to high longitudinal weld seam reinforcement, resulting in a large number of severe coating defects. While the Cathodic Protection (CP) system should prevent corrosion from occurring as the coating continues to degrade, inspection of the pipeline steel condition is required to confirm this.

The current configuration of the DCP is unable to accommodate an intelligent ILI tool. This is due to the original vintage inspection tool traps not being sized appropriately for modern tools, and so inspection of the pipeline steel condition can only be carried out by direct examination at coating faults identified via a DCVG survey conducted from the surface. While direct examination by excavating and removing the coating to examine the pipeline steel will confirm with a high level of accuracy if there is any corrosion or anomalies in the area exposed, this only provides a small sample of the entire pipeline length and only for anomalies which are associated with coating disbondment. Furthermore, factors such as soil type or defect shape may impact accuracy of measurements and lead to a lower probability of detecting faults. There are also sections of the pipeline, such as under river or rail crossings and in some sections of road reserve, which cannot be inspected by this method. These types of sections account for approximately 5% to 10% of the DCP pipeline alignment.

A summary of recent coating surveys and subsequent excavations is provided in Table 1.3. APA policies, developed to ensure compliance with Australian Standards, require mandatory excavations to inspect the condition of the coating and underlying pipe steel when the voltage gradient measured at the ground surface by the DCVG survey is above a threshold value (greater than 15% IR drop[2]). Further, defects between 5% and 15% IR drop must be considered as a site that is a candidate for excavation, assessed using other factors described within the policy. The quantity of coating faults that require repair based on this indirect measurement is increasing as the pipeline ages, with repairs also revealing that replacement of more coating than in previous

2 IR Drop (equivalent to voltage drop) is a measure of the voltage gradient measured at the ground surface associated with a coating defect on the buried steel pipeline.

years is required (sometimes greater than 20 metres length of coating). It should be noted that the information in this table does not include sections of the pipeline which are inaccessible for inspection, which represent approximately 5% to 10% of the pipeline's length.

Table 1.4: Summary of Coating Surveys

Coating Survey Year	Coating Faults Detected	Coating Faults Requiring Repair	Comments
1999	90	13	No corrosion identified.
2009	667	27	Seven instances of corrosion or manufacturing anomalies detected; none which warranted further action.
2013	346	52	One mill / manufacturing anomaly detected which did not require further action from 18 excavations undertaken so far from this survey.

This table shows that while there are an increasing number of coating anomalies being detected (i.e. the coating is degrading more quickly over time), there is not, for the sites excavated, an emerging corrosion problem. However this conclusion is restricted to only the sites examined, and cannot necessarily be extrapolated to the whole pipeline.

Corrosion events have been detected on the DCP, with these events initiating prior to 2009. It is extremely difficult to determine the rate of growth for corrosion, particularly in the absence of the comprehensive data that can be obtained from ILI. The corrosion growth rate is dependent on a number of localised factors such as soil type and CP levels. These factors are subject to a range of uncertainty and may vary greatly along the length of a pipeline. If an industry standard corrosion growth rate of 0.4mm/year is applied to corrosion events detected from coating faults identified in 2009, it is possible that they may reach failure point within 14 years (i.e. 2023). Given that the number of coating faults and potential corrosion sites is increasing, there is an increased probability that one of these sites will develop into a leak.

Inspection using an intelligent ILI tool will detect a much larger sample of corrosion or anomalies along the pipeline length. This inspection method indirectly examines the pipeline steel and provides far more comprehensive and accurate data than can be obtained from coating fault surveys. ILI can also be used to inspect a greater proportion of the pipeline length, including areas which have restricted access for direct examination, and can identify anomalies which may not be associated with coating faults (for example third party generated dents). The data from an ILI tool can be used to generate a targeted repair program and provide a baseline condition for a pipeline, which may be used as data for an assessment of an extension of the pipeline life. By conducting an ILI on the DCP, there is a high probability of detecting features which may develop into a significant integrity threat, and a repair program can be conducted based on indirect measurements of the condition of the pipeline steel rather than the coating.

ILI is considered good industry practice for demonstrating pipeline structural integrity, with the APA ILI policy requiring that all new pipelines greater than or equal to DN150 be designed to accommodate ILI tools. Other pipeline operators have modified existing pipelines to be inspected by ILI where they were not originally constructed for these tools. The latest revision to Australian Standard (AS) 2885.3-2012 (Clause 6.6) requires that consideration be given to modifying pipelines to permit inspection by ILI when it is not capable of accommodating an ILI tool.

1.3.1. Current Access Arrangement Period Refurbishment Works

In the last AA review, the AER approved an allowance of $6,341 ($000, 2011) for AGN to establish the baseline condition and carry out a refurbishment program to maintain the ongoing integrity of the 39 kilometre DCP (refer to Business Case V04 in Supporting Information 1),[3] which included:

1 Engineering investigation and pipeline alterations to enable ILI.

2 ILI of the pipeline and subsequent repairs or validations.

3 Other pipeline refurbishment works including:

   a removal of remnant vegetation from the pipeline alignment;

   b decommissioning of a suspended pipeline section;

   c line valve reconditioning;

   d creek cover remediation;

   e refurbish and upgrade of three Cathodic Protection Units (CPU); and

   f repair pipeline coating faults.

AGN has commenced these refurbishment works during the current AA period with the first item being the engineering investigation to finalise the scope for the program, as the works proposed in Business Case V04 were general in nature and based on information available prior to the current AA period. It was determined during the engineering investigation that three of the refurbishment items listed above should be deferred to the next AA period. These items are discussed in further detail in Section 1.3.1.2. This investigation further defined the scope of works required for the pipeline and developed a more precise cost estimate. Some works were found to not be required due to advancements in ILI tool technology (replacement of an offtake with inspection tool guide bars was not required), and so the final cost estimate for the total refurbishment program was approximately 60% of the original estimate.

Total costs accrued for the refurbishment program to March 2016 are $365.5 ($000, 2016), with an additional $1,765.3 ($000, 2016) planned to be spent prior to the next AA period. All the refurbishment items undertaken to date have successfully addressed the integrity issue they were intended to rectify. A summary of the anticipated costs and progress during the current AA period for each aspect of the refurbishment program is presented in Table 1.4.

[3] See AER, *Access Arrangement Final Decision Envestra Ltd, Part 2 Attachments*, March 2013, p. 94.

Table 1.4: DCP Refurbishment Cost and Progress for Current AA Period

Item	Refurbishment Item	Anticipated Cost in Current AA Period ($000 real $2016)	Anticipated Progress During Current AA Period
1	Engineering investigation and pipeline alterations to enable ILI	237.6	Engineering investigation, valve and offtake investigation and filter replacement expected to be completed in current AA.
2	ILI of the pipeline and subsequent repairs or validations	-	ILI and subsequent repairs deferred to next AA period.
3a	Removal of remnant vegetation from the pipeline alignment	243.9	All associated works expected to be complete during current AA period.
3b	Decommissioning of suspended pipeline section	665.0	All associated works expected to be complete during current AA period.
3c	Line valve reconditioning	117.7	All associated works expected to be complete during current AA period.
3d	Creek cover remediation	166.2	All associated works expected to be complete during current AA period.
3e	Refurbish and upgrade of three Cathodic Protection Units (CPU)	139.4	Two CPU's expected to be refurbished during current AA period. Final CPU refurbishment deferred.
3f	Repair pipeline coating faults	561.0	All associated works expected to be complete during current AA period.
	Total	**2,130.8**	

1.3.1.1. Refurbishment Works Deferred to Next Access Arrangement Period

There are three refurbishment items expected to continue beyond the current AA period, and are the subject of this Business Case. These items include refurbishment of the final CPU, pipeline alterations to allow for ILI and ILI of the pipeline with subsequent repairs or validations.

Refurbishment of the Final CPU

Refurbishment of the final CPU anode bed has been deferred to the next AA period because unlike the other CPUs on the pipeline, the final CPU has only recently showed signs of decreased performance and a requirement for replacement. Once a CPU starts to show signs of decreased performance (protection levels on the pipeline decrease), there are certain adjustments that can be made to restore protection levels to the required values. However, if the performance continues to decrease (ie the CPU is reaching the end of its life), a point is reached where adjustments can no longer be made, and the pipeline may not be adequately protected from corrosion.

Alterations to Allow ILI Runs

Risk assessments were conducted at various stages of the engineering investigation to assist with determining appropriate pipeline alteration to allow for ILI. In particular, the threat to supply from an ILI tool becoming lodged in the pipeline was evaluated in detail. It was determined during the risk assessment that there is a significant residual risk associated with ILI of the section of the pipeline upstream of where the current pipeline duplication commences. If an ILI tool was to become lodged in this section it could threaten supply to most customers supplied by the pipeline, whereas downstream of the duplication significantly less customers would be affected.

It was determined during the engineering assessment that replacement of the inspection tool launcher at the start of the pipeline and inspection tool receiver at Crib Point is required. However, the present location of the inspection tool launcher is 3.4km upstream of the current duplication at the start of the DCP and so the integrity of the pipeline in this 3.4km would be subject to the residual risk described above. Two options were considered during the engineering assessment for mitigating this risk, with further details provided in Section 1.5:

- install an inspection tool launcher at the commencement of the current duplication and conduct an ILI run. Once the final duplication is complete (see Business Case V23) relocate the inspection tool launcher to the present location at the start of the pipeline and conduct an additional ILI run; or
- replace the inspection tool launcher at the present location at the start of the pipeline (part of the scope of point 1 in Section 1.3.1.1) and await final duplication of the DCP prior to conducting an ILI run.

In contrast to the first option, the second option only requires one ILI run to be conducted in the next AA period and was therefore deemed the most appropriate and cost effective solution. It was also considered suitable to delay capital expenditure associated with replacement of the inspection tool traps and so this was also deferred to the next AA period.

Due to the type of coating and the age of this pipeline it is becoming increasingly difficult to demonstrate that the structural integrity complies with the latest revision of AS 2885.3-2012 (Clause 6.5). In the absence of being able to conduct ILI on these pipelines, it is becoming increasingly reliant on coating fault excavations, which only provides a localised view of corrosion at any one point on the pipeline, and only a small statistical sample of the entire pipeline length. Corrosion events can be extremely localised, and in order to develop a broad understanding of corrosion along the whole of the pipelines, a larger number of samples than the coating fault excavations is required.

Throughout the stakeholder engagement process, feedback was provided that demonstrates stakeholders value initiatives that improve the safety and reliability of the AGN network. Consistent with the above insight, ensuring that corrosion on major transmission mains is minimised and that the integrity of these pipelines is assured contributes to the provision of a safe supply of natural gas and reduce the risk of outages.

1.4. Risk Assessment

The untreated risks associated with this project are summarised in Table 1.5. Further detail on the risk assessment is provided in Appendix B to this business case.

Table 1.5: Risk Rating

Risk Area	Untreated Risk Level
Health and Safety	Moderate
Environment	Low
Operational	High
Customers	High
Reputation	High
Compliance	Moderate
Financial	High
Untreated Risk Rating	**High**

This project's risk assessment has taken into account:

- risk to health and safety for residents and industries in close proximity to the pipeline alignment from the collection of natural gas from an unidentified leak and ignition; and
- operational risk of failure of supply to approximately 100,000 customers (including major industrial and commercial customers) in the area from a worst case failure event, such as a leak at the start of the pipeline.

The principal risk is related to a major failure of the pipeline as a result of corrosion caused by degradation of the CPU or deterioration of a pipeline defect which has not been identified by the indirect assessments or localised excavations to date. The stress levels for this pipeline are such that a propagating rupture is unlikely; however, a significant gas release could occur during failure. An emergency repair would require isolation of a pipeline section and depending on the location and time of year could result in major disruption of supply to over 100,000 industrial and residential consumers.

The location risk profile is changing from predominantly rural to an urbanised environment in the north and a semi urbanised environment in the south, such that failure of the pipeline could potentially impact the safety of residents and industries in close proximity. In the event of a significant failure of the DCP there is a risk of escalating consequential damage to third party and AGN pipelines in the close vicinity, resulting in a major emergency incident and widespread community disruption.

1.5. Options Considered

The following options have been identified to mitigate the risks associated with the current configuration of the DCP:

1. *Option 1:* Do nothing.
2. *Option 2:* Refurbish the third CPU anode bed and install ILI facilities (inspection tool launcher at Dandenong and receiver at Crib Point) and conduct an ILI following the DCP duplication (Business Case V23).

3 *Option 3:* Refurbish the third CPU anode bed and install ILI facilities (inspection tool launcher at Abbotts Road, Dandenong South and receiver at Crib Point) and conduct ILI. Relocate inspection tool launcher to Dandenong following pipeline duplication (Business Case V23) and conduct another ILI.

4 *Option 4:* Refurbish the final CPU anode bed and recoat all pipeline sections that are accessible.

With the exception of the do nothing option, all of these options involve the refurbishment of the final CPU. The main difference between options 2, 3 and 4 is whether ILI facilities are installed (options 2 and 3) or not (options 4) and in the case of options 2 and 3 whether the ILI facilities are installed and ILI conducted for most of the pipeline before or after the duplication under Business Case V23 is completed.

Hydrostatic testing of the pipeline was not considered as this option would require shut down and loss of all customers supplied by the pipeline.

1.5.1. Option 1 – Do Nothing

The first option that AGN has identified is to do nothing (i.e. not carry out the ILI and CPU anode bed refurbishment works that were approved by the AER in the current AA period). Under this option AGN would continue to inspect the pipeline by direct assessment based on coating fault results, and the performance of the final CPU would continue to degrade until CP levels are no longer sufficient to prevent corrosion. This will continue until either significant corrosion degradation is identified that requires reactive repair at much higher costs than planned works or a pipeline failure event occurs. Significant corrosion degradation or a failure event may also result in reduction of the pipeline’s life.

1.5.1.1. Cost/Benefit Analysis

The benefit of this option is that there are no upfront capital costs. There are, however, a number of costs under this option, including:

- Ongoing operational costs of the pipeline by means of coating inspection and subsequent excavations at a starting cost of $600 ($000, 2016), with costs escalating following each five yearly coating survey as the pipeline coating continues to deteriorate. These costs are initial costs estimated from the number of anticipated coating faults requiring excavation into the future (see below), and the estimated cost of coating fault excavations of $12,750 per site, from the recently approved South Australian business case for the same activity (SA21a). It is expected that an additional 25 coating faults will require repair following each five yearly coating survey, resulting in this cost increasing over time.
- Some sections of the pipeline will continue to remain inaccessible for inspection, such as under river or rail crossings and underneath some sections of road pavement or concrete.
- The cost of repairing a pipeline defect which reaches the point of leaking may be up to $250 ($000, 2016) more than a defect which is not leaking.
- A worst case failure event, such as a leak at the start of the pipeline, could result in loss of supply to approximately 100,000 customers, at a cost of $4,000 ($000, 2016) for relighting. Such an interruption could also result in AGN having to make Guaranteed Service Level (GSL) payments of $30,000 ($000, 2016), which is $300 per customer for a lengthy interruption, resulting in a total cost of $34,000 ($000, 2016).
- With limited means to demonstrate pipeline baseline integrity, once the end of pipeline life is reached it is likely that replacement will be required.

- No reduction in the risk ranking identified in Section 1.4 (i.e. the residual risk remains High).
- A cost benefit analysis has been completed for this option (see Section 1.6.2), which shows that over the next 30 years of the pipeline's operation the cost of this option in present value terms is $4,980 ($000, 2016).

1.5.2. Option 2 – Dandenong Inspection Tool Launcher

The second option AGN has identified involves locating an inspection tool launcher and receiver at Dandenong and Crib Point respectively, where there are connections to the pipeline available to tie in the infrastructure, and conduct an ILI run following the final duplication of the pipeline. While the launcher and receiver can be installed at any stage prior to the ILI run, the ILI run itself is dependent on completion of the duplication.

The proposed scope of works for this option is as follows:

- Replace final CPU anode bed.
- Land negotiation, approval and compensation for new inspection tool launcher and receiver locations.
- Design, procurement and fabrication of new inspection tool launcher and receiver.
- Regulatory approval.
- On-site construction.
- Cleaning and pre-inspection activities prior to ILI run.
- ILI run.
- Pipeline excavations for repair or validation of ILI results.

1.5.2.1. Cost/Benefit Analysis

The costs for this option consist of a total initial cost of $1,717 to $2,227 ($000, 2016) and ongoing costs of $635 to $715 ($000, 2016) likely every 10 years for ILI and subsequent repairs / verifications, and include the specific costs shown below:

- Installation of inspection tool traps and associated infrastructure DCP at a cost of $1,043 ($000, 2016).
- ILI run at a cost of $555 ($000, 2016). Reinspection frequencies are based on preceding results but are generally 10 year intervals, and will replace coating inspection and subsequent excavations.
- Repair or data validation based on initial ILI results at a cost between $80 and $590 ($000, 2016). The lower cost for this represents validation excavations where no further repair of the pipeline steel is required, while the higher cost includes an allowance for some minor and significant urgent repairs being required on the pipeline. Future repair or data validation would be expected to cost between $80 and $160 ($000, 2016), with the lower cost similar to the initial ILI results and the higher cost including an allowance for minor repair. This is because subsequent ILI runs will be conducted at a frequency which would identify corrosion anomalies before they required significant urgent or more significant repair.
- Replacement of the final CPU anode bed at a cost of $54 ($000, 2016).
- Longer exposure to the untreated risk while awaiting final duplication.

- A cost benefit analysis has been conducted on this option (see Section 1.6.2), which shows that over the next 30 years of the pipeline's operation the cost of this option in present value terms is $2,954 ($000, 2016).

The benefits for this option include:

- Inspection of entire pipeline with accurate location, nature and magnitude of pipeline steel deterioration.
- Reduction of residual risk for the pipeline to Moderate (refer to Appendix B for risk ranking) because this option significantly reduces the likelihood of a pipeline failure due to corrosion.
- Baseline data will be available for assessing extension of the pipeline life once the design life is reached.

1.5.3. Option 3 – Abbots Road Inspection Tool Launcher

The third option that AGN has identified involves locating an inspection tool launcher where the current duplication commences at Abbotts Road, Dandenong South, and replacing the inspection tool receiver at Crib Point. Installation of an inspection tool launcher at Abbotts Road will require a new inspection tool trap riser to be cut in as there is no existing connection available at this location, but there is a connection available at Crib Point. An initial ILI will be conducted between these two points and will not inspect the section upstream of the current duplication until the final duplication under Business Case V23 has occurred. Following completion of the final duplication, the inspection tool launcher will need to be relocated to the start of the pipeline at Dandenong and an additional ILI conducted. An overview of the inspection tool launcher locations is contained in Appendix A. This option also includes the replacement of the final CPU anode bed and will require an additional ILI run relative to Option 2.

This option allows for most of the pipeline to be inspected independently from the timing of the final duplication proposed in Business Case V23. It is expected that this option will be required if final duplication is deferred or unable to be delivered in the next AA period.

The proposed scope of works for this option in the next AA period is as follows:

- Replace final CPU anode bed.
- Land negotiation, approval and compensation for new inspection tool receiver location and initial inspection tool launcher location.
- Design, procurement and fabrication of new inspection tool launcher and receiver.
- Regulatory approval.
- On-site construction.
- Cleaning and pre-inspection activities prior to initial ILI run.
- Initial ILI run from Abbotts Road to Crib Point.
- Pipeline excavations for repair or validation of ILI results.

The proposed scope of works for this option in the subsequent (2023 to 2027) AA period is:

- Relocation of the inspection tool launcher to the start of the pipeline at Dandenong once the final duplication (Business Case V23) is complete.
- Cleaning and pre-inspection activities prior to second ILI run.
- Second ILI run of whole pipeline, DCP.

- Pipeline excavations for repair or validation of ILI results.

1.5.3.1. Cost/Benefit Analysis

The costs for this option in the next AA period consist of total initial cost of $2,097 to $2,447 ($000, 2016) and include the specific costs shown below:

- Installation of inspection tool traps and associated infrastructure at Abbotts Road and Crib Point at a cost of $1,450 ($000, 2016). This includes additional works at Abbotts Road to cut in a new inspection tool trap riser.
- Initial ILI run at a cost of $535 ($000, 2016) for a shorter length of the pipeline between Abbotts Road and Crib Point.
- Repair or data validation based on initial ILI results at a cost between $80 and $430 ($000, 2016). The lower cost for this represents validation excavations where no further repair of the pipeline steel is required, while the higher cost includes an allowance for some minor and significant urgent repairs being required for the pipeline.
- Replacement of the final CPU at a cost of $54 ($000, 2016).
- A cost benefit analysis of this option has been conducted (see Section 1.6.2), which shows that over the next 30 years of the pipeline's operation the cost of this option in present value terms is $3,918 ($000, 2016).

The costs for this option in the subsequent AA period consist of total initial cost of $935 to $1,015 ($000, 2016) and include the specific costs shown below:

- Relocating the inspection tool launcher from Abbotts Road to Dandenong at a cost of $300 ($000, real 2016).
- Second ILI run at a cost of $555 ($000, 2016). Reinspection frequencies are based on preceding results but are generally 10 year intervals, and will replace coating inspection and subsequent excavations.
- Repair or data validation based on initial ILI results at a cost between $80 and $160 ($000, 2016). The lower cost for this represents validation excavations where no further repair of the pipeline steel is required, while the higher cost includes an allowance for some minor repairs being required for the pipeline. Future repair or data validation would also be expected to cost this.
- Longer exposure to the untreated risk for the section upstream of the current duplication.

The benefits for this option include:

- An early reduction in risk for the section from Abbotts Road to Crib Point due to the initial ILI run recording accurate location, nature and magnitude of pipeline steel deterioration, and subsequent increased confidence of the integrity of this section.
- With the second ILI run, inspection of entire pipeline with accurate location, nature and magnitude of pipeline steel deterioration.
- Reduction of residual risk for the pipeline to Moderate (refer to Appendix A for risk ranking). This option significantly reduces the likelihood of a pipeline failure due to corrosion and is similar to Option 2.
- Baseline data will be available for assessing extension of the pipeline life once the design life is reached.

1.5.4. Option 4 – Recoat Pipeline

The fourth option that AGN has identified involves recoating all the accessible sections of the pipeline, which will require pipeline excavation, removal of existing coating, inspection of the pipeline, recoating in-situ with a modern coating and reinstatement.

This option won't allow for the pipelines to be inspected by ILI; however, with modern coating materials application methods and quality control the risk of a pipe wall defect developing to failure point within the design life of the pipeline is greatly reduced. Future management of structural integrity of the pipelines would then rely on indirect assessment of the coating (DCVG surveys) and subsequent direct inspection at localised coating defects.

1.5.4.1. Cost/Benefit Analysis

The costs of this option include:

- Recoating of the pipeline where accessible at an estimated cost of $40,000 ($000, 2016).
- Replacement of the final CPU anode bed at a cost of $54 ($000, 2016).
- Ongoing operational costs of the pipeline by means of coating inspection and subsequent excavations at a cost of $80 ($000, 2016), to address the continuing deterioration of those sections that cannot be accessed to replace the coating, and the expected deterioration of the new coating over time (although this is expected to be minimal). These costs are estimated from the number of anticipated coating faults requiring excavation from a newly coated pipeline, and the estimated cost of coating fault excavations of $12,750 per site, from the recently approved South Australian business case for the same activity (SA21a).
- Although there is a reduction in likelihood of a failure event, there is no overall reduction in residual risk for this option for the life of the recoated pipelines. This is because undetected corrosion may still develop on the pipeline, especially in sections which are not accessible.
- Residual risk for this option is still rated as High (see Appendix A).
- A cost benefit analysis of this option has been conducted (see Section 1.6.2), which shows that over the next 30 years of the pipeline's operation the cost of this option in present value terms is $37,341 ($000, 2016).

The benefits for this option include:

- direct examination of pipeline sections which are recoated; and
- modern coating less likely to degrade in the life of the pipeline.

The risk with this option is that those areas of the pipeline that cannot be accessed for recoating contain defects that develop to failure within the remaining life of the pipeline.

1.6. Summary of Cost/Benefit Analysis

1.6.1. Summary

Table 1.6 provides a summary of options presented in this business case. Other options, including replacement of the pipeline, were not presented in this business case because they were not considered the most cost effective solution.

Table 1.6: Summary of Cost/Benefit Analysis

Option	Benefits	Costs/Risks
Option 1	No upfront capital costs	• Ongoing costs of $600 ($000) in opex every five years, escalating as the coating condition deteriorates. • Some sections of the pipeline will remain inaccessible for inspection. • Limited means to demonstrate pipeline baseline integrity. • Residual risk ranking High. • NPV value of -$4,980 ($000).
Option 2	• Inspection of entire pipeline with accurate location, nature and magnitude of pipeline steel deterioration. • Baseline data available for assessing extension of pipeline life.	• Total initial cost of $1,717–$2,227 ($000). • Ongoing costs of $635- $715 ($000) ($555 ($000) in capex and $80- $160 ($000) in opex) likely every 10 years for ILI and subsequent repairs / verifications. • Residual risk ranking of Moderate. • NPV value of -$2,954 ($000)
Option 3	• Early inspection, and subsequent risk reduction, of the section from Abbotts Rd to Crib Point, with accurate location, nature and magnitude of pipeline steel deterioration. • Inspection of entire pipeline with accurate location, nature and magnitude of pipeline steel deterioration; • Baseline data available for assessing extension of pipeline life.	• Total initial cost of $2,097-$2,447 ($000) in the next AA period. • Total initial cost of $935 - $1,015 ($000) in the 2023-2027 AA period. • Longer exposure to untreated risk for the section upstream of the current duplication. • Ongoing costs of $635 - $715 ($000) ($555 ($000) in capex and $80- $160 ($000) in opex) likely every 10 years for ILI and subsequent repairs / verifications. • Residual risk ranking Moderate. • NPV value of -$3,918 ($000)
Option 4	• Direct examination of pipeline sections which are recoated. • Modern coating less likely to degrade in life of pipeline.	• Total initial cost of $40,032 ($000). • Residual risk ranking High. • NPV value of -$37,341 ($000)

1.6.2. Cost Benefit Analysis Modelling

The four options have been subjected to cost / benefit analysis modelling, the result of which is shown in Table 1.7 below (see Supporting Information 2 for further detail).

Table 1.7: Cost Benefit Analysis Results

Option	NPV ($000, 2016)
Option 1	-$4,980
Option 2	-$2,954
Option 3	-$3,918
Option 4	-$37,341
Discount Rate (real pre-tax WACC)	**3.14%**

1.7. Proposed Solution

1.7.1. What is the Proposed Solution?

From the options presented in Section 1.5, Option 2 has been selected because it is the most cost effective way to reduce the risk associated with corrosion and deterioration of pipelines (see Table 1.7) and achieves a reasonable balance between residual risk and cost.

1.7.2. Why are we Proposing this Solution?

Option 1 is not considered a feasible solution because the untreated risks are High and it will affect the safety and integrity of services and AGN's ability to meet existing demand. This option has the second lowest NPV of the options reviewed. Option 4 is technically feasible but is more expensive by orders of magnitude and so is not considered the most effective solution at this point in time. This option had the highest NPV of the options reviewed.

Options 2 and 3 provide a cost effective method of being able to demonstrate structural integrity of the pipeline, and lower the risk of pipeline failure due to unknown deterioration due to undetected corrosion. These two options are also deliverable in the next AA period.

Option 2 is however, preferred over Option 3 due to the additional initial cost associated with a larger scope of works both for the inspection tool launcher installation and a second ILI run under Option 3. This resulted in Option 2 having the lowest NPV of options reviewed, while Option 3 had the second highest NPV of options reviewed.

While Option 3 largely provides the same benefits as Option 2, it is at a much higher cost, and also leaves a section of the DCP with the same risk profile as the current situation for a longer period. This section of the pipeline also has a higher risk profile due to industrial encroachment and is inaccessible for coating inspection.

For the purposes of this business case it has been assumed that V23 will proceed as planned and that Option 2 is therefore the best option to implement.

1.7.3. Forecast Cost Breakdown

A detailed cost breakdown is included in Appendix C, which is summarised in Table 1.9:

Table 1.8: Project Cost Estimate ($000, 2016)

	2018	2019	2020	2021	2022	Total
Inspection Tool Traps Installation	$392	$651	-	-	-	$1,043
ILI Run[4]	-	-	-	$555	-	$555
Repair / Validation	-	-	-	-	$590	$590
CPU anode bed Refurbishment	$54	-	-	-	-	$54
Total	**$446**	**$651**		**$555**	**$590**	**$2,242**

Table 1.9: Capex/Opex Split ($000, 2016)

	2018	2019	2020	2021	2022	Total
Capex	$446	$651	-	$555	-	$1,652
Opex	-	-	-	-	$590	$590
Total	**$446**	**$651**		**$555**	**$590**	**$2,242**

The detailed cost breakdown has been prepared for individual items based on the costs of comparable projects recently completed, such as the Amcor Pipeline decommissioning, Wandong City Gate, Melrose Drive Field Regulator, Tumut Valley Pipeline ILI and Donnybrook City Gate, all of which were subject to competitive tender processes.

The following assumptions have been made in preparation of the cost breakdown:

- Compulsory acquisition will not be required to obtain land for the pig trap sites.
- Most engineering works and field supervision of contractors will be undertaken by internal resources.
- New weld procedures will be required to complete the works.

Externally purchased materials and contracts for field works will be procured using competitive tender processes.

1.7.4. Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN considers the forecast capex for this project to be:

- *Prudent* – AGN has considered four alternatives, and has selected the least cost option, and that which reduces the overall residual risk associated with coating degradation in older pipelines to as low as reasonably practical. This is consistent with what would be expected of a prudent service provider.
- *Efficient* – The estimated costs for this project can be considered efficient because they are planned to be carried out in conjunction with other related projects on the pipeline in order to extract the maximum value from design, procurement, approvals, contractor management and

[4] ILI run will be conducted late in 2021, following completion of Business Case V23 capital works in early 2021.

construction. The manner in which AGN intends to carry out the work (i.e. field work to be carried out by an external contractor that has demonstrated specific expertise in completing the installation of the assets in a safe and cost effective manner and that will be selected through a competitive tender) can also be considered efficient. The expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.

- *Consistent with accepted good industry practice* – ILI of transmission pipelines is seen as the industry standard for demonstrating pipeline integrity. For pipelines with vintage coatings which are degrading, ILI is the most complete and accurate method available to ensure the reduction of risk is to as low as reasonably practicable in a manner that balances cost and risk and is consistent with Australian Standard AS2885. The refurbishment work described above is necessary to enable work to perform the ILI, and to ensure the pipeline's corrosion protection system continues to be compliant with standards.
- *Achieves the lowest sustainable cost of delivering pipeline services* – The NPV of the proposed solution is the lowest of the options considered and the sustainable delivery of services including reducing risks to as low as reasonably practicable and maintaining reliability of supply.

The capex can therefore be viewed as being consistent with rule 79(1)(a) of the NGR. The proposed capex is also consistent with rule 79(1)(b), because it is necessary to:

- maintain and improve the safety of services (rule 79(2)(c)(i)) by improving the ability to detect potential pipeline leakage location, especially those locations that are inaccessible to ground surface based indirect assessment methods;
- maintain the integrity of services (rule 79(2)(c)(ii)) by providing an enhanced ability to detect deteriorating corrosion protection levels and pipeline defects by carrying out ILI runs; and
- maintain AGN's capacity to meet existing levels of demand for services existing at the time the capex is incurred (rule 79(2)(c)(iv)) by conducting pro-active activities that address potential failures before they occur.

1.7.4.1. Opex Component

Following the initial ILI, the operating practices for the pipeline will change from indirect measurement of pipeline coating and subsequent coating fault excavations to ILI examinations and subsequent targeted excavations for direct examination of identified defects and comparison of actual defects to the ILI data. This will provide the data for development of future ILIs and repair programs.

It is anticipated from previous experience with pipelines modified to undertake ILIs, that the opex associated with the direct examination excavations generated from ILIs will be similar when compared with those generated from DCVG surveys. This is because while more defect sites would be generated by the ILI, the pipe wall characteristics are measured very accurately by the ILI tool, and the defects and anomalies can be assessed accurately. Thus only those actually requiring repair or detailed examination are excavated, rather than having to perform excavations to assess the pipe wall condition.

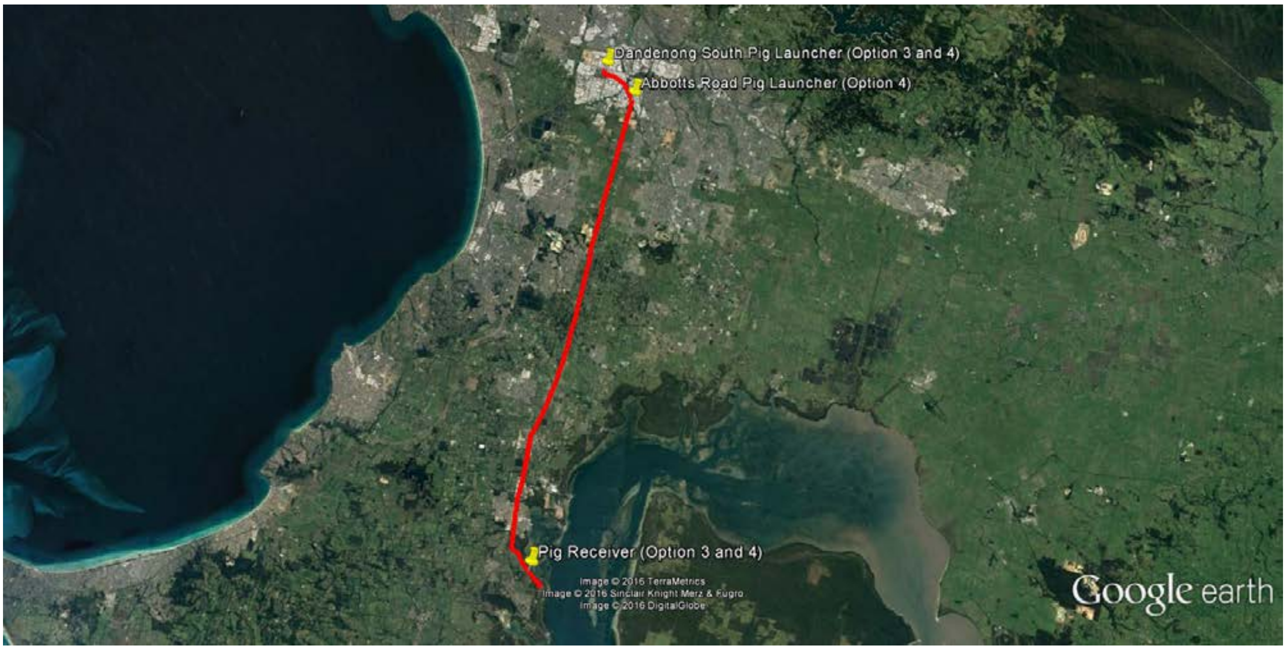
Thus a step change in base year opex is not anticipated to be required.

Appendix A – DCP Technical Details and Overview

Table A.1: Summary of DCP Technical Details

Pipeline Parameter	Value
Original Design Code	USA Standard Code for Pressure Piping USAS B 31.8
Current Operation Code	Australian Standard 2885.3 – Operation and Maintenance
Year Commissioned	July 1966
MAOP	2, 760 kPa
Design Life	80 Years
Design Factor	0.4
Pipeline Size	DN 300
Pipeline Length	39.12 km
Pipeline Material	API 5L Grade A
Pipeline Wall Thickness	6.35 mm
Depth of Burial	1,067 mm (Minimum)
External Coating	Coal tar enamel layer approximately 2.4 mm thick. Internally reinforced with a random mesh fiberglass mat and externally reinforced with a bonded tar impregnated asbestos felt outer wrapping.
Internal Coating	Red lead paint layer approximately 0.1 mm thick.
Cathodic Protection Units	3
Station Offtakes	8
Pipeline Offtakes	5
Location Classes	T1, R2, HI, I, CIC, W

Figure A.1: Overview of DCP Location



Appendix B – Risk Assessment

Figure B.2: Risk Assessment

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Option Risk
Risk Untreated	**Likelihood**	*Unlikely*	*Unlikely*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	**HIGH**
	Consequence	*Medium*	*Minor*	*Major*	*Major*	*Major*	*Medium*	*Major*	
	Risk Level	*Moderate*	*Low*	*High*	*High*	*High*	*Moderate*	*High*	
Residual Risk Option 1	**Likelihood**	*Unlikely*	*Unlikely*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	**HIGH**
	Consequence	*Medium*	*Minor*	*Major*	*Major*	*Major*	*Medium*	*Major*	
	Risk Level	*Moderate*	*Low*	*High*	*High*	*High*	*Moderate*	*High*	
Residual Risk Option 2	**Likelihood**	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	**MODERATE**
	Consequence	*Medium*	*Minor*	*Major*	*Major*	*Major*	*Medium*	*Major*	
	Risk Level	*Low*	*Negligible*	*Moderate*	*Moderate*	*Moderate*	*Low*	*Moderate*	
Residual Risk Option 3	**Likelihood**	*Rare*	*Rare*	*Rare*	*are*	*Rare*	*Rare*	*Rare*	**MODERATE**
	Consequence	*Medium*	*Minor*	*Major*	*Major*	*Major*	*Medium*	*Major*	
	Risk Level	*Low*	*Negligible*	*Moderate*	*Moderate*	*Moderate*	*Low*	*Moderate*	
Residual Risk Option 4	**Likelihood**	*Unlikely*	*Unlikely*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	**HIGH**
	Consequence	*Medium*	*Minor*	*Major*	*Significant*	*Significant*	*Medium*	*Major*	
	Risk Level	*Moderate*	*Low*	*High*	*High*	*High*	*Moderate*	*High*	

Appendix C – Detailed Cost Estimate

Table C.1: Inspection Tool Trap Installation ($2016)

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	
[redacted]	[redacted]
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[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Table C.2: CPU Replacement ($000, 2016)

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Table C.3: ILI Run ($000, 2016)

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Table C.4: Data Validation and Pipeline Repair ($000, 2016)

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Appendix D – Measurement Length Description

The measurement length is defined in AS 2885 Pipelines – Gas and Liquid Petroleum, Part 1: Design and Construction as:

> *"The measurement length is the radius of the 4.7 kW/m^2 radiation contour for a full bore rupture, calculated in accordance with Clause 4.10."*

This in essence clearly defines the region that could be affected by the worst case scenario of a pipeline failure, with the 4.7 kW/m^2 radiation contour being the level of energy density where an unprotected person will suffer second degree burns after 30 seconds of exposure.

The measurement length relevant to Australian Gas Networks pipelines varies and is determined by the diameter of the pipeline and the operating conditions of the fluid transported. Also, in accordance with AS 2885.3 (Part 3, Operations and Maintenance), a regular qualitative safety analysis is undertaken on each pipeline to determine what physical and procedural controls are required for the type and density of population within the measurement length of a pipeline. This is undertaken to ensure that the risk to the general public within the measurement length is at an acceptable level.

Business Case – Capex V89

Morwell Tramway Rd TP

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	Matthew Read, *Asset Inspection and Protection Manager*
Approved By	Andrew Foley, *General Manager Victorian Networks*

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	The Morwell to Tramway Rd transmission pressure (TP) pipeline is one of the earliest built pipelines in Australia (approximately 1957). The original pneumatic test pressure of this 80mm (DN80) main was set at 690 kPa but was increased with Ministerial approval in 1972 to 2,760 kPa without additional strength testing. Approximately 4 kilometres of the original DN80 continues to operate at 2,760 kPa. While the pipeline has operated at this pressure for over 40 years, Energy Safe Victoria (ESV) is now questioning whether the main should retain its 2,760kPa Maximum Allowable Operation Pressure (MAOP) on the grounds of safety and integrity of service. If ESV cannot be satisfied of this MAOP then they may direct Australian Gas Networks Limited (AGN) to reduce the pressure in the pipeline. If, notwithstanding this direction, AGN continues to operate the pipeline at the 2,760 kPa it will be in breach of the *Gas Safety Act 1997*. ESV is due to make a decision on this in early to mid-2017. If ESV is not satisfied that the pipeline can continue in operation at 2,760 kPa, then either the pipeline will need to be hydrotested to establish that it can operate at this pressure or be replaced. If the final decision is to downgrade the MAOP, then it will affect supply to Morwell gas customers and customers on the Lurgi line, which supplies a number of major regional centers including Moe, Warragul, Trafalgar and Yarragon.
Options Considered	The following options have been considered on the assumption that the ESV directs AGN to reduce pressure in the pipeline: • *Option 1:* Do nothing (i.e. fail to comply with AGN's licence conditions or operate at lower pressure and fail to supply customers in Morwell and regional areas supplied via the Lurgi Line). • *Option 2*: Hydrotest the pipeline and establish that it can operate at a MAOP of 2,760 kPa. Note that the pipeline will need to be taken out of service for this, and there is a risk that this test will result in the pipeline failing and expensive reactive replacement will be required. • *Option 3:* Replace the affected section of the pipeline with a new 3 kilometre x 100mm TP steel pipeline. • *Option 4:* Split the Morwell supply from the Lurgi Line by installing a new city gate facility at Firmins Lane and replace the affected pipeline with a 1.5 kilometre x 100mm TP steel pipeline. While Options 3 and 4 both involve the replacement of the pipeline, Option 4 also provides for supply to Morwell and the Lurgi Line to be separated from each other. Currently,

	pressure changes on the Lurgi line impact Morwell supply and vice versa, and this is a significant operational issue for the broader Declared Transmission System (DTS).
Proposed Solution	Option 4 has been selected because it is the most cost effective and beneficial way of dealing with any direction from the ESV, given the risks that hydrotesting poses and the costs of ensuring adequate supply during the hydrotest period.
Estimated Cost	The forecast capital expenditure (capex) for Option 4 over the next (2018 to 2022) Access Arrangement (AA) period is $3,349 ($000, 2016).
Consistency with the National Gas Rules (NGR)	The augmentation complies with the new capital expenditure criteria in rule 79 of the National Gas Rules (NGR) because: • it is necessary to maintain and improve the safety of services and maintain the integrity of services and comply with a regulatory obligation (rules 79(2)(c)(i) (ii) and (iii)); 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	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Reliability theme as its implementation will allow AGN to continue providing a highly reliable supply of natural gas to our customers by replacing the Morwell to Tramway Road pipeline. More information detailing the results of AGN's stakeholder engagement process is provided in Chapter 5 of the Access Arrangement Information (AAI, Final Plan) document.
Supporting Information	• Supporting Information 1 – Correspondence from ESV

1.3. Background

The original 80 mm Morwell to Tramway Road pipeline is one of the earliest built in Australia. The pipeline was constructed and commissioned in 1957 by the Gas and Fuel Corporation and was originally designed to transport manufactured gas from the Lurgi gasification plant to residential and industrial consumers in Morwell and Traralgon. Because the pipeline was constructed prior to the introduction of the *Pipelines Act 2005* (Victoria), the original material certificates are not available. There is therefore limited information available on the design and construction of this pipeline, which contributes to uncertainty over the pipeline MAOP. AGN is aware though that in 1970 the pipeline was converted to transport pressurised natural gas and that since 1974 the pipeline has operated with a licenced MAOP of 2,760 kPa.

The DN80 Morwell to Tramway Road pipeline is now approximately 4.1 kilometres in length (see Appendix B) and is used to supply customers in Morwell and regional areas supplied by the Lurgi Line, such as Moe, Warragul, Trafalgar and Yarragon. The pipeline was originally 11.4 kilometres in length; however, the 7.3 kilometre section downstream of Tramway Road was disconnected from the pipeline and has operated as a distribution main since 1981. A 0.6 kilometre section of the original pipeline was replaced with DN100 API 5L Grade B coated with Extruded Polyethylene (PE) line pipe in 1989 to accommodate construction of the Princes Freeway. The pipeline is also partially duplicated in 1987 with another section of DN100 API 5L Grade B coated with Extruded PE to provide additional supply to the now decommissioned Brown Coal Liquefaction plant.

The 4.1 kilometre length of the original pipeline is currently operating at an MAOP of 2,760 kPa, which is greater than the original pneumatic pressure test of 690 kPa. Ministerial approval was provided in 1972 to upgrade the MAOP of the pipeline without additional strength pressure testing. The pipeline has been operating at the higher pressure since 1974.

While the pipeline has been operating at this pressure for over 40 years, during review of plans to repair a non-leaking defect on the pipeline, ESV questioned whether the pipeline is suitable to retain a 2,760 kPa MAOP on safety and integrity of service grounds (see Supporting Information 1). Under the *Gas Safety Act 1997* (Part 6, Division 1, Section 106b) ESV may direct AGN to make adjustments to the gas flow or to pressure in the Morwell to Tramway Road pipeline if the Director considers that necessary to do for safety reasons. If AGN fails to comply with such a direction it may be subject to:

- corporate penalties of up to $228,000; and / or
- personal penalties of $46,000, three years' imprisonment, or both.

AGN has undertaken a risk based integrity review of the pipeline and has submitted the results to the ESV, which was initially due to make a decision in August 2016, but has been delayed until early to mid-2017. If it is not satisfied that the pipeline can continue in operation at 2,760 kPa, then either the pipeline will need to be hydrotested to establish that it can operate at this pressure or be replaced. Hydrotesting involves taking the pipeline out of service, and pressurisation of it with water in order to determine its strength and leak tightness at the proposed MAOP. This has the effect that defects in the pipeline that may otherwise become critical during in-service operation would fail during the hydrotest. The hydrotest effectively establishes the pipeline's suitability for continued service at the desired MAOP.

The configuration of the original Morwell Tramway Road means that any reduction of the MAOP could affect the supply of gas to 6,800 customers in Morwell and 65,000 customers in a number of major regional centres supplied via the Lurgi Line. Operating the original pipeline at a lower pressure is not a viable option, because a lower pressure would not provide adequate capacity to support this number of customers. The pipeline will thus either need to be hydrotested to confirm its suitability to continue with an MAOP of 2,760 kPa or replaced if the ESV concludes that the pressure should be reduced.

There is some ability to deliver gas via a the adjacent network of Traralgon which would be sufficient to retain supply to selected customer types (medical facilities and similar). The overall effect to customers by loss of the trunk main into Morwell would be near total loss of supply in Morwell.

If the ESV reaches such a conclusion then, irrespective of whether the pipeline is hydrotested or replaced, the works will be required to comply with a regulatory obligation (rule 79(2)(c)(iii)) and to maintain the safety and integrity of services (rules 79(2)(c)(i)-(ii)). The works will also be required to meet existing levels of demand in the Morwell area and regional areas supply by the Lurgi Line (rule 79(2)(c)(iv)).

1.4. Risk Assessment

The untreated risks associated with this project are summarised in Table 1.3. Further detail on the risk assessment is provided in Appendix A to this business case, which has been developed on the basis that the ESV concludes that it is not satisfied that the pipeline can operate at its current MAOP of 2,760 kPa.

Table 1.3: Risk Rating

Risk Area	Untreated Risk Level
Health and Safety	Negligible
Environment	Not applicable
Operational	High
Customers	High
Reputation	High
Compliance	High
Financial	Moderate
Untreated Risk Rating	**High**

As this table shows, if the ESV are unwilling to allow the Morwell Tramway Road main to continue to operate at 2,760 kPa then the main untreated risks are:

- regulatory compliance risk if AGN continues to operate the main at 2,760 kPa (i.e. because if AGN fails to comply with this obligation then it will be contravening its licence conditions), which is why this risk has been rated as 'High'; and
- operational, customer and reputational risks if AGN operates the main at a reduced pressure, because the current configuration of the Morwell Tramway Road means that any reduction in MAOP would affect to supply to Morwell and regional centres supplied via the Lurgi Line, which is why this risk has also been rated as 'High'.

In the event that interruptions to supply occur, depending on the circumstances and duration of interruption AGN may be required to make a Guaranteed Service Level (GSL[1]) payment to each affected customer.

1.5. Options Considered

AGN has identified the following options that could be employed if the ESV is not satisfied that the pipeline can continue to operate at 2,760 kPa:

1. *Option 1:* Do nothing (i.e. fail to comply with AGN's licence conditions or fail to supply customers).
2. *Option 2:* Hydrotest the pipeline and establish that it can operate at an MAOP of 2,760 kPa.
3. *Option 3:* Replace the affected section of the pipeline with a new 3 kilometre x 100mm TP steel pipe.

[1] The (GSL payment is intended to ensure that customers are compensated if an energy distribution company does not meet certain minimum performance standards. The amount payable and the conditions under which a GSL payment is triggered are set out in Part E of the Code. For supply interruptions, repeated or lengthy interruptions would incur a GSL of between $150 and $300 per affected customer. Refer ESC website for a copy of the Code: http://www.esc.vic.gov.au/document/energy/26123-gas-distribution-system-code-2/

4 *Option 4*: Split the Morwell supply from the Lurgi line by installing a new gate facility at Firmins Lane and replace the affected pipeline with a 1.5 kilometre x 100mm TP steel pipeline.

Further detail on these options is provided below.

1.5.1. Option 1 – Do Nothing

The Do Nothing option in this case, would either involve:

- AGN continuing to operate the original DN80 at 2,760 kPa, contrary to direction from ESV; or
- AGN reducing the pressure of the pipeline, but failing to supply all of its existing customers located in the Morwell area and major regional centres, supplied via the Lurgi Line.

1.5.1.1. Cost/Benefit Analysis

The only benefit of the Do Nothing option is that it does not give rise to any upfront capital costs. The costs, however, are significant because it would either result in:

- AGN failing to comply with direction from ESV if it continues to operate the pipeline at 2,760 kPa, which would be contrary to the *Gas Safety Act 1997* and may result in corporate and/or personal penalties; or
- AGN being unable to supply all of its existing customers located in Morwell and in the major regional centres, supplied via the Lurgi Line if it reduces the MAOP to comply with the ESV's directive. In accordance with the Victorian Gas Distribution Code, AGN must use all reasonable endeavours to ensure the minimum pressure is maintained at the distribution supply point. Losing supply to customers would result in GSL payments of –up to $300 and regional relight costs of [redacted].

Given the costs and risks associated with both of the sub-options under the Do Nothing option, it is not considered a feasible option.

1.5.2. Option 2 – Hydrotest the Original Pipeline

The second option that AGN has considered is hydrotesting the DN80 to establish that it can operate at an MAOP of 2,760 kPa. Hydrotesting an existing pipeline involves taking the pipeline out of service, purging all natural gas, conducting an over pressure test with water and then putting the pipeline back into service with natural gas.

1.5.2.1. Cost/Benefit Analysis

Carrying out a hydrotest on the 4.1km pipeline is estimated to cost $600 ($000, 2016). The hydrotest would require taking the pipeline out of service, which this estimate assumes would be during the time of lowest gas demand, with supply being maintained via some alternative method (for example Liquefied Natural Gas (LNG) vaporisation and injection). This would not be sustainable indefinitely though.

The key risk under this option is that the test causes the pipeline to fail and subject surviving defects to pressure reversal. AGN has judged there to be significant risk associated with this option because if the pipeline was to fail during hydrotest, the test would need to be conducted again once the failure point was repaired. Conducting multiple pressure tests on a pipeline may increase the probability of pressure reversal developing for defects[2], which lowers the failure pressure for a given defect that would otherwise have not failed during the operating life of the pipeline. The end result would be that the pipeline would be out of service for a longer time, increasing temporary supply costs and risk of supply due to a longer outage.

If the pipeline does fail, then the DN80 would need to be replaced immediately in order to ensure that supply to Morwell and regional centres can be maintained. An estimate of the costs associated with carrying out the reactive replacement has not been developed, as well as markedly increased costs of temporary supply, but can be expected to be approximately double the planned replacement cost estimates set out in options 3 and 4. Given the costs and risks associated with this option it is not considered a feasible option.

1.5.3. Option 3 – Replace the Affected Section of the Pipeline with a New 3 kilometre x 100mm TP Steel Pipe

The third option that AGN has considered would involve duplicating the remainder of the DN80 pipeline by extending the DN100 duplication by 3 kilometre. Use of DN100 would match the remaining trunk main in the network, and provide some additional measure of capacity improvement into Morwell. The lower length (vs the length decommissioned) is because of the existing partial duplication of the pipeline with DN 100. Completing this duplication would allow the DN80 section to be isolated and decommissioned.

1.5.3.1. Cost/Benefit Analysis

Building a 3 kilometre x 100mm TP steel pipeline is estimated to cost $2,559 ($000, 2016). Refer to Appendix B for the detailed cost estimate. The main benefits of this option are that it will:

- enable AGN to comply with its licence conditions and to continue to supply customers in Morwell and regional centres;
- enable supply to Morwell and regional centres to be maintained while construction of the new transmission pressure pipeline is underway, after which the original DN80 can be decommissioned; and
- result in the untreated risk falling from ‘High’ to ‘Negligible’ (see Appendix A).

This option will also address the documentation issues that AGN has experienced in relation to the original pipeline because, as noted in Section 1.3, there is limited design and construction information available on this pipeline.

1.5.4. Option 4 – Split the Morwell Supply from the Lurgi Line by Installing a New Gate Facility at Firmins Lane and Replace the Affected Pipeline with a 1.5 kilometre x 100mm TP Steel Pipeline

The final option that AGN has identified is to split the Morwell supply from the Lurgi Line by using the existing offtake at Firmins Lane and installing a new customer transfer meter and regulating facility. From there 600 metres of DN100 transmission steel could be tied in to the existing DN100 crossing of the Princes Freeway, before installing a further 900 metres of DN100 to the Morwell regulating facility (see Appendix D).

[2] Pressure reversal is the failure of a defect at lower pressure than the pipeline was originally tested to (and the defect has previously survived).

1.5.4.1. Cost/Benefit Analysis

Building a new gate facility at Firmins Lane and a 1.5 kilometre x 100mm TP steel pipeline is expected to cost a similar amount to Option 3 (i.e. $4,530 ($000, 2016)). Like Option 3, this option will also:

- enable AGN to comply with its licence conditions and to continue to supply customers in Morwell and regional centres;
- enable supply to Morwell and regional centres to be maintained while construction of the new TP pipeline is underway, after which the original DN80 can be decommissioned;
- result in the untreated risk falling from 'High' to 'Negligible' (see Appendix A); and
- address the documentation issues that AGN has experienced in relation to the original pipeline.

While this project is estimated to cost a similar amount to Option 3 and offer similar baseline benefits it is expected to offer an additional benefit, which is that it will split the supply to Morwell from the supply to the Lurgi line. Currently if pressure in the Morwell Tramway Road main needs to be adjusted, this also requires adjusting pressures to the Lurgi line, which, in turn, affects supply to the Jeeralang power station and a number of regional centres (including Moe, Trafalgar, Yarragon and Warragul) as well parts of the outer south east metropolitan Melbourne. The effect can be significant, which is why this is considered a major additional benefit of the Option 4 relative to Option 3. Splitting supply will only cost $30 ($000, 2016) more than Option 3, which is substantially lower than the cost that would be incurred if this was carried out as a separate project.

1.6. Summary of Cost/Benefit Analysis

Table 1.4: Summary of Cost/Benefit Analysis

Option	Benefits	Costs/Risks
Option 1	Avoids up front capex.	While there are no direct costs associated with this option, if AGN failed to comply with its AGN's licence conditions would expose AGN to significant costs and risks. If AGN did comply with its licence conditions, then reducing the MAOP would result in it failing to supply customers in Morwell and regional centres via the Lurgi Line, which would also expose AGN to costs and risk.
Option 2	If the hydrotest is successful this option will cost less to implement than options 3 and 4, but if it fails and damages the pipeline it will be more costly than these two options.	$600 ($000, 2016) if hydrotest only. If the hydrotest fails, then the DN80 will need to be replaced immediately. The cost of doing this on a reactive basis is expected to be approximately $9,000k.
Option 3	This option will: • enable AGN to comply with its licence conditions and to continue to supply customers in Morwell and regional centres; • enable AGN supply to the Morwell and regional centres supplied via the Lurgi Line to be maintained while construction is underway. Following commissioning of the new TP main the original DN80 can be decommissioned;	$2,559 ($000, 2016).

	• result in the untreated risk falling from 'High' to 'Negligible' (see Appendix A); and • address the documentation issues that AGN has experienced in relation to the original pipeline because, as noted in section 1.3, there is limited design and construction information available on this pipeline.	
Option 4	This option will deliver the same benefits as Option 3 ((a)-(d)) and will also reducing the supply risk to customers in the regional areas serviced by the Lurgil Line by splitting supply.	$3,349 ($000, 2016).

1.7. Proposed Solution

1.7.1. What is the Proposed Solution?

If ESV advises AGN that it is not satisfied the DN80 pipeline can operate at 2,760 kPa then the proposed solution is Option 4, which will involve building a new gate facility at Firmins Lane and 1.5 kilometre of 100mm TP steel pipeline (two sections, one 600m and the other 900m).

1.7.2. Why are we Proposing this Solution?

Option 4 is being proposed because:

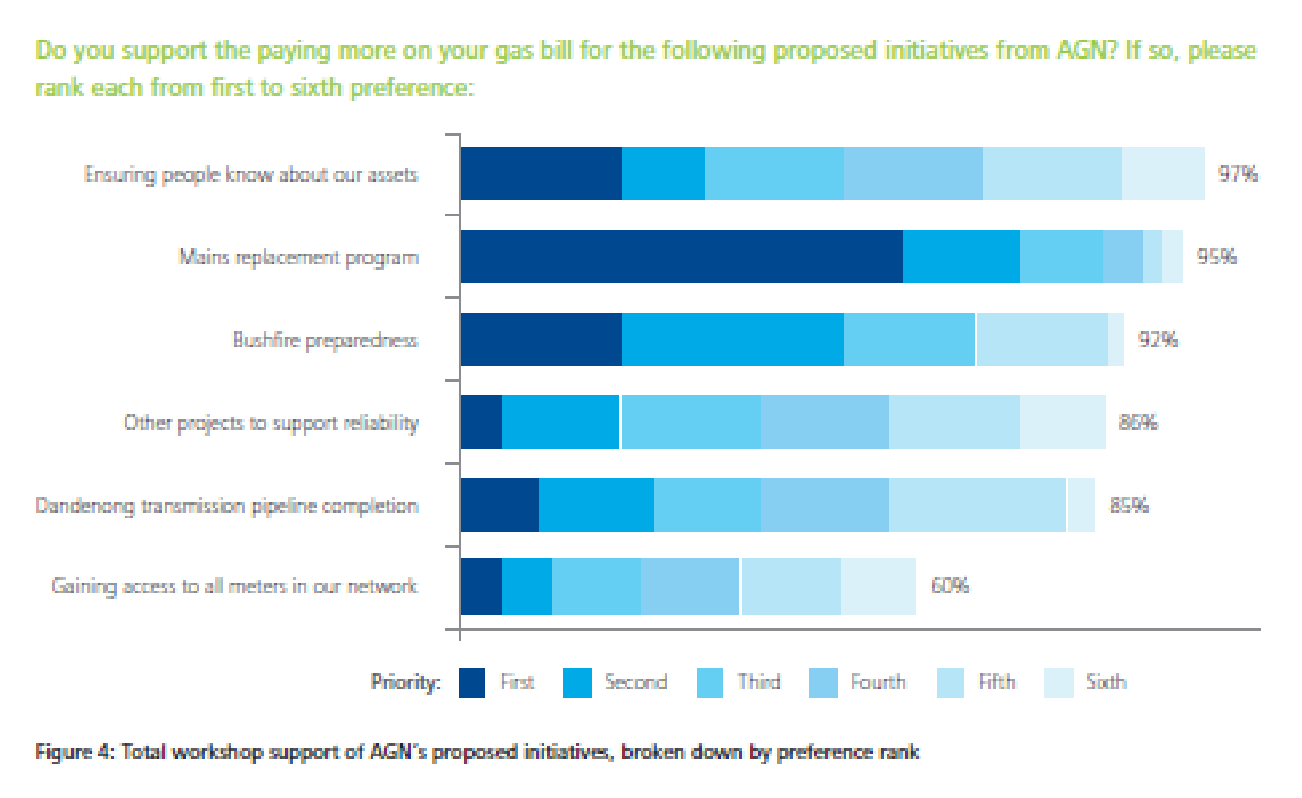
- Option 1 is not a feasible option given the costs and risks associated with either not complying with AGN's licence conditions, or not supplying existing demand in the Morwell area and regional areas supplied via the Lurgi Line.
- Option 2, while cheaper than options 3 and 4, may result in a loss of supply and more expensive reactive replacement if the hydrotest causes the pipeline to fail, which is a high risk. The risk is rated High owing to the increased cost of replacement if this needed to be done urgently, and also the cost of GSL payments to Morwell (if supply is lost).
- Options 3 and 4 are expected to cost roughly the same amount, but the added benefit of Option 4 is that it means that supply to the Lurgi Line is no longer linked to Morwell's supply, which is a significant benefit to customers located in regional areas supplied via the Lurgi Line and can be done at a relatively low cost through this project.

1.7.3. Stakeholder Engagement

Overall, our customers told us that they value current standards of reliability and are supportive of initiatives that maintain their reliability and improve the safety of the network with the majority of participants prepared to pay to support the maintenance of the existing level of reliability of the network, with the understanding that upgrades to meet population growth are necessary investments for the supply of gas for Victorian residents into the future.

Projects that support reliability received support from 86% of workshop participants, behind only awareness of AGN assets, ongoing mains replacement program and bushfire preparedness when ranked in order of importance.

Figure 1.1: Stakeholder Engagement Results



1.7.4. Forecast Cost Breakdown

A cost breakdown for Option 4 is included in Appendix B and is summarised in the following table:

Table 1.6: Capex/Opex Split ($000, 2016)

	2018	2019	2020	2021	2022	Total
Capex			1,116	1,116	1,117	3,349
Opex	New Custody Transfer Meter (CTM) – start operation in 2023					
Total			**1,116**	**1,116**	**1,117**	**3,349**

Charges associated with the new CTM will result in additional operating expenditure costs in 2023.

The cost breakdown for the gate station has been prepared for individual items based on the costs of comparable projects recently completed, including the Cobram City Gate and Melrose Drive Field Regulator upgrades, and the City Gate installation at Thewlis Road, Pakenham. The cost breakdown for the pipeline has been prepared based on feedback in the industry for pipelines in similar areas and comparable sizes.

1.7.5. Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN considers that the capital expenditure is:

- *Prudent*: The proposed expenditure is necessary to ensure that AGN can comply with its licence obligations and continue to supply customers in the Morwell area and regional centres supplied via the Lurgi Line. The proposed expenditure is also of a nature that a prudent service provider would incur as highlighted by the options analysis that has been conducted, which shows that the selected option is the most cost effective option given the risks associated with hydrotesting and the benefit of splitting supply.
- *Efficient*: The proposed installation of a gate station at Firmins Lane and the construction of a 1.5 kilometre x 100mm TP steel pipeline is the most cost effective and beneficial way of addressing any decision by the ESV to downrate the MAOP of the Morwell Tramway Road transmission pressure main. The proposed expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur. The manner in which AGN intends to carry out the work (i.e. field work to be carried out by an external contractor that has demonstrated specific expertise in completing the installation of the assets in a safe and cost effective manner and that will be selected through a competitive tender) can also be considered efficient.
- *Consistent with good industry practice*: Complying with ESV directives by replacing the portion of the pipeline that cannot operate at MAOP 2,760 kPa is consistent with accepted and good industry practice. So too is reducing the supply risk that customers in the areas serviced by the Lurgi Line are exposed to because of conditions in the Morwell area, by splitting supply where the costs of doing so is relatively low.
- *Achieve the lowest sustainable cost of providing the service*: The proposed solution is the most cost effective way of addressing AGN's licence obligations and offers the added benefit of splitting Morwell's supply from supply to the Lurgi Line. Splitting supply as part of this project will result in fewer issues in the areas supplied via the Lurgi Line and is more cost effective than doing it as a separate project. Proactively carrying out this project will also avoid reactive measures, thereby ensuring the lowest long-term sustainable cost for customers.

The capex can therefore be viewed as being consistent with rule 79(1)(a) of the NGR. The proposed capex is also consistent with rule 79(1)(b) because it is necessary to

- maintain and improve the safety of services (rule 79(2)(c)(i)) by replacing the section of the pipeline which ESV may deem unsafe to operate at the current operating pressure;
- maintain the integrity of services (rule 79(2)(c)(ii))) by installation of a modern pipeline to current standards and which is appropriately tested;
- comply with a regulatory obligation (rule 79(2)(c)(iii)) by following a potential directive from ESV and meeting licence obligations; and
- meet existing levels of demand (rule 79(2)(c)(iv) by pro-actively replacing the pipeline prior to directive to reduce pressure in the pipeline.

Appendix A – Risk Assessment

Figure A.1: Risk Assessment

		Health & Safety	Environment	Operational	Customer	Reputation	Compliance & Legal	Financial Impact	Total Score of Risk Level
Risk Untreated (Option 1)	**Likelihood**	Possible	N/A	Possible	Possible	Possible	Possible	Possible	High
	Consequence	Insignificant	N/A	Significant	Significant	Significant	Significant	Medium	
	Risk Level	*Negligible*	*N/A*	*High*	*High*	*High*	*High*	*Moderate*	
Residual Risk – Option 3 and 4	**Likelihood**	Rare	N/A	Rare	Rare	Rare	Rare	Rare	Negligible
	Consequence	Insignificant	N/A	Insignificant	Insignificant	Insignificant	Insignificant	Insignificant	
	Risk Level	*Negligible*	*N/A*	*Negligible*	*Negligible*	*Negligible*	*Negligible*	*Negligible*	

Appendix B – Detailed Cost Estimate

Table B.1: Option 3 Detailed Cost

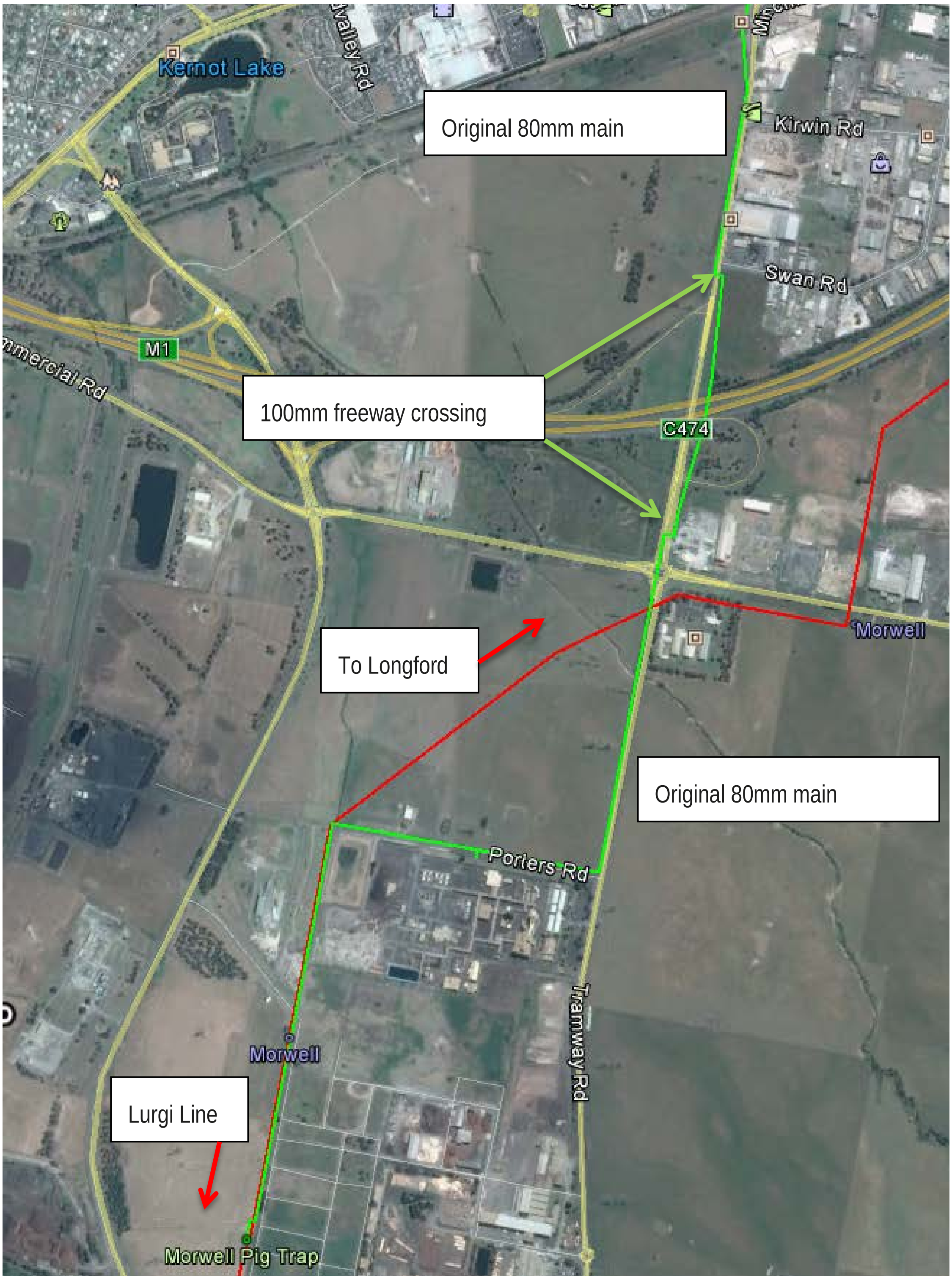
[redacted]

Table B.1: Option 3 Detailed Cost - Continued

[redacted]

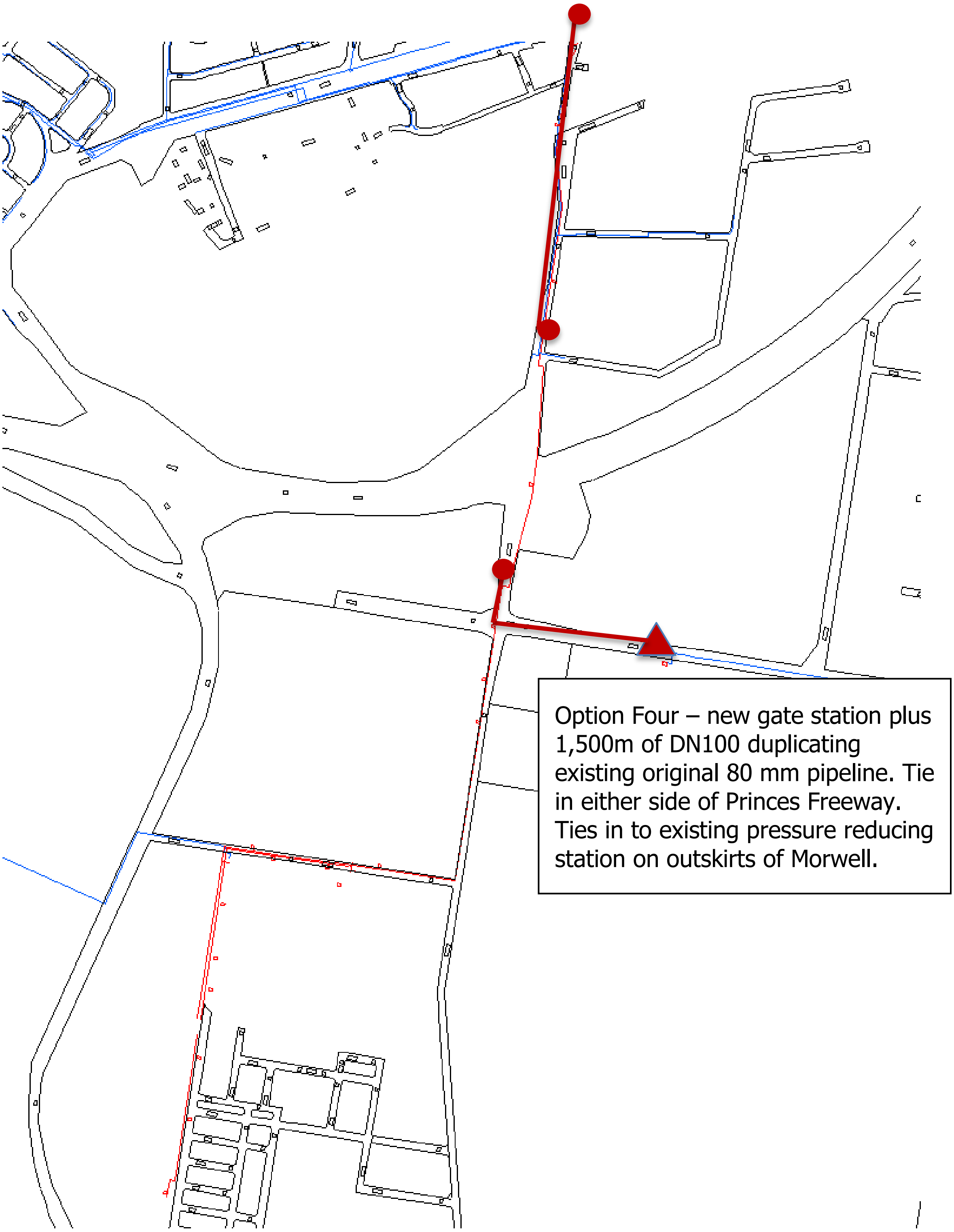
Appendix C – Existing Pipelines

Figure C.1: Existing Pipeline Map



Appendix D – Option 4 Map

Figure D.1: Option 4 Map



Business Case – Capex V102

H70 Moe

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	Keith Lenghaus, *Asset Planning Manager*
Approved By	Andrew Foley, *General Manager Vic Networks*

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	The Moe high pressure (HP) network (H70) supplies gas to the townships of Moe and Newborough located in the LaTrobe Valley of Victoria. Continuing residential growth within the area is expected to reduce pressures within the network to below the recommended minimum considered essential to maintain a safe and reliable supply of gas to consumers. Operating below the recommended minimum pressure could result in the loss of several hundred consumers. In circumstances where there is a momentary loss of supply there is a risk that this could lead to a gas in building incident causing major damage and or life threatening injuries. The risk associated with gas outage has been assessed as 'moderate' Augmentation of the network is required to meet AGN's obligations to: • Maintain network pressures above the distribution supply point minimum specified in the Victorian Distribution System Code (Code). Failure to do so would be considered a breach of AGN's license condition. • Maintain and improve the safety of services to consumers – Failure to do so could result in serious injury or damage to property • Maintain a reliable supply to consumers – Failure to do so would incur Guaranteed Service Level (GSL) payments and have potential, in the long term, to harm the reputation of natural gas as a reliable energy source promoting consumers to switch to alternatives. • Connect customers that are within minor or infill areas as required by the Code – Failure to do so would be considered a breach of AGN's license condition Viewed in this way augmentation of the Moe network is required to: • comply with the regulatory obligations set out in the Code; and • maintain and improve the safety and reliability of services.
Options Considered	The following options have been considered to address the growth in the Moe HP network: 1 Option 1: Allow ongoing growth to decrement capacity to the extent that supply loss becomes a more regular event. 2 Option 2: Control the amount of additional load of the network by either limiting connections or implement demand management (turn off during peak periods)

	3 Option 3: Augment the network by duplicating sections of existing steel and polyethylene (PE) mains (total of 420 metres) 4 Option 4: Defer augmentation into the following regulatory period Options 1, 2, and 4 are not considered feasible given the regulatory obligations to maintain a safe and reliable supply of gas to consumers. Option 3 is the only feasible solution which maintains a safe and reliable gas supply to existing consumers while supporting new connections to the existing network.
Proposed Solution	Option 3 has been selected because it is the most effective way to comply with regulatory obligations set out in the Code to maintain a safe and reliable supply of gas to customers. This option reduces the risk from 'medium to 'low' consistent with obligations under Australian Standard AS/NZ 4645.
Estimated Cost	The forecast capital expenditure (capex) over the next AA period for Option 3 is $227.5 ($000, 2016).
Consistency with the National Gas Rules (NGR)	The augmentation complies with the new capital expenditure criteria in rule 79 of the National Gas Rules (NGR) because: • it is necessary to maintain and improve the safety of services, maintain the integrity of services and comply with a regulatory obligation (rules 79(2)(c)(i),(ii) and (iii)); 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	AGN has undertaken a comprehensive stakeholder engagement program to better understand the needs and values of our stakeholders and customers. During this engagement, customers told us that they value current standards of reliability and are supportive of initiatives that maintain their reliability and improve the safety of the network. Implementation of this initiative will allow AGN to maintain the safety of the network while continuing to provide a highly reliable supply of natural gas to our customers. More information detailing the results of AGN's stakeholder engagement program is provided in Chapter 5 of the Access Arrangement Information document.

1.3. Background

1.3.1. General

The regional townships of Moe and Newborough are located in the Latrobe Valley approximately 130 kilometres east of the Melbourne Central Business District (CBD).

The Moe HP Network (H70) supplies gas to over 7,000 residential customers.

This network is supplied from a single gate station fed from the APA GasNet Morwell – Dandenong transmission pipeline. An overview map of the network is provided in Appendix A.

The trunk main supplying the Newborough area is a single DN100 steel trunk main crossing the M1, the Gippsland railway line and Narracan Creek limited. This trunk main has limited capacity to supply ongoing developments in the area.

Capacity modelling[1] has confirmed that ongoing residential growth in the area will reduce network pressures to below the minimum required to sustain a safe and reliable supply of gas. Modelling

[1] H70 2015 Network Capacity Review

has highlighted the need to duplicate the existing trunk main at two locations to ensure adequate pressures can be maintained throughout the network.

The remainder of this section details our obligations and explains why there is a need to deliver augmentation of the Moe network over the next AA period.

1.3.2. Regulatory Obligations and the Moe Network

1.3.2.1. Obligation to Maintain Supply Pressure

Under the Code[2], AGN has a regulatory obligation to use all reasonable endeavours to:

> *"…ensure the minimum pressure is maintained at the distribution supply point[3]."*

This requirement covers both distribution and transmission pipelines. In the Moe network, the minimum distribution system pressure required by the Code is 140 kPa.[4] Over the next AA period fringe pressures in Moe are expected to fall below the recommended design minimum commencing from the 2018 winter (refer to Table 1.4 for details).

1.3.2.2. Obligation to Connect

In addition to having an obligation to maintain supply pressures, AGN also has an obligation under the Code to connect customers that are within the minor infill extension areas.[5] Specifically, clause 3.1(c) of the Code states that:

> *"A Distributor must connect the gas installation of a customer that resides within the minor or infill extension area on fair and reasonable terms and conditions"*

The growth forecast discussed in the Section 1.4.2 is based on projected dwelling construction within areas that would be considered minor or infill extension under the Code.

1.3.2.3. Guaranteed Service Level

In the event that interruptions to supply occur, depending on the circumstances and duration of interruption AGN may be required to make a GSL[6] payment to each affected customer. GSL payment depends on the duration of customer outage with payments of up to $300 applicable for extended outages.

1.4. Key Drivers and Assumptions

1.4.1. Historic Growth

Figure 1.1 summarises the historic growth in the Moe and Newborough areas (postcode 3825) served by the Moe HP network.

[2] The Code has been developed by the Victorian Essential Services Commission and applies to all distributors that hold a distribution licence. The Code sets out the minimum standards for the operation and use of the distribution system, which include, amongst other things, minimum standards for connections and augmentations. As stated in the notes to section 3 of the Code, clause 4 of AGN's Gas Distribution Licence requires compliance with this Code.

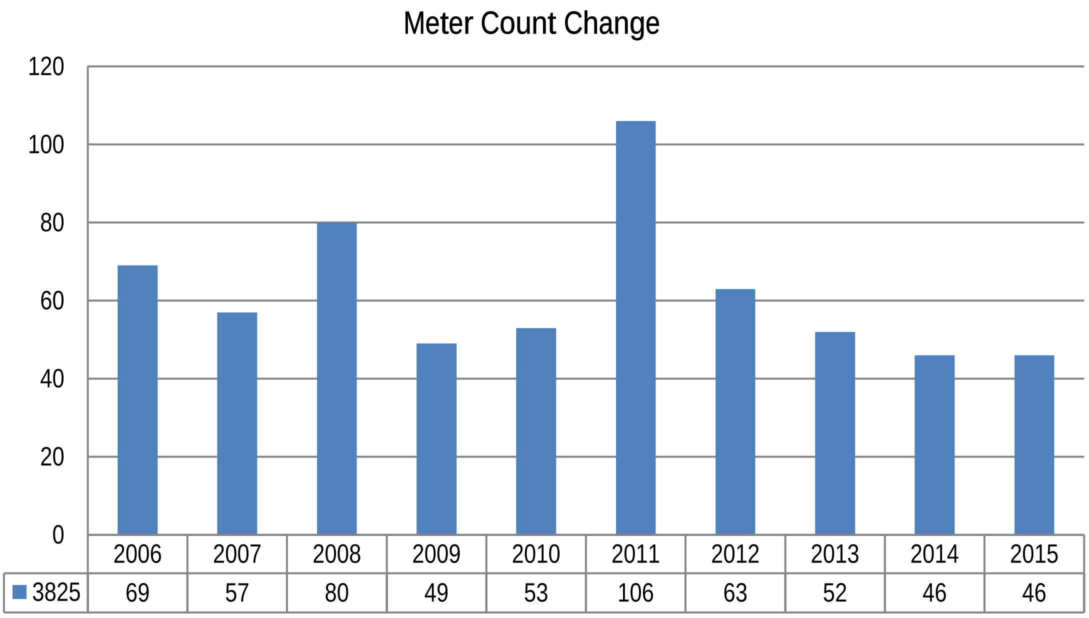
[3] Schedule 1 Part A of the Code

[4] This obligation is set out in Schedule 1 of the Code.

[5] The term 'minor and infill extension area' is defined in clause 2.1(f) of the Code as an area that is up to 1 km radially from the nearest part of the distribution system main.

[6] The GSL payment is intended to ensure that customers are compensated if an energy distribution company does not meet certain minimum performance standards. The amount payable and the conditions under which a GSL payment is triggered are set out in Part E of the Code. For supply interruptions, repeated or lengthy interruptions would incur a GSL of between $150 and $300 per affected customer. Refer ESC website for a copy of the Code: http://www.esc.vic.gov.au/document/energy/26123-gas-distribution-system-code-2/

Figure 1.1: Meter Connections Historic Growth



The five year average net connections from 2011 to 2015 are about 62 per year. The 10 year average is also around the 62 connections per year.

1.4.2. Future Demand

Table 1.3 summarises the criteria and assumptions used to establish demand in the Moe network over the next Access Arrangement (AA) period.

Table 1.3: Growth Assumptions

Criteria/Assumption	Basis
Average annual growth in net new tariff V customer will continue at an average of 62 connections per year	This is based on the five year historic average connection rate. A review of; the strategic outlook for Moe-Newborough and Lake Narracan[7], new estate plans for Monash Views[8] and Mitchell Grove[9] and consultation with the local council concluded that future growth of this order was likely to continue at the historic rate.
No additional Tariff D load	Tariff D Loads arrive unpredictably, and growth in D load has not been allowed for in this analysis. Tariff D load growth will be addressed on an as needed basis, with cost of connection assessed at the time of enquiry.
Average demand per Tariff V customer of 0.76 m^3/hour	The calculated ratio of tariff V design load to tariff V meter connection numbers in the Moe network. It should be noted that this can vary from location to location with actual averages of up to 1.0 m3/hr in some parts of the network.

[7] Strategic outlook for Moe-Newborough and Lake Narracan, State Government of Victoria, Growth Areas Authority, August 2013, accessed 28th August 2015, http://www.latrobe.vic.gov.au/Building_and_Planning/Development/Completed_Strategic_Projects/Lake_Narracan_Precinct_Structure_Plan

[8] <http://monashviews.com.au/> accessed 28th August 2015

[9] <http://www.mitchellgrove.net.au/> accessed 28th August 2015

1.4.3. Customer Impact

Continued growth in Moe and Newborough is expected to reduce network pressures at various locations within the Moe network over the next AA period. Table 1.4 summarises the impact on network pressures at various fringe point locations.

Table 1.4: Moe Network Minimum Pressure (kPa)

Location	2016	2017	2018	2019	2020	2021	2022
Hunter Street, Moe	251	247	244	240	236	232	228
Catani Court, Newborough	246	241	237	232	227	222	217
Desmond Street, Moe	311	308	305	301	298	295	292
Carbine Street, Moe	328	326	323	321	318	316	313
Leonis Court, Moe	263	259	255	252	248	244	240
Guy Street, Newborough	145	136	126	116	105	93	80
Number of customers < 140 kPa		600	1,700	2,000	2,100	2,300	2,400
Number of customers nil gas		0	0	0	0	0	0

The analysis shows that network pressures are expected to drop below the required minimum from about 2017 and continue to fall across the network over the next AA period.

The final two rows of this table set out:

- the number of customers that could be affected by the reduction in pressure below the 140 kPa Code requirement and could therefore be at risk of a transient gas outage[10]; and
- the number of customers that are at risk of receiving no gas at all if network pressures fall below atmospheric pressure.

It is estimated that over 2,000 customers could be impacted by poor system pressures by 2022 resulting in:

- transient and unpredictable interruptions to gas supply, occurring at increasing frequency year on year; and
- the potential for an outage to result in release of un-combusted natural gas from a burner that was extinguished during the outage but remained open up to the recovery of gas supply, leading to natural gas accumulation in a confined space followed by fire, explosion or asphyxiation.

Further detail on these risks can be found in Section 1.5

Taking action to address these issues is consistent with the findings of our stakeholder engagement program which found strong support from workshop participants for AGN to

[10] The term 'transient gas outage' is used in this context to refer to the situation where tariff V gas demand outstrips the network's supply capability for a relatively short period of time. This could occur on a gas day if peak demand is too large and the pressure at the end of the network drops to such a low level that customers in the area of low pressure experience an interruption in supply. Once the peak load starts to fall, the network pressures will start to recover and the supply of gas will return to these customers.

undertake key projects like this one to ensure reliability to existing customers is maintained, and which are necessary investments arising from the demands of ongoing customer connection growth.

1.4.4. Summary

Continued residential growth in the Moe and Newborough area will require the capacity of the Moe HP network to be augmented during the next AA period. This will be necessary to:

- maintain minimum gas pressures, as set out in the Gas Distribution Code, necessary for a safe and reliable supply of gas to existing consumers;
- avoid GSL payments and relight costs associated with gas outages; and
- meet AGN's obligation to supply 'infill' growth across the Moe/Newborough area.

1.5. Risk Assessment

A risk assessment of the following scenarios has been carried out in accordance with the APA Risk Policy and Risk Matrix.

Scenario 1. Organic Tariff V growth has reduced the Moe HP network pressure to below the recommended minimum during the winter peak demand period resulting in the loss of supply to up to 1,000 customers. This is considered an 'occasional' event as per the APA Risk Policy.

Scenario 2. Network pressure at the extremity of the HP network drops below the recommended minimum resulting in a momentary loss of supply to a number of consumers. This in turn causes a flame out on an appliance (cook top) and the subsequent return of supply results in a gas in building (GIB) incident that remains unnoticed by the occupant resulting in a fire or explosion. This is considered to be a 'rare' event as per the APA Risk Policy

The table below summarises the risks associated with these three scenarios. A detailed breakdown of the risk assessment has been provided in Appendix B.

Table 1.5: Risk Rating

Risk Area	Untreated Risk Scenario 1	Untreated Risk Scenario 2
Health and Safety	N/A	Moderate
Environment	N/A	Negligible
Operational	Moderate	Negligible
Customers	Low	Negligible
Reputation	Low	Moderate
Compliance	Moderate	Moderate
Financial	Low	Moderate
Untreated Risk Rating	**Moderate**	**Moderate**

The risk associated with the loss of supply has been assessed as 'moderate'.

While there is the potential for an outage to result in the release of un-combusted natural gas from a burner, leading to a fire, explosion the risk is also considered 'moderate' as the likelihood is rare.

AGN has an obligation under its license conditions to assess its asset risks and reduce any 'high' or 'moderate' risks to 'low' or 'negligible' and if not 'as low as reasonably practicable'.

1.6. Options Considered

AGN has considered the following options to address the network capacity issues outlined above.

1. Option 1: Allow ongoing growth to decrement the Moe network capacity to the extent that supply loss becomes a more regular event.
2. Option 2: Control the amount of additional load on the network by either limiting connections or implement demand management (turn off during peak periods).
3. Option 3: Augment the network by duplicating sections of existing trunk main feeding Newborough
4. Option 4: Defer augmentation into the following regulatory period

Further detail on these options is provided below.

1.6.1. Option 1 – Accept increasing risk of supply loss

Under this option, AGN will continue to accept network connections (as it is required to do under the Code) but do nothing to address the effect on the network design minimum pressures.

1.6.1.1. Cost/Benefit Analysis

The benefit of this option is that it does not give rise to any upfront capital costs. This option would, however, result in AGN contravening its regulatory obligation to use all reasonable endeavours to

> *"ensure the minimum pressure is maintained at the distribution supply point"*

and as a result the network design minimum pressures will be breached by an increasing amount and frequency each year, impacting an increasing number of customers in the Moe network.

This option does not address:

- *Reduced reliability and security of supply* – Connected customers towards the fringe of the network will not have 'un-fettered' use of the gas supply that they have paid for. Not all customers will be impacted equally, creating an inequitable supply privilege gradient where customers closer to the gate get a better level of service at the expense of customers at the network fringe. This is inconsistent with the intent of the gas regulatory framework (including the Access Arrangement framework), which is designed to ensure that all customers are treated equitably and are provided with access on a non-discriminatory basis.
- *Potential safety issues with the network* – A gas network that is not operating correctly or predictably is an unsafe network. A transient loss of gas gives rise to the risk of the release of un-combusted gas, as operating gas appliances do not necessarily respond to loss of gas by automatically turning off. As free gas is released there is the potential for it to collect in a confined space and eventually catch fire or explode, which poses a risk to human health and safety and property. Doing nothing to address the risk of gas intrusion is inconsistent with Australian Standard AS4645 (Gas Distribution Network Management), which requires that this must be managed to 'low' or 'negligible' and if not to 'as low as reasonably practicable'.
- *Increased Opex as result of GSL payments and relights* - The increased risk of an outage under this option also increases the likelihood that AGN will have to make GSL payments (lengthy interruptions incur a charge of $300 per affected property) and incur costs relighting customers, with the costs of the order of $40 per relight.

Given the risks posed by this option and the fact that it would result in AGN failing to comply with its regulatory and code obligations this option is not considered or prudent or viable option.

1.6.2. Option 2 – Control/Limit Additional Load

Under this option AGN would maintain the current network configuration without augmenting the network and limit network connections and or reduce consumption during peak periods. This would be aimed at ensuring pressures at the extremity of the Moe HP network are maintained above the required minimum ensuring that a safe and reliable supply can be maintained.

1.6.2.1. Cost/Benefit Analysis

Like Option 1, the benefit of this option is that it does not give rise to any upfront capital costs. However, this option is not considered prudent or viable for the following reasons:

- Limiting future connections would contravene AGN's regulatory obligation under the Code to connect customers that are with the minor or infill extension areas
- Existing contracts have not been structured to allow for 'turndown' of supply during peak periods. From a practical point of view it would be impossible to 'predict' capacity shortfalls in

the network with sufficient lead time to allow major consumers to reduce their consumption by shifting to alternative energy sources or curtailing operations.

No further consideration has therefore been given to this option.

1.6.3. Option 3 – Network Augmentation

The third option that AGN has considered is to augment the Moe HP network by duplicating sections of the HP trunk main feeding Newborough (refer to Appendix A Figure A.1 for location details). The scope and timing of this augmentation is summarized in Table 1.6 below.

Table 1.6: Staged Network Augmentation

Year	Infrastructure	Cost Estimate ($,000 2016)
Mains Infrastructure		
2018	250 metres x DN180 PE main along Railway Crescent from High Street to the railway	129
2018	60 metres x DN150 Steel main along Narracan Drive from the railway to Narracan Creek.	98.5
	Total Capital Expenditure	**227.5**

Several alternative duplications were modelled however none provided sufficient capacity to maintain pressures above the minimum of 140 kPa over the next regulatory period[11].

Option3 is expected to provide adequate capacity to sustain growth to at least 2022. Depending on the level of growth, further augmentation may be required in the following regulatory period (2023 – 2027)

1.6.3.1. Cost/Benefit Analysis

The capital cost of this Option 3 is $ 227.5 ($'000, 2016). Refer to Appendix C for a detailed cost breakdown.

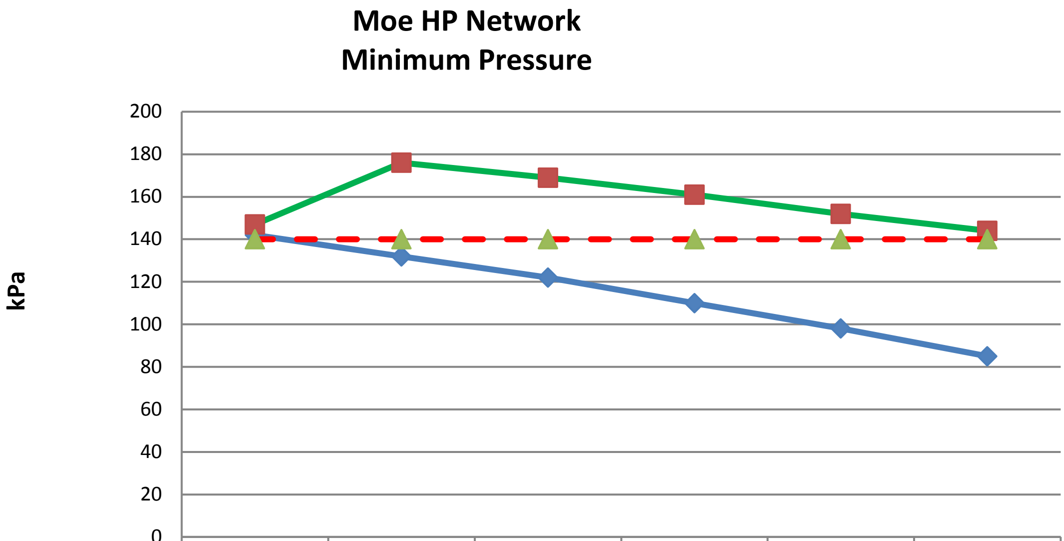
The benefit of this option is that it reduces risk of gas outage from 'moderate' to 'low' (refer to Appendix B), and in doing so:

- ensures compliance with AGN's regulatory obligations under the Code by:
  - ensuring that minimum network pressures are maintained at distribution supply points and, in so doing, maintain the integrity of services; and
  - allowing new connections to occur (as required by the Code), without risk to gas supply at the network fringe;
- maintains the safety of services by reducing the risk of gas intrusion and the associated risks to human health and safety to as low as reasonably practicable, consistent with Australian Standard AS4645; and
- reduces the likelihood that AGN will have to make GSL payments and incur costs in relighting customers if there is an outage.

Figure 1.2 summarises the expected minimum pressure at fringe point locations within the Moe/Newborough HP network given the proposed augmentation.

[11] H70 2015 Network Capacity Review

Figure 1.2: Network Pressure – Post Augmentation



	2017	2018	2019	2020	2021	2022
Without Augmentation	142	132	122	110	98	85
With Augmentation	147	176	169	161	152	144
Required Minimum	140	140	140	140	140	140

The proposed duplication will support forecast load growth at least through to the end of 2022.

1.6.4. Option 4 – Defer Augmentation

Deferring the augmentation into the following regulatory period (2023 – 2027) has been considered. This would require the acceptance of a 'moderate' risk of gas outage for several years. AGN would be non-compliant with its obligations to maintain a safe and reliable supply to consumers for the period of delay.

The cost of this option would effectively see Option 3 escalated to the future year of execution.

There would be a small cost saving (arising from the time cost of money) to customers from deferring the work. This cost saving is considered to be immaterial compared to being non-compliant, while posing an increased safety and supply risk and being inconsistent with the prudent and efficient operation of the network.

Given AGN's obligations, deferral was not considered prudent or efficient.

1.7. Summary of Cost/Benefit Analysis

Table 1.7 below provides a summary of costs, risks and benefits associated with the four options.

Table 1.7: Summary of Cost/Benefit Analysis

Option	Benefits	Costs/Risks
Option 1	Avoids up front capital expenditure.	No capital costs GSL payments of up to $300 per customer plus $40 per customer for relight in event of a gas outage. AGN would fail to comply with its regulatory obligations under the Code to use all reasonable endeavours to ensure safe and reliable supply of gas to consumers. Residual risk is 'moderate' Not a prudent option
Option 2	Avoids up front capital expenditure.	No capital costs Impractical to implement - contracts do not allow for demand management. AGN would fail to comply with its obligation under the Code to connect customers. Not a prudent option
Option 3	Ensures AGN complies with the pressure and connection provisions in the Code. Reduces the risk of gas outages and the associated risks to human health and safety to as low as reasonably practicable. Maintains the reliability of supply to existing consumers.	Capital costs $227.5 ($'000 2016) to duplicate sections of the existing trunk main to Newborough. This the recommended option based on reducing risk from 'moderate' to 'low' at the lowest cost.
Option 4	Deferral creates time value of money savings	No capital costs in the next regulatory period AGN would fail to comply with its regulatory obligations under the Code to use all reasonable endeavours to ensure safe and reliable supply of gas to consumers. Residual Risk is High Not considered a prudent option

1.8. Proposed Solution

1.8.1. What is the proposed solution?

The proposed solution is Option 3, which will involve duplicating sections of the trunk main feeding the Newborough area.

The scope, timing and costs are summarised in Section 1.6.3.

1.8.2. Why are we proposing this solution?

Option 3 has been selected because:

- The project is required to comply with regulatory obligations under the Code to maintain a safe and reliable supply of gas to customers.
- It is the most cost effective solution – The proposed augmentation represents the minimum amount of augmentation necessary to sustain growth over the next regulatory period. Depending on growth further 'staged' augmentation will be necessary in the following period.
- It is a low risk, technically simple and proven solution. Laying pipe in the ground provides a known capacity improvement for an expenditure amount that can be relatively accurately quantified. The risk of delivery is minimal, on either a time or budget basis.

1.8.3. Stakeholder Engagement

Overall, our customers told us that they value current standards of reliability and are supportive of initiatives that maintain their reliability and improve the safety of the network with the majority of participants prepared to pay to support the maintenance of the existing level of reliability of the network, with the understanding that upgrades to meet population growth are necessary investments for the supply of gas for Victorian residents into the future.

Projects that support reliability received support from 86% of workshop participants, behind only awareness of AGN assets, ongoing mains replacement program and bushfire preparedness when ranked in order of importance.

Figure 1.3: Stakeholder Engagement Results

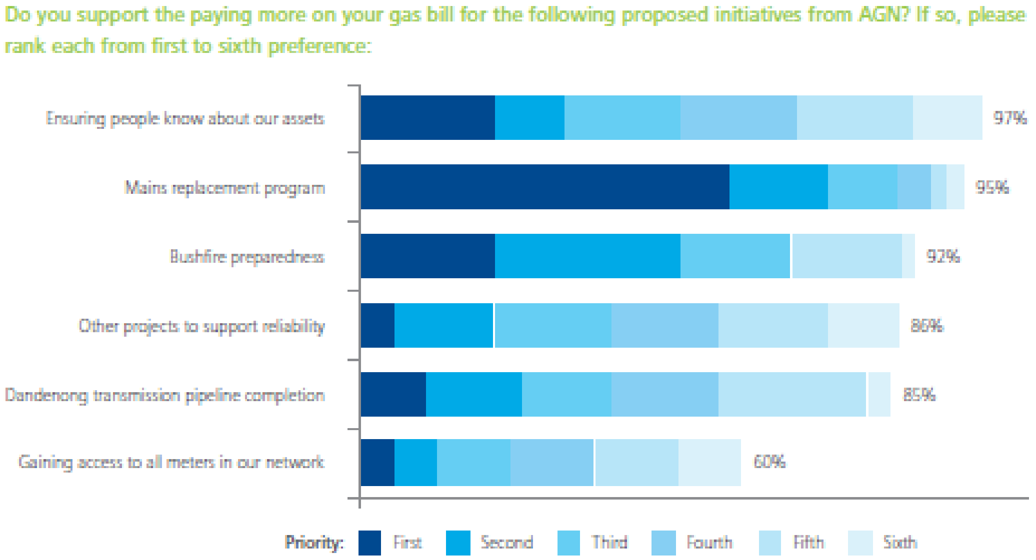


Figure 4: Total workshop support of AGN's proposed initiatives, broken down by preference rank

1.8.4. Forecast Cost Breakdown

Table 1.8 below provides a summary of the capex that is forecast to be incurred in the next AA period under Option 3, which has been estimated on the basis of the following assumptions:

- *Materials* – Where possible, the cost of the materials required is based on the price achieved for comparable works completed elsewhere in the network. Where a suitable cost estimate from outcomes is unavailable, the material cost is estimated from recent quotes received for other similar works and previous cost experience.

- *Labour* – where possible the labour costs have been based on the unit rate achieved as the result of competitive tender between external contractors. This is assumed to reflect the best efficient delivery cost achievable. For specialist services, the cost estimate is derived from the cost of basic due diligence for similar projects.
- *Project Timing* – projects have been sequenced to ensure manageable project delivery targets while avoiding breaching minimum pressures under design conditions. Where design condition assessment (Table 1.7) shows pressures below the Code minimum network management will ensure that supply is maintained.

A more cost breakdown can be found in Appendix C.

Table 1.8: Capex Split ($000, 2016)

	2018	2019	2020	2021	2022	Total
Land	-	-	-	-	-	**-**
Materials	38.3	-	-	-	-	**38.3**
Labour	189.2	-	-	-	-	**189.2**
Total	**227.5**					**227.5**

1.8.5. Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the National Gas Rules, AGN considers that the capital expenditure is:

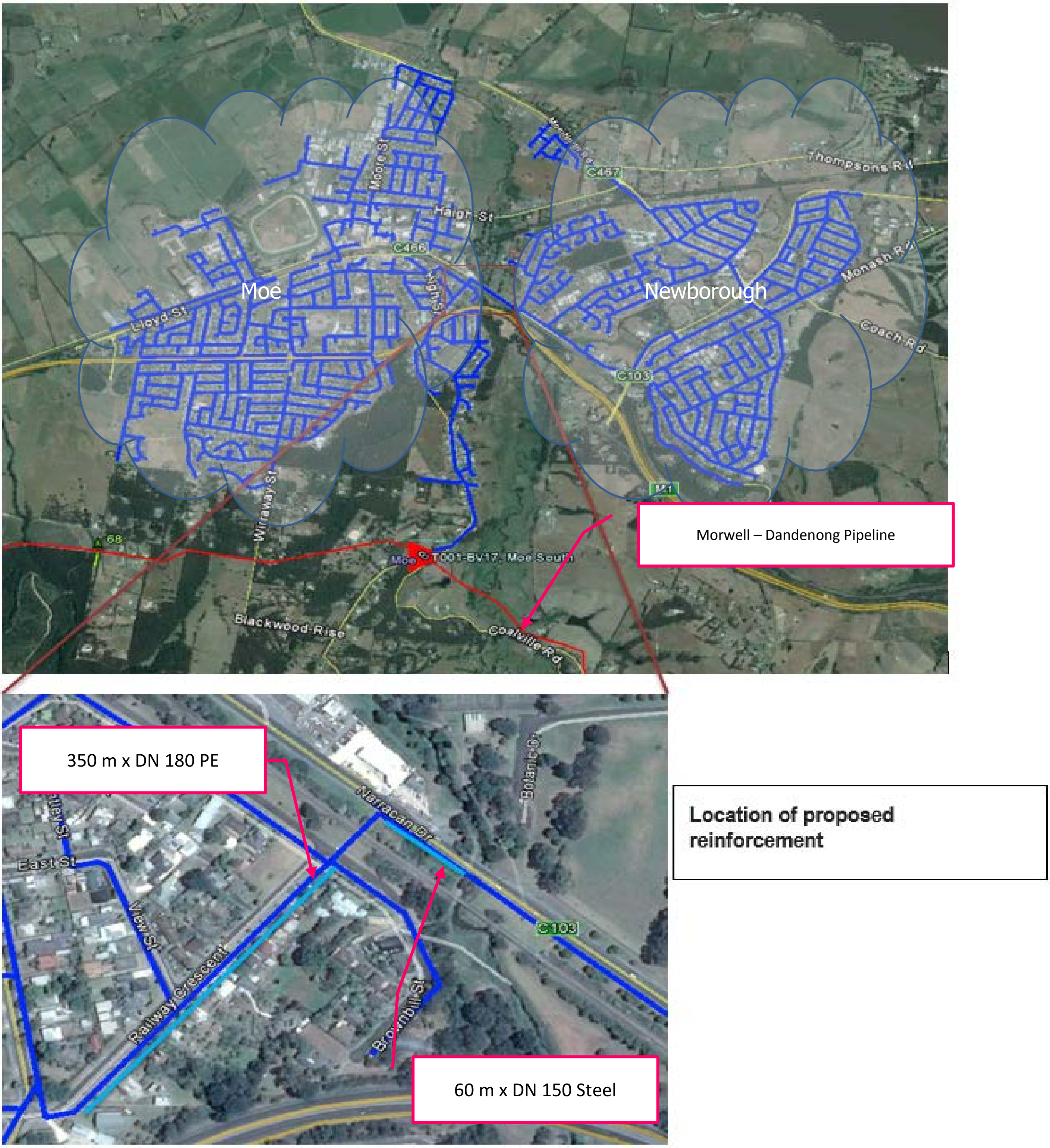
- *Prudent*: The expenditure is necessary to maintain and improve the safety and integrity of services, and to comply with regulatory obligations. It is also of a nature that a prudent service provider would incur.
- *Efficient*: The cost estimates for this project are based on actual costs for similar works that were awarded via competitive tender. The manner in which AGN intends to carry out the work (i.e. field work to be carried out by an external contractor that has demonstrated specific expertise in completing the installation of the assets in a safe and cost effective manner and that will be selected through a competitive tender) can also be considered efficient.
- *Consistent with good industry practice*: Complying with the obligations set out in the Code by carrying out the proposed reinforcement is consistent with accepted and good industry practice. So too is reducing the risk to human health and safety posed by gas outages to as low as reasonably practicable in a manner that balances cost and risk as required by AS 4645 (Gas Distribution Network Management).
- *Achieve the lowest sustainable cost of providing the service*: The scale of augmentation is designed to match the network requirements, balancing the objectives of minimising community disruption during construction and the need to revisit augmentation within a short time without overinvesting in the network. Proactively addressing emerging gas supply issues will avoid multiple reactive measures, thereby ensuring the lowest long-term sustainable cost for customers. Continuing to expand the Network ensures that operating costs are spread over an increasing number of customers, helping to drive down the average cost per customer.

The capex can therefore be considered consistent with rule 79(1)(a) of the NGR. The proposed capital expenditure is also consistent with 79(1)(b), because it is necessary to:

- *maintain and improve the safety of services (79(2)(c)(i))* – if more connections to the network occur without corresponding augmentation of the network, then the risk of transient gas outages and the associated risk to human health and safety will increase;
- *maintain the integrity of services (79(2)(c)(ii))* – if the minimum pressure of the network is not maintained through augmentation of the network then the integrity of services will be adversely affected; and
- *comply with a regulatory obligation (79(2)(c)(iii))* – AGN is required by the Code to maintain minimum pressures and to continue to connect new customers located in 'minor infill' areas.

Appendix A Network Overview

Figure A1: Moe HP Network Map



Appendix B Risk Assessment

Table B.1: Untreated Risk

		Health & Safety	Environment	Operations	Customer	Reputation	Compliance	Finance
Scenario 1 – Supply loss 100 to 1,000 customers from inadequate system pressure	Likelihood	*N/A*	*N/A*	*Occasional*	*Occasional*	*Occasional*	*Occasional*	*Occasional*
	Consequence	*N/A*	*N/A*	*Medium*	*Minor*	*Minor*	*Medium*	*Insignificant*
	Risk Level	*N/A*	*N/A*	*Moderate*	*Low*	*Low*	*Moderate*	*Low*
Scenario 2 – GIB incident from transient supply loss	Likelihood	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*
	Consequence	*Major*	*Minor*	*Minor*	*Minor*	*Major*	*Major*	*Medium*
	Risk Level	*Moderate*	*Negligible*	*Negligible*	*Negligible*	*Moderate*	*Moderate*	*Moderate*

Table B.2: Treated Residual Risk

		Health & Safety	Environment	Operations	Customer	Reputation	Compliance	Finance
Scenario 1 – Supply loss 1,000 to 10,000 customers from inadequate system pressure	Likelihood	*N/A*	*N/A*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*
	Consequence	*N/A*	*N/A*	*Medium*	*Minor*	*Minor*	*Medium*	*Insignificant*
	Risk Level	*N/A*	*N/A*	*Low*	*Negligible*	*Negligible*	*Low*	*Negligible*

Appendix C Detailed Cost Estimate

Table C.1: Detailed Cost Breakdown – 60 metres x DN150 Steel Main

	Item	Description	No Units	Units	Cost / Unit	Total Cost
Materials	**1**					
Line Pipe	1.1	PIPE,METALLIC:168.3MM OD,ERW,7.1MM WALL THK,12M LG,STL,3.275MM	60	m	$ 60	$ 3,600
Bends, Fittings, Tees etc	1.2	Bends, fittings, marker tape.	1	ea	$ 5,000	$ 5,000
Pipe Cartage costs	1.3	Cartage costs for 150ST	1	ea	$ 1,750	$ 1,750
						$ -
						$ -
Sub-total - Materials						**$ 10,350**
Construction	**2**					
Labour & Equipment	**2.1**					
Comdain Tie In	2.1.1	Tie In 100mm Railway Crossing	1	ea	$ 1,500	$ 1,500
Comdain Tie In	2.1.2	Tie In 150mm Moe River	1	ea	$ 1,500	$ 1,500
Standard Contractor Items	**2.2**					
Comdain Install	2.1.1	NW - Labour Hire Two Person Crew South East	40	hr	$ 122	$ 4,892
		NW - Tip Truck Up to 15 tonne Wet South East	40	hr	$ 138	$ 5,520
		NW - Crew Leader	40	hr	$ 120	$ 4,800.00
		Excavator Hire/Operator	40	hr	$ 125	$ 5,000.00
Welder	2.2.2	Welding of pipe/fittings	40	hr	$ 135	$ 5,400
		Living Away	1	ea	$ 1,000	$ 1,000
TDW	2.2.3	Tapping of 200 Tee	1	ea	$ 9,862	$ 9,862
Traffic Management	2.2.4	Narracan Drive	6	Day	$ 1,500	$ 9,000
						$ -
Sub-total - Construction						**$ 48,474**
Specialist Services	**3**					
Environmental & CH	**3.1**					
Environmental	3.1.1	Site assessments due to Moe River	1	ea	$ 40,000	$ 34,000
Others	**3.2**					
Survey	3.2.1	Buliding Line confirmations/Installations	1	ea	$ 1,000	$ 1,000.00
Underground locations	3.2.2	NDT provings	2	Day	$ 1,500	$ 3,000.00
	3.3.3	Reinstatement soil,seed,warnings signs	60	m	$ 18	$ 1,080.00
Sub-total - Specialist Services						**$ 39,080**
Project Management and Design	**4**					
Labour	**4.1**					
						$ -
Sub-total - PM and Design						**$ -**
Other	**5**	Insert other items as applicable				
Other authority approvals	4.1.1	Vic Roads Road opening permits	1	ea	$ 600	$ 600
Sub-total - Other						**$ 600**
PROJECT TOTAL						**$ 98,504**

Table C.2: Detailed Cost Breakdown – DN180 PE Main

	Item	Description	No Units	Units	Cost / Unit	Total Cost
Materials	**1**					
Line pipe	1.1	Pipe Plastic DN 180, 12M LG Series 2 PE 100	360	m	$ 30	$ 10,800
Valves	1.2	150mm Steel Audco valve	1	ea	$ 3,000	$ 3,000
Valves		100mm Steel Audco valve	1	ea	$ 2,000	$ 2,000
Line Pipe		PIPE,METALLIC:114.3MM OD,ERW,6.02MM WALL THK,12M L(	36	m	$ 32	$ 1,152
Line Pipe	1.3	PIPE,METALLIC:168.3MM OD,ERW,7.1MM WALL THK,12M LG,STL,3.275MM	36	m	$ 55	$ 1,980
Bends, Fittings, Tees etc	1.4	Bends, fittings, marker tape.	1	ea	$ 3,786	$ 3,786
Pipe Cartage costs	1.5	Cartage costs for 180PE , 150ST, 100ST	3	ea	$ 1,750	$ 5,250
						$ -
						$ -
Sub-total - Materials						**$ 27,968**
Construction	**2**					
Labour & Equipment	**2.1**					
Comdain Tie In	2.1.1	Tie In 100mm Railway Crossing	1	ea	$ 1,500	$ 1,500
Comdain Tie In	2.1.2	Tie In 150mm High St	1	ea	$ 1,500	$ 1,500
Standard Contractor Items	**2.2**					
Installation 180PE	2.2.1	NW-Mlay Single Tench Mains Extension >125mm<=180PE Warragul B	360	m	$ 150	$ 54,000
Traffic Management	2.2.2	Princes Highway crossing	3	Day	$ 1,500	$ 4,500
Bores	2.2.3	High Street Moe HDD	1	ea	$ 5,000	$ 5,000
Welder	2.2.4	Welding of pipe/fittings	24	hr	$ 135	$ 3,240
		Living Away	1	ea	$ 1,000	$ 1,000
TDW	2.2.5	Tapping of 200 Tee	1	ea	$ 9,862	$ 9,862
Others	**2.3**					
						$ -
Sub-total - Construction						**$ 80,602**
Specialist Services	**3**					
Environmental & CH	**3.1**					
Environmental	3.1.1	Site assessments etc	1	ea	$ 15,000	$ 15,000
Others	**3.2**					
Survey	3.2.1	Buliding Line confirmations/Installations	1	ea	$ 1,000	$ 1,000.00
Underground locations	3.2.2	NDT provings	3	Day	$ 1,500	$ 4,500.00
						$ -
Sub-total - Specialist Services						**$ 20,500**
Project Management and Design	**4**					
Labour	**4.1**					
						$ -
Sub-total - PM and Design						**$ -**
Other	**5**	Insert other items as applicable				
						$ -
Sub-total - Other						**$ -**
PROJECT TOTAL						**$ 129,070**

Business Case – Capex V103

H79 Wallan

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	Keith Lenghaus, *Asset Planning Manager*
Approved By	Andrew Foley, *General Manager Victorian Networks*

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	The Wallan high pressure (HP) network (H79) supplies gas to over 7,000 customers in the townships of Wallan. Continuing residential growth is expected to reduce pressures within the network to below the recommended minimum considered essential to maintain a safe and reliable supply of gas to consumers. Operating below the recommended minimum pressure could result in the loss of several hundred consumers. In circumstances where there is a momentary loss of supply there is a risk that this could lead to a gas in building incident causing major damage and or life threatening injuries. The risk associated with gas outage has been assessed as 'moderate' Failure to augment the network as set out in this business case would not be consistent with AGN's obligations to: • Maintain network pressures above the distribution supply point minimum specified in the Victorian Distribution System Code (Code). Failure to do so would be considered a breach of AGN's license condition. • Maintain and improve the safety of services to consumers – Failure to do so could result in serious injury or damage to property • Maintain a reliable supply to consumers – Failure to do so would incur Guaranteed Service Level (GSL) payments and have potential, in the long term, to harm the reputation of natural gas as a reliable energy source promoting consumers to switch to alternatives. • Connect customers that are within minor or infill areas as required by the Code – Failure to do so would be considered a breach of AGN's license condition Viewed in this way augmentation of the Wallan network is required to: • comply with the regulatory obligations set out in the Code; and • maintain and improve the safety and reliability of services.
Options Considered	The following options have been considered to address the growth in the Wallan HP network: 1 Option 1: Allow ongoing growth to decrement capacity to the extent that supply loss becomes a more regular event. 2 Option 2: Control the amount of additional load of the network by either limiting

	connections or implement demand management (turn off during peak periods) 3 Option 3: Augment the network by installing 200 metres DN150 steel trunk main 4 Option 4: Augment the network via a number of interconnections totaling 870 metres 5 Option 4: Defer augmentation into the following regulatory period Options 1, 2, and 5 are not considered feasible given the regulatory obligations to maintain a safe and reliable supply of gas to consumers. Options 3 and 4 will support load growth in the network while maintaining a safe and reliable gas supply to existing consumers, Option 3 is more cost effective.
Proposed Solution	Option 3 has been selected because it is the most cost effective way to comply with regulatory obligations set out in the Code to maintain a safe and reliable supply of gas to customers. This option reduces the risk from 'medium' to 'low' consistent with obligations under Australian Standard AS/NZ 4645.
Estimated Cost	The forecast capital expenditure (capex) over the next AA period for Option 3 is $487.8 ($000, 2016).
Consistency with the National Gas Rules (NGR)	The augmentation complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because: • it is necessary to maintain and improve the safety of services and maintain the integrity of services and comply with a regulatory obligation (rules 79(2)(c)(i) (ii) and (iii)); 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	AGN has undertaken a comprehensive stakeholder engagement program to better understand the needs and values of our stakeholders and customers. During this engagement, customers told us that they value current standards of reliability and are supportive of initiatives that maintain their reliability and improve the safety of the network. Implementation of this initiative will allow AGN to maintain the safety of the network while continuing to provide a highly reliable supply of natural gas to our customers. More information detailing the results of AGN's stakeholder engagement program is provided in Chapter 5 of the Access Arrangement Information document.

1.3. Background

1.3.1. General

The Wallan high pressure (HP) network (H79) provides gas to about 4,000 residential customers in the township of Wallan, located approximately 40 km north of the Melbourne CBD, and is part of the northern exurban growth corridor.

The network is supplied from a city gate station is located on the eastern side of Wallan, fed via the Victoria NSW Interconnect. An overview map of the network is provided in Appendix A.

Capacity modelling[1] has confirmed that ongoing residential growth in the area will reduce network pressures to below the minimum required to sustain a safe and reliable supply of gas. Modelling has highlighted the need to duplicate the existing trunk main supplying the Wallan township.

The remainder of this section details our obligations and explains why there is a need to deliver augmentation of the Wallan network over the next AA period.

1.3.2. Regulatory Obligations and the Wallan Network

1.3.2.1. Obligation to Maintain Supply Pressure

Under the Code[2], AGN has a regulatory obligation to use all reasonable endeavours to:

> *"…ensure the minimum pressure is maintained at the distribution supply point.[3]"*

This requirement covers both distribution and transmission pipelines. In the Wallan network, the minimum Distribution System Pressure required by the Code is 140 kPa.[4] Over the next AA period fringe pressures in Wallan are expected to fall below the recommended design minimum commencing from the 2021 winter (refer to Table 1.4 for details).

1.3.2.2. Obligation to Connect

In addition to having an obligation to maintain supply pressures, AGN also has an obligation under the Code to connect customers that are within the minor infill extension areas.[5] Specifically, clause 3.1(c) of the Code states that:

> *"A Distributor must connect the gas installation of a customer that resides within the minor or infill extension area on fair and reasonable terms and conditions"*

The growth forecast discussed in the Section 1.4.2 is based on projected dwelling construction within areas that would be considered minor or infill extension under the Code.

1.3.2.3. Guaranteed Service Levels

In the event that interruptions to supply occur, depending on the circumstances and duration of interruption AGN may be required to make a Guaranteed Service Level (GSL[6]) payment to each affected customer.

[1] H79 2015 Network Capacity Review

[2] The Code has been developed by the Victorian Essential Services Commission and applies to all distributors that hold a distribution licence. The Code sets out the minimum standards for the operation and use of the distribution system, which include, amongst other things, minimum standards for connections and augmentations. As stated in the notes to section 3 of the Code, clause 4 of AGN's Gas Distribution Licence requires compliance with this Code.

[3] Schedule 1 Part A of the Code.

[4] This obligation is set out in Schedule 1 of the Code.

[5] The term 'minor and infill extension area' is defined in clause 2.1(f) of the Code as an area that is up to 1 km radially from the nearest part of the distribution system main.

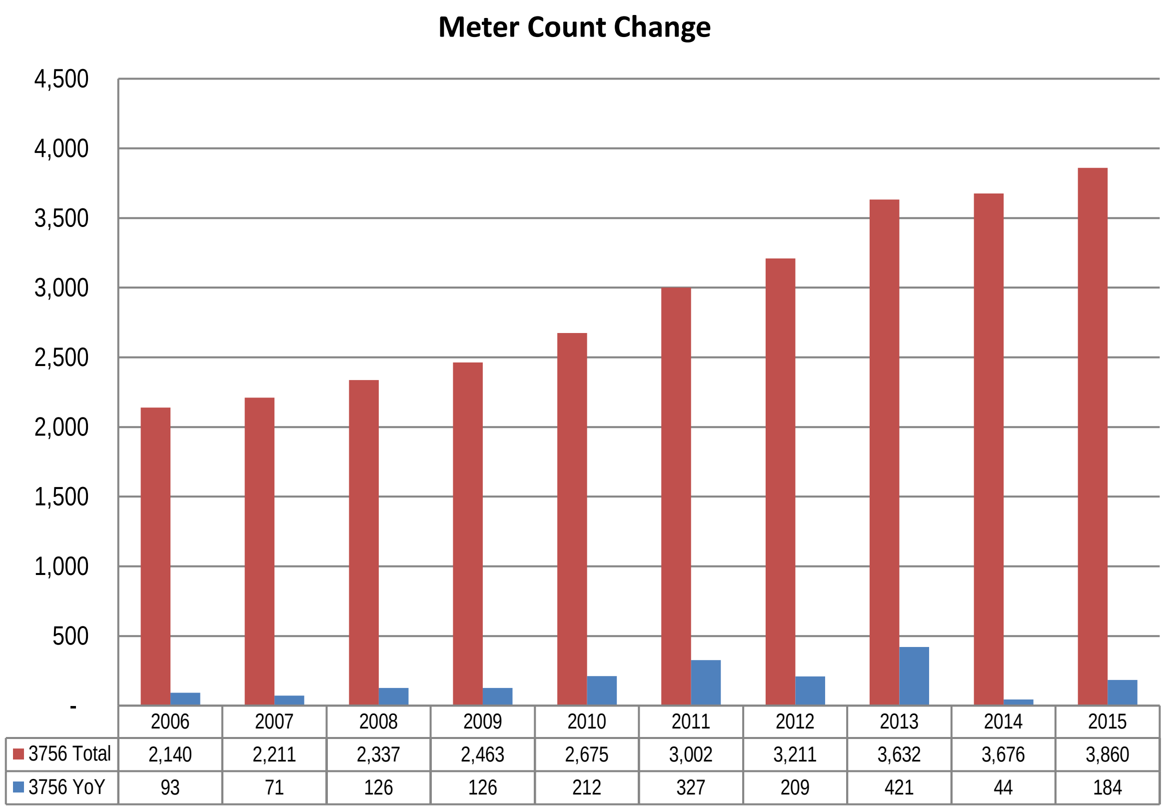
[6] The Guaranteed Service Level (GSL) payment is intended to ensure that customers are compensated if an energy distribution company does not meet certain minimum performance standards. The amount payable and the conditions under which a GSL payment is triggered are set out in Part E of the Code. For supply interruptions, repeated or lengthy interruptions would incur a GSL of between $150 and $300 per affected customer. Refer ESC website for a copy of the Code: http://www.esc.vic.gov.au/document/energy/26123-gas-distribution-system-code-2/

1.4. Key Drivers and Assumptions

1.4.1. Historic Growth

Figure 1.1 summarises the historic growth in Wallan (postcodes 3756) served by the Wallan HP network.

Figure 1.1: Meter Count Change



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
3756 Total	2,140	2,211	2,337	2,463	2,675	3,002	3,211	3,632	3,676	3,860
3756 YoY	93	71	126	126	212	327	209	421	44	184

The five year average from 2011 to 2015 is 237 connections per year.

1.4.2. Future Demand

Table 1.3 summarises the criteria and assumptions used to establish demand in the Wallan HP network over the next Access Arrangement (AA) period.

Table 1.3: Growth Assumptions

Criteria/Assumption	Basis
Average annual growth in net new tariff V customer connections will continue to grow at an average of 200 connections per year	This is based on a review of annual projected growth in dwellings from a number of sources[7] . This rate is slightly below the historic five year average rate of 240.
Tariff D load added as needed	Tariff D Loads arrive unpredictably, and growth in D load has not been allowed for in this analysis. Tariff D load growth will be addressed on an as needed basis, with cost of connection assessed at the time of enquiry.
Average demand per tariff V customer of 1.1 m^3/hour	The calculated ratio of tariff V design load to tariff V meter connection numbers in the Wallan network.
Penetration rate of 91%	The ratio of active connections to completed homes has been assessed for the area and found to be 91%. It has been assumed that the historically observed rate will continue, at least over the forecast horizon for this business case.

1.4.3. Customer Impact

Continued growth in Wallan is expected to reduce network pressures at various locations within the Wallan network over the next AA period. Table 1.4 summarises the impact on network pressures at the network fringe.

Table 1.4: Wallan Network Minimum Pressure (kPa)

Winter Minimum Pressure	2017	2018	2019	2020	2021	2022
Wallan minimum pressure	156	129	98	59	5	0
Total Customers	4,083	4,286	4,488	4,690	4,893	5,095
Customers < 140 kPa	0	139	425	628	1,022	1,455
Customers < 0 kPa	0	0	0	0	0	881

The analysis shows that network pressures are expected to drop below the required minimum from about 2018 and continue to fall across the network over the next AA period.

The final two rows of this table set out:

- the number of customers that could be affected by the reduction in pressure below the 140 kPa Code requirement and could therefore be at risk of a transient gas outage[8]; and

[7] Wallan Forecast.id report, 11th April 2016 http://forecast.id.com.au/mitchel , Wallan residential development plan and Wallan structure plan http://www.wallan3756.com.au/welcome-wallan-3756 ; plus various subdivision plans for the Wallan area.

- the number of customers that are at risk of receiving no gas at all if network pressures fall below atmospheric pressure.

It is estimated that over 1,400 customers could be impacted by poor system pressures by 2022 resulting in:

- transient and unpredictable interruptions to gas supply, occurring at increasing frequency year on year; and
- the potential for an outage to result in release of un-combusted natural gas from a burner that was extinguished during the outage but remained open up to the recovery of gas supply, leading to natural gas accumulation in a confined space followed by fire, explosion or asphyxiation.

Further detail on these risks can be found in Section 1.5

Taking action to address these issues is consistent with the findings of our stakeholder engagement program which found strong support from workshop participants for AGN to undertake key projects like this one to ensure reliability to existing customers is maintained, and which are necessary investments arising from the demands of ongoing customer connection growth.

1.4.4. Summary

Continued residential growth in the Wallan area will require the capacity of the Wallan HP network to be augmented during the next AA period. This will be necessary to:

- maintain minimum gas pressures, as set out in the Gas Distribution Code, necessary for a safe and reliable supply of gas to existing consumers;
- avoid GSL payments and relight costs associated with gas outages; and
- meet AGN's obligation to supply 'infill' growth.

1.5. Risk Assessment

A risk assessment of the following scenarios has been carried out in accordance with the APA Risk Policy and Risk Matrix.

Scenario 1. Organic Tariff V growth has reduced the Wallan HP network pressure to below the recommended minimum during the winter peak demand period resulting in the loss of supply to up to 1,000 customers. This is considered an 'occasional' event as per the APA Risk Policy.

Scenario 2. Network pressure at the extremity of the HP network drops below the recommended minimum resulting in a momentary loss of supply to a number of consumers. This in turn causes a flame out on an appliance (cook top) and the subsequent return of supply results in a gas in building (GIB) incident that remains unnoticed by the occupant resulting in a fire or explosion. This is considered to be a 'rare' event as per the APA Risk Policy

[8] The term 'transient gas outage' is used in this context to refer to the situation where tariff V gas demand outstrips the network's supply capability for a relatively short period of time. This could occur on a gas day if peak demand is too large and the pressure at the end of the network drops to such a low level that customers in the area of low pressure experience an interruption in supply. Once the peak load starts to fall, the network pressures will start to recover and the supply of gas will return to these customers.

The table below summarises the risks associated with these three scenarios. A detailed breakdown of the risk assessment has been provided in Appendix B.

Table 1.5: Risk Rating

Risk Area	Untreated Risk Scenario 1	Untreated Risk Scenario 2
Health and Safety	N/A	Moderate
Environment	N/A	Negligible
Operational	Moderate	Negligible
Customers	Low	Negligible
Reputation	Low	Moderate
Compliance	Moderate	Moderate
Financial	Low	Moderate
Untreated Risk Rating	**Moderate**	**Moderate**

The risk associated with the loss of supply has been assessed as 'moderate'.

While there is the potential for an outage to result in the release of un-combusted natural gas from a burner, leading to a fire, explosion the risk is also considered 'moderate' as the likelihood is rare.

AGN has an obligation under its license conditions to assess its asset risks and reduce any high or medium risks to 'low' or 'negligible' and if not 'as low as reasonably practicable'.

1.6. Options Considered

AGN has considered the following options to address the network capacity issues outlined above.

1. Option 1: Allow ongoing growth to decrement the Wallan network capacity to the extent that supply loss becomes a more regular event.
2. Option 2: Control the amount of additional load on the network by either limiting connections or implement demand management (turn off during peak periods).
3. Option 3: Augment the network by duplicating the trunk main feeding Wallan
4. Option 4: Augment the network via a number of interconnections within the Wallan network
5. Option 5: Defer augmentation into the following regulatory period

Further detail on these options is provided below.

1.6.1. Option 1 – Accept increasing risk of supply loss

Under this option, AGN will continue to accept network connections (as it is required to do under the Code) but do nothing to address the effect on the network design minimum pressures.

1.6.1.1. Cost/Benefit Analysis

The benefit of this option is that it does not give rise to any upfront capital costs. This option would, however, result in AGN contravening its regulatory obligation to use all reasonable endeavours to

> *"ensure the minimum pressure is maintained at the distribution supply point"*

and as a result the network design minimum pressures will be breached by an increasing amount and frequency each year, impacting an increasing number of customers in the Wallan network.

This option does not address:

- *Reduced reliability and security of supply* – Connected customers towards the fringe of the network will not have 'un-fettered' use of the gas supply that they have paid for. Not all customers will be impacted equally, creating an inequitable supply privilege gradient where customers closer to the gate get a better level of service at the expense of customers at the network fringe. This is inconsistent with the intent of the gas regulatory framework (including the Access Arrangement framework), which is designed to ensure that all customers are treated equitably and are provided with access on a non-discriminatory basis.
- *Potential safety issues with the network* – A gas network that is not operating correctly or predictably is an unsafe network. A transient loss of gas gives rise to the risk of the release of un-combusted gas, as operating gas appliances do not necessarily respond to loss of gas by automatically turning off. As free gas is released there is the potential for it to collect in a confined space and eventually catch fire or explode, which poses a risk to human health and safety and property. Doing nothing to address the risk of gas intrusion is inconsistent with Australian Standard AS4645 (Gas Distribution Network Management), which requires that this must be managed to 'low' or 'negligible' and if not to 'as low as reasonably practicable'.
- *Increased Opex as result of GSL payments and relights* - The increased risk of an outage under this option also increases the likelihood that AGN will have to make GSL payments (lengthy interruptions incur a charge of $300 per affected property) and incur costs relighting customers, with the costs of the order of $40 per relight.

Given the risks posed by this option and the fact that it would result in AGN failing to comply with its regulatory and code obligations this option is not considered or prudent or viable option.

1.6.2. Option 2 – Control/Limit Additional Load

Under this option AGN would maintain the current network configuration without augmenting the network and limit network connections and or reduce consumption during peak periods. This would be aimed at ensuring pressures at the extremity of the Wallan HP network are maintained above the required minimum ensuring that a safe and reliable supply can be maintained.

1.6.2.1. Cost/Benefit Analysis

Like Option 1, the benefit of this option is that it does not give rise to any upfront capital costs. However, this option is not considered prudent or viable for the following reasons:

- Limiting future connections would contravene AGN's regulatory obligation under the Code to connect customers that are with the minor or infill extension areas
- Existing contracts have not been structured to allow for 'turndown' of supply during peak periods. From a practical point of view it would be impossible to 'predict' capacity shortfalls in the network with sufficient lead time to allow major consumers to reduce their consumption by shifting to alternative energy sources or curtailing operations.

No further consideration has therefore been given to this option.

1.6.3. Option 3 – Trunk Main Augmentation

The third option that AGN has considered is to augment the Wallan HP network by duplicating a section of the HP trunk main feeding Wallan (refer to Appendix A Figure A.1 for location details). The scope and timing of this augmentation is summarized in Table 1.6 below.

Table 1.6: Network Trunk Augmentation

Year	Infrastructure	Cost Estimate ($,000 2016)
Mains Infrastructure		
2018	80 metres x DN63 PE - King Street	67.4
2019	80 metres x DN63 PE - Franklin Close	67.4
2020	200 metres x DN150 Steel main duplicating the existing main across the Hume Freeway	353
	Total Capital Expenditure	**487.8**

1.6.3.1. Cost/Benefit Analysis

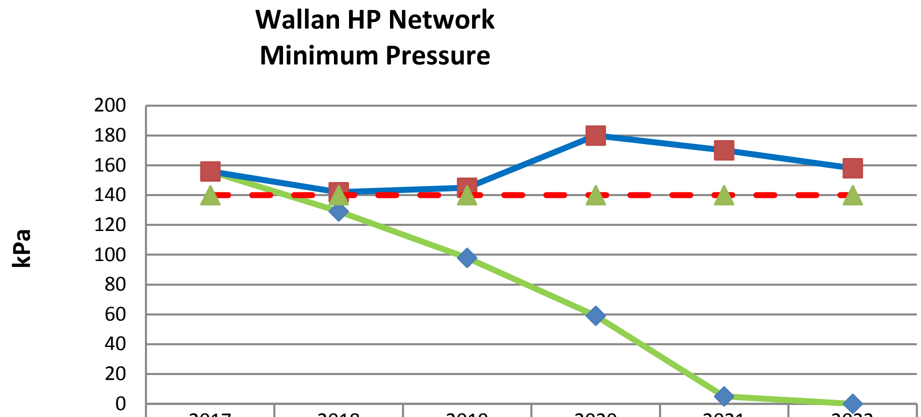
The capital cost of this Option 3 is $ 487.8 ($'000, 2016). Refer to Appendix C for a detailed cost breakdown.

The benefit of this option is that it reduces risk of gas outage from 'moderate' to 'low' (refer to Appendix B), and in doing so:

- ensures compliance with AGN's regulatory obligations under the Code by:
  - ensuring that minimum network pressures are maintained at distribution supply points and, in so doing, maintain the integrity of services; and
  - allowing new connections to occur (as required by the Code), without risk to gas supply at the network fringe;
- maintain the safety of services by reducing the risk of gas intrusion and the associated risks to human health and safety to as low as reasonably practicable, consistent with Australian Standard AS4645; and
- reduce the likelihood that AGN will have to make GSL payments and incur costs in relighting customers if there is an outage.

Figure 1.2 summarises the expected minimum pressure at fringe point locations within the Wallan HP network given the proposed augmentation.

Figure 1.2: Network Pressure – Post Augmentation



	2017	2018	2019	2020	2021	2022
Without Augmentation	156	129	98	59	5	0
Option 3 Augmentation	156	142	145	180	170	158
Required Minimum	140	140	140	140	140	140

The proposed duplication will support forecast load growth at least through to the end of 2022.

1.6.4. Option 4 – Network Augmentation (various)

This option considers a number of interconnections and duplications that, in aggregate, provide about same capacity improvement as Option 3. These have been summarised in Table 1.7 below

Table 1.7: Network Augmentation (various)

Year	Infrastructure	Cost Estimate ($,000 2016)
Mains Infrastructure		
2018	80 metres x DN63 PE - King Street	67.4
2019	80 metres x DN63 PE - Franklin Close	67.4
2020	290 metres x DN180 PE – William Street	273.4
2020	310 metres x DN125 PE – Dudley Street	244.1
2021	100 metres x DN125 PE – Adrian Circuit	121.6
2021	20 metres x DN125 PE – Duke Street	42.3
2021	70 metres x DN63 main - Duke Street	77.2
	Total Capital Expenditure	**893**

1.6.4.1. Cost/Benefit Analysis

The capital cost of this option is $ 893 ($’000, 2016). Refer to Appendix C for a detailed cost breakdown.

This option provides a similar improvement in system pressure as Option 3 reducing the risk of gas outage from 'moderate' to 'low' and in doing so:

- ensures compliance with AGN's regulatory obligations under the Code by:
  - ensuring that minimum network pressures are maintained at distribution supply points and, in so doing, maintain the integrity of services; and
  - allowing new connections to occur (as required by the Code), without risk to gas supply at the network fringe;
- maintains the safety of services by reducing the risk of gas intrusion and the associated risks to human health and safety to as low as reasonably practicable, consistent with Australian Standard AS4645; and
- reduces the likelihood that AGN will have to make GSL payments and incur costs in relighting customers if there is an outage.

1.6.5. Option 5 – Defer Augmentation

Deferring the augmentation into the following regulatory period (2023 – 2027) has been considered. This would require the acceptance of a 'moderate' risk of gas outage for several years. AGN would be non-compliant with its obligations to maintain a safe and reliable supply to consumers for the period of delay.

The cost of this option would effectively see Option 3 escalated to the future year of execution.

There would be a small cost saving (arising from the time cost of money) to customers from deferring the work. This cost saving is considered to be immaterial compared to being non-compliant, while posing an increased safety and supply risk and being inconsistent with the prudent and efficient operation of the network.

Given AGN's obligations, deferral was not considered a prudent or efficient option.

1.7. Summary of Cost/Benefit Analysis

Table 1.8 below provides a summary of costs, risks and benefits associated with the five options.

Table 1.8: Summary of Cost/Benefit Analysis

Option	Benefits	Costs/Risks
Option 1	Avoids up front capital expenditure.	No capital costs GSL payments of up to $300 per customer plus $40 per customer for relight in event of a gas outage. AGN would fail to comply with its regulatory obligations under the Code to use all reasonable endeavours to ensure safe and reliable supply of gas to consumers. Residual risk is 'moderate' Not a prudent option
Option 2	Avoids up front capital expenditure.	No capital costs

		Impractical to implement - contracts do not allow for demand management. AGN would fail to comply with its obligation under the Code to connect customers. Not a prudent option
Option 3	Ensures AGN complies with the pressure and connection provisions in the Code. Reduces the risk of gas outages and the associated risks to human health and safety to as low as reasonably practicable. Maintains the reliability of supply to existing consumers.	Capital costs $487.8 ($'000, 2016) to duplicate a section of trunk main. This the recommended option based on reducing risk from 'moderate' to 'low' at the lowest cost.
Option 4	Ensures AGN complies with the pressure and connection provisions in the Code. Reduces the risk of gas outages and the associated risks to human health and safety to as low as reasonably practicable. Maintains the reliability of supply to existing consumers.	Capital costs $826k ($'000, 2016). Residual risk is 'low'
Option 5	Deferral creates time value of money savings	No capital costs in the next regulatory period AGN would fail to comply with its regulatory obligations under the Code to use all reasonable endeavours to ensure safe and reliable supply of gas to consumers. Residual Risk is 'Moderate' Not considered a prudent option

1.8. Proposed Solution

1.8.1. What is the Proposed Solution?

The proposed solution is Option 3, which will involve duplicating sections of the trunk main feeding Wallan.

The scope, timing and costs are summarised in Section 1.6.3.

1.8.2. Why are we proposing this solution?

Option 3 has been selected because:

- The project is required to comply with regulatory obligations under the Code to maintain a safe and reliable supply of gas to customers.
- It is the most cost effective solution – The proposed augmentation represents the minimum amount of augmentation necessary to sustain growth over the next regulatory period. Depending on growth further 'staged' augmentation will be necessary in the following period.

- It is a low risk, technically simple and proven solution. Laying pipe in the ground provides a known capacity improvement for an expenditure amount that can be relatively accurately quantified. The risk of delivery is minimal, on either a time or budget basis.

1.8.3. Stakeholder Engagement

Overall, our customers told us that they value current standards of reliability and are supportive of initiatives that maintain their reliability and improve the safety of the network with the majority of participants prepared to pay to support the maintenance of the existing level of reliability of the network, with the understanding that upgrades to meet population growth are necessary investments for the supply of gas for Victorian residents into the future.

Projects that support reliability received support from 86% of workshop participants, behind only awareness of AGN assets, ongoing mains replacement program and bushfire preparedness when ranked in order of importance.

Figure 1.3: Stakeholder Engagement Results

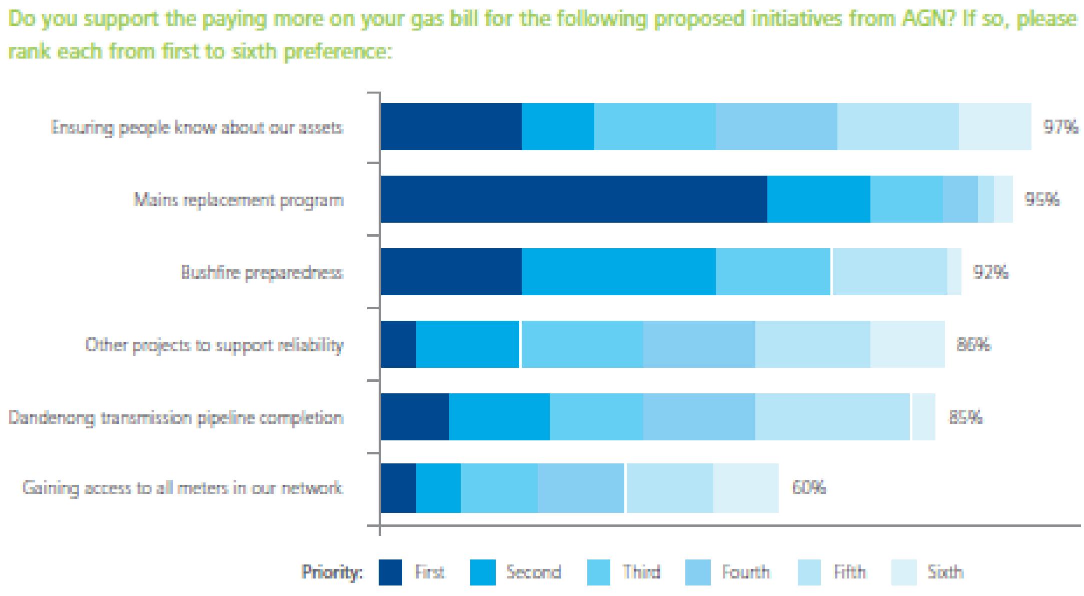


Figure 4: Total workshop support of AGN's proposed initiatives, broken down by preference rank

1.8.4. Forecast Cost Breakdown

Table 1.9 below provides a summary of the capex that is forecast to be incurred in the next AA period under Option 3, which has been estimated on the basis of the following assumptions:

- *Materials* – Where possible, the cost of the materials required is based on the price achieved for comparable works completed elsewhere in the network. Where a suitable cost estimate from outcomes is unavailable, the material cost is estimated from recent quotes received for other similar works and previous cost experience.
- *Labour* – where possible the labour costs have been based on the unit rate achieved as the result of competitive tender between external contractors. This is assumed to reflect the best efficient delivery cost achievable. For specialist services, the cost estimate is derived from the cost of basic due diligence for similar projects.

- *Project Timing* – projects have been sequenced to ensure manageable project delivery targets while avoiding breaching minimum pressures under design conditions. Where design condition assessment shows pressures below the Code minimum network management will ensure that supply is maintained.

A more detailed cost breakdown can be found in Appendix C.

Table 1.9: Capex Split ($000, 2016)

	2018	2019	2020	2021	2022	Total
Land	-	-	-	-	-	-
Materials	-	11	-	-	-	11
Labour	-	139	203	-	-	342
Total	-	**150**	**203**	-	-	**353**

1.8.5. Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN considers the forecast capex for this project to be:

- *Prudent* – The expenditure is necessary to maintain and improve the safety and integrity of services, and to comply with regulatory obligations. It is of a nature that a prudent holder of a Gas Distribution License would incur.
- *Efficient* – The cost estimates for this project are based on actual costs for similar works that were awarded via competitive tender. The field work will be carried out by the external contractor, selected via competitive tender, who has demonstrated specific expertise in completing the installation of the assets in a safe and cost effective manner.
- *Consistent with accepted good industry practice* – the construction projects will make use of standard competitive tendering to ensure that market rates are achieved. Standard processes and procedures in design, construction and documentation will ensure that the asset will meet performance and maintenance targets over its design life. The Victorian Gas Distributors all operate under the requirements of the Victorian Gas Distribution Code, and compliance with the Code is good industry practice.
- *Achieves the lowest sustainable cost of delivering pipeline services* – the scale of augmentation is designed to match the network requirements, balancing the objectives of minimising community disruption during construction and the need to revisit augmentation within a short time without overinvesting in the network. Proactively addressing emerging gas supply issues will avoid multiple reactive measures, thereby ensuring the lowest long term sustainable cost for customers. Continuing to expand the Network ensures that operating costs are spread over an increasing number of customers, helping to drive down the average cost per customer.

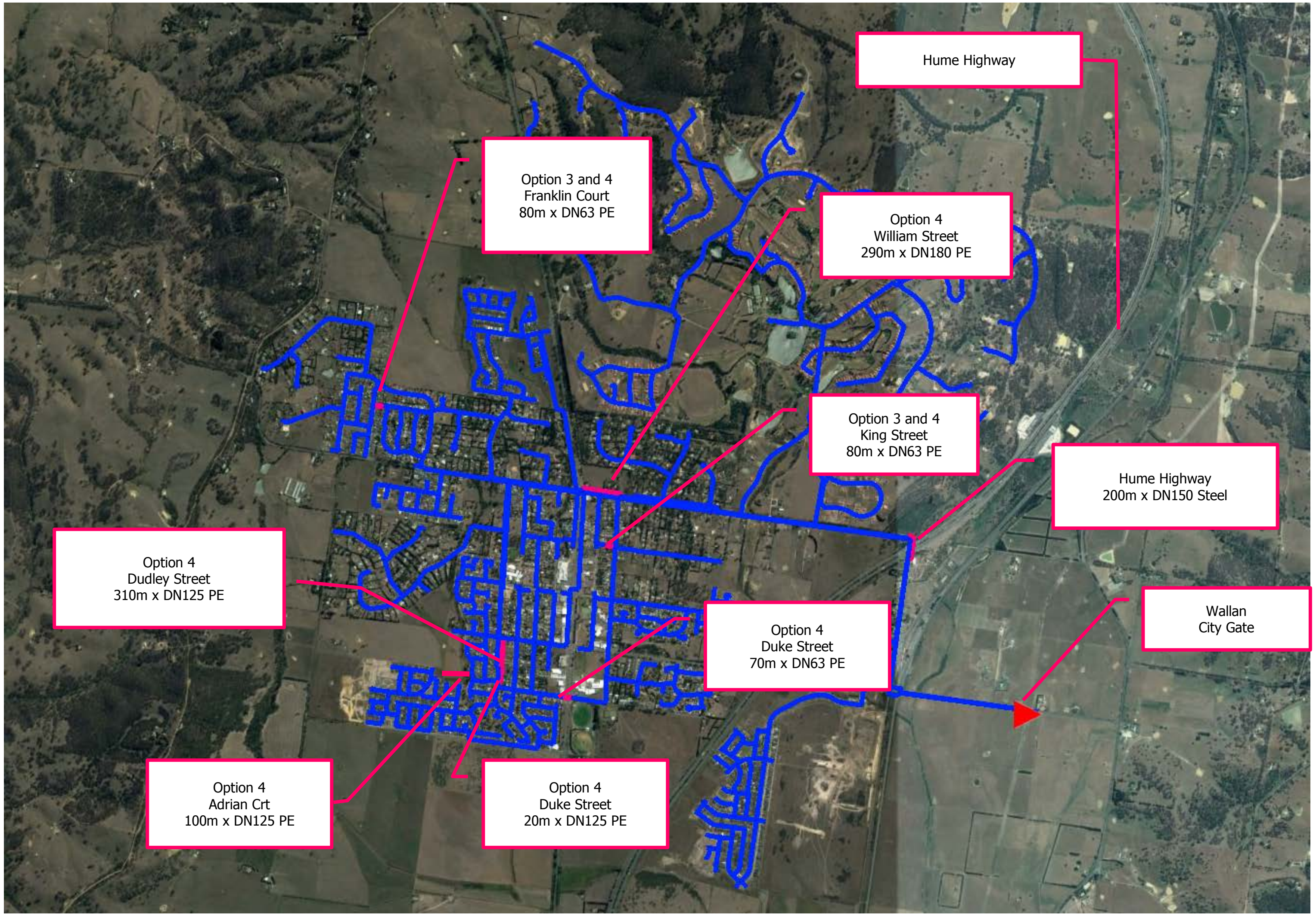
The capex can therefore be viewed as being consistent with rule 79(1)(a) of the NGR.

The proposed capex is also consistent with rule 79(1)(b), because the expenditure is necessary to:

- *maintain and improve the safety of services (rule 79(2)(c)(i))* - if more connections to the network occur without corresponding augmentation of the network, then the risk of transient gas outages and the associated risk to human health and safety will increase;
- *maintain the integrity of services (rule 79(2)(c)(ii))* - if the minimum pressure of the network is not maintained through augmentation of the network then the integrity of services will be adversely affected; and
- *comply with a regulatory obligation (79(2)(c)(iii))* – AGN is required by the Code to maintain minimum pressures and to continue to connect new customers located in 'minor infill' areas of the Wallan network.

Appendix A Network Overview

Figure A.1: Wallan Network Map



Appendix B Risk Assessment

Table B.1: Untreated Risk

		Health & Safety	Environment	Operations	Customer	Reputation	Compliance	Finance
Scenario 1 – Supply loss 1,000 to 10,000 customers from inadequate system pressure	Likelihood	*N/A*	*N/A*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*
	Consequence	*N/A*	*N/A*	*Significant*	*Minor*	*Medium*	*Medium*	*Minor*
	Risk Level	*N/A*	*N/A*	*High*	*Low*	*Moderate*	*Moderate*	*Low*
Scenario 2 – GIB incident from transient supply loss	Likelihood	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*
	Consequence	*Major*	*Minor*	*Minor*	*Minor*	*Major*	*Major*	*Medium*
	Risk Level	*Moderate*	*Negligible*	*Negligible*	*Negligible*	*Moderate*	*Moderate*	*Moderate*

Table B.2: Treated Residual Risk

		Health & Safety	Environment	Operations	Customer	Reputation	Compliance	Finance
Scenario 1 – Supply loss 1,000 to 10,000 customers from inadequate system pressure	Likelihood	*N/A*	*N/A*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*
	Consequence	*N/A*	*N/A*	*Minor*	*Minor*	*Insignificant*	*Medium*	*Insignificant*
	Risk Level	*N/A*	*N/A*	*Negligible*	*Negligible*	*Low*	*Low*	*Negligible*

Appendix C Detailed Cost Estimate

Table C.1: Option 3 – Freeway Crossing Cost Estimate

	Capital Projects - Project Cost Estimate			
Project	Wallan Reinforcement Options			
Prepared by	Steven Crocker			
Date	26/08/2016			
Revision	A			
Scope of works	2019: R2 Duplication of Hume Hwy Crossing			
	Description	**Total Qty**	**Unit Rate**	**Total rate**
LabourCost				
Mainslaying	200m x 150mm OD steel pipe	1	310,015.00	310,015.00
	PM Allowance	1	32,000.00	32,000.00
				0.00
				0.00
				0.00
				0.00
				0.00
				0.00
Sub-total				342,015.00
Materials				
Line pipe	150mm OD steel pipe	200	51.26	10,252.00
Fitting	Elbows, Tees, & Caps	1	500.00	500.00
Consumables	Warning tape, consumables etc	1	200.00	200.00
				0.00
				0.00
				0.00
Sub-total				10,952.00
Environmental				
				0.00
				0.00
Sub-total				0.00
Detailed Design				
				0.00
				0.00
				0.00
				0.00
Sub-total				0.00
Direct Cost				352,967.00
[redacted]		[redacted]	[redacted]	[redacted]

Table C.2: Option 3 – King Street Cost Estimate

	Capital Projects - Project Cost Estimate			
Project	Wallan Reinforcement Options			
Prepared by	Steven Crocker			
Date	26/08/2016			
Revision	A			
Scope of works	2019: R4 - Duplication of supply along King St (between Bentick & William Streets)			

	Description	Total Qty	Unit Rate	Total rate
LabourCost				
Mainslaying	R4: 80m x 63mm PE pipe (	1	60,806.00	60,806.00
	PM Allowance	1	6,100.00	6,100.00
				0.00
				0.00
				0.00
				0.00
				0.00
				0.00
Sub-total				66,906.00
Materials				
Line pipe	63mm PE pipe	80	3.46	276.80
Fitting	Elbows, Tees, & Caps	1	100.00	100.00
Consumables	Warning tape, consumables etc	1	100.00	100.00
				0.00
				0.00
				0.00
Sub-total				476.80
Contingency				0.00
Environmental				
				0.00
				0.00
Sub-total				0.00
Detailed Design				
				0.00
				0.00
				0.00
				0.00
Sub-total				0.00
Direct Cost				67,382.80

Table C.3: Option 3 – Franklin Close Cost Estimate

	Capital Projects - Project Cost Estimate			
Project	Wallan Reinforcement Options			
Prepared by	Steven Crocker			
Date	26/08/2016			
Revision	A			
Scope of works	2019: R4 - Duplication of supply along King St (between Bentick & William Streets)			

	Description	Total Qty	Unit Rate	Total rate
LabourCost				
Mainslaying	R4: 80m x 63mm PE pipe	1	60,806.00	60,806.00
	PM Allowance	1	6,100.00	6,100.00
				0.00
				0.00
				0.00
				0.00
				0.00
				0.00
Sub-total				66,906.00
Materials				
Line pipe	63mm PE pipe	80	3.46	276.80
Fitting	Elbows, Tees, & Caps	1	100.00	100.00
Consumables	Warning tape, consumables etc	1	100.00	100.00
				0.00
				0.00
				0.00
Sub-total				476.80
Contingency				0.00
Environmental				
				0.00
				0.00
Sub-total				0.00
Detailed Design				
				0.00
				0.00
				0.00
				0.00
Sub-total				0.00
Direct Cost				67,382.80

Table C.5: Option 4 – William Street Cost Estimate

	Capital Projects - Project Cost Estimate			
Project	Wallan Reinforcement Options			
Prepared by	Steven Crocker			
Date	26/08/2016			
Revision	A			
Scope of works	2019: R3 Duplication of existing supply main on William St (Northern Hwy to Windham St)			
	Description	**Total Qty**	**Unit Rate**	**Total rate**
LabourCost				
Mainslaying	R3: 290m x 180mm PE Pipe	1	240,119.00	240,119.00
	PM Allowance	1	25,000.00	25,000.00
				0.00
				0.00
				0.00
				0.00
				0.00
				0.00
Sub-total				265,119.00
Materials				
Line pipe	180mm PE pipe	290	27.11	7,861.90
Fitting	Elbows, Tees, & Caps	1	200.00	200.00
Consumables	Warning tape, consumables etc	1	200.00	200.00
				0.00
				0.00
				0.00
Sub-total				8,261.90
Contingency				0.00
Environmental				
				0.00
				0.00
Sub-total				0.00
Detailed Design				
				0.00
				0.00
				0.00
				0.00
Sub-total				0.00
Direct Cost				273,380.90

Table C.6: Option 4 – King Street Cost Estimate

	Capital Projects - Project Cost Estimate			
Project	Wallan Reinforcement Options			
Prepared by	Steven Crocker			
Date	26/08/2016			
Revision	A			
Scope of works	2019: R4 - Duplication of supply along King St (between Bentick & William Streets)			
	Description	**Total Qty**	**Unit Rate**	**Total rate**
LabourCost				
Mainslaying	R4: 80m x 63mm PE pipe	1	60,806.00	60,806.00
	PM Allowance	1	6,100.00	6,100.00
				0.00
				0.00
				0.00
				0.00
				0.00
				0.00
Sub-total				66,906.00
Materials				
Line pipe	63mm PE pipe	80	3.46	276.80
Fitting	Elbows, Tees, & Caps	1	100.00	100.00
Consumables	Warning tape, consumables etc	1	100.00	100.00
				0.00
				0.00
				0.00
Sub-total				476.80
Contingency				0.00
Environmental				
				0.00
				0.00
Sub-total				0.00
Detailed Design				
				0.00
				0.00
				0.00
				0.00
Sub-total				0.00
Direct Cost				67,382.80

Table C.7: Option 4 – Dudley Street Cost Estimate

		Capital Projects - Project Cost Estimate			
Project		Wallan Reinforcement Options			
Prepared by		Steven Crocker			
Date		26/08/2016			
Revision		A			
Scope of works		2021: R5-1 Duplication of existing main in Dudley Street (from Watson St to Adrian Circuit)			

	Item	Description	Total Qty	Unit Rate	Total rate
LabourCost	1				
Mainslaying	1	310m x 125mm PE Pipe	1	217,736.00	217,736.00
		PM Allowance	1	22,000.00	22,000.00
					0.00
					0.00
					0.00
					0.00
					0.00
					0.00
Sub-total					239,736.00
Materials	2				
Line pipe	2.1	125mm PE pipe	310	12.85	3,983.50
Fitting	2.2	Elbows, Tees, & Caps	1	200.00	200.00
Consumables	2.3	Warning tape, consumables etc	1	200.00	200.00
					0.00
					0.00
					0.00
Sub-total					4,383.50
Environmental	4				
					0.00
					0.00
Sub-total					0.00
Detailed Design	5				
					0.00
					0.00
					0.00
					0.00
Sub-total					0.00
Direct Cost	8				244,119.50

Table C.8: Option 4 – Dudley Street Cost Estimate

	Capital Projects - Project Cost Estimate			
Project	Wallan Reinforcement Options			
Prepared by	Steven Crocker			
Date	26/08/2016			
Revision	A			
Scope of works	2021: R5-2 Connect existing P7 main in Adrian Circuit to existing P6 main in Laffy Street			
	Description	**Total Qty**	**Unit Rate**	**Total rate**
LabourCost				
Mainslaying	100m 125mm PE pipe	1	109,065.00	109,065.00
	PM Allowance	1	11,000.00	11,000.00
				0.00
				0.00
				0.00
				0.00
				0.00
				0.00
Sub-total				120,065.00
Materials				
Line pipe	125mm PE pipe	100	12.85	1,285.00
Fitting	Elbows, Tees, & Caps	1	100.00	100.00
Consumables	Warning tape, consumables etc	1	100.00	100.00
				0.00
				0.00
				0.00
Sub-total				1,485.00
Environmental				
				0.00
				0.00
Sub-total				0.00
Detailed Design				
				0.00
				0.00
				0.00
				0.00
Sub-total				0.00
Direct Cost				121,550.00

Table C.9: Option 4 – Duke Street Cost Estimate

	Capital Projects - Project Cost Estimate			
Project	Wallan Reinforcement Options			
Prepared by	Steven Crocker			
Date	26/08/2016			
Revision	A			
Scope of works	Option 3 - 2021: R5-3 Connect existing P7 main in Duke Street to existing P6 main in Wyatt Way			

	Description	**Total Qty**	**Unit Rate**	**Total rate**
LabourCost				
Mainslaying	20m x 125mm PE Pipe	1	38,019.00	38,019.00
	PM Allowance	1	3,800.00	3,800.00
				0.00
				0.00
				0.00
				0.00
				0.00
				0.00
Sub-total				41,819.00
Materials				
Line pipe	125mm PE pipe	20	12.85	257.00
Fitting	Elbows, Tees, & Caps	1	100.00	100.00
Consumables	Warning tape, consumables etc	1	100.00	100.00
				0.00
				0.00
				0.00
Sub-total				457.00
Environmental				
				0.00
				0.00
Sub-total				0.00
Detailed Design				
				0.00
				0.00
				0.00
				0.00
Sub-total				0.00
Direct Cost				42,276.00

Table C.10: Option 4 – Duke Street/Northern Highway Cost Estimate

Capital Projects - Project Cost Estimate

Project	Wallan Reinforcement Options
Prepared by	Steven Crocker
Date	26/08/2016
Revision	A
Scope of works	2021: R6 Connect existing P2 mains in Duke Street on either side of Northern Hwy

	Item	Description	Total Qty	Unit Rate	Total rate
LabourCost	1				
Mainslaying	1	70m x 63mm PE Pipe	1	69,805.00	69,805.00
		PM Allowance	1	7,000.00	7,000.00
					0.00
					0.00
					0.00
					0.00
					0.00
					0.00
Sub-total					76,805.00
Materials	2				
Line pipe	2.1	63mm PE pipe	70	3.46	242.20
Fitting	2.2	Elbows, Tees, & Caps	1	100.00	100.00
Consumables	2.3	Warning tape, consumables etc	1	100.00	100.00
					0.00
					0.00
					0.00
Sub-total					442.20
Environmental	4				
					0.00
					0.00
Sub-total					0.00
Detailed Design	5				
					0.00
					0.00
					0.00
					0.00
Sub-total					0.00
Direct Cost	8				77,247.20
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Other Assets Business Cases

Business Case	Capex Value ($2016)
V01 City Gate Refurbishment – Earthing & Surge Protection 1 Supporting Information 1: G Cope & Assoc Report on Seymour City Gate Surge Event	$0.2m
V02 Cathodic Protection Systems – Replacement & Installation	$1.1m
V05 Plant & Equipment Upgrade	$4.0m
V10 Depot Office Refurbishment 1 Supporting Information 1: Ardent Architect Report 2 Supporting Information 2: Albury Works & Furniture Supplier Quotations	$3.6m
V27 Inspection & Refurbishment – Sleeved Railway Casing Pipes	$0.4m
V34 Replacement of Grove Model 82 Regulators 1 V34 Supporting Information 1: NPV & Options Analysis 2 V34 Supporting Information 2: Parts Quotation	$1.7m
V35 I&C Meter Sets Fisher 298 Replacement 1 Supporting Information 1 : V35 Supporting Information 1 (NPV and Options analysis) 2 Supporting Information 2: Quotation Fisher 298 spares and Fisher EZR Regulators	$0.7m
V37 End of Life Replacement Water Bath Heater Coil	$0.2m
V38 City Gate Refurbishment 1 Supporting Information 1: NPV & Options Analysis	$0.4m
V41 City Gate and Field Regulator Pipework Refurbishment 1 Supporting Information 1: NPV & Options Analysis	$0.3m
V44 Transmission & Network Isolation Valve Replacement	$0.6m
V62 Bushfire Preparedness	$2.9m
V79 I & C Meter Set Refurbishment Program 1 V79 Supporting Information 1: NPV & Options Analysis	$3.8m
V83 Transmission Pipeline Modification for In-Line Inspections 1 V83 Supporting Information 1: NPV & Options Analysis.	$13.6m
V91 Odorant Injection Station	$0.3m
V95 Pressure Regulating Facilities – Isolation Valve	$0.3m

Note: Supporting Information files have been provided separately.

Business Case – Capex V01

City Gate Refurbishment – Earthing and Surge Protection

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	Justin Tanti, *Supervisor Asset Protection*
Approved By	Andrew Foley, *General Manager Victorian Networks*

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	Australian Gas Networks Limited (AGN) has identified 21 city gates that require electrical surge protection to be installed. After taking into account available resources 12 sites will have been completed by the end of 2017. At the start of the next (2018-2022) Access Arrangement (AA) period there will be 9 city gate sites in the AGN Victorian network that require design and installation of electrical surge protection to be compliant with the requirements of AS 4853 Electrical Hazards on metallic pipelines, and AS 1768 - Lightning protection. If this work is not carried out there is a risk that a future lightning strike at a city gate could result in an ignition of gas, fire, explosion, damage to assets and risk public safety and the safety of employees. AGN has already had some experience with this type of risk with the Seymour City Gate having been struck by lightning in 2009. This strike caused ignition of gas and some damage to the infrastructure and equipment. An independent expert report that was prepared shortly after this incident recommended a number of measures to mitigate this risk in the future. Work has commenced on addressing the risk at a number of city gates in the current AA period, with electrical surge protection expected to be installed at 12 of the 21 city gates that have previously been identified as requiring such protection by the end of this AA period, leaving another 9 to be completed in the next AA period. This work program was approved by the AER in the last AA review. In addition to addressing these risks, AGN has identified 50 city gate compounds that need to have their fences earthed in order to meet the upgraded requirements of AS 2885.1.
Options Considered	The following options have been considered: 1 Option 1: Do nothing; or 2 Option 2: Install earthing and lightning surge protection at the remaining 9 sites and earthing to fences at a total of 50 city gate compounds (totaled across the 9 where lightning protection is being added and 41 additional sites being connected to the local common earth system)
Proposed Solution	Option 2 has been selected because it is the most cost-effective solution and reduces the risks to human health and safety to as low as reasonably practicable in a manner that balances cost and risk.

Estimated Cost	The proposed capital expenditure for this project is $188 ($000, 2016).

Consistency with the National Gas Rules (NGR)	The installation of earthing and surge protection at City Gates complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because:
	• 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)); and
	• it is justified under rule 79(2)(c) as it is required to:
	  • maintain and improve the safety of services (79(2)(c)(i)); and
	  • maintain the integrity of services (79(2)(c)(iii));

Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Safety theme as its implementation will allow AGN to improve the safe supply of natural gas to customers by ensuring equipment and fencing is properly earthed in accordance with Australian standards. More information detailing the results of the stakeholder engagement program is provided in Chapter 5 of the Access Arrangement Information document.
Supporting Information	• Supporting Information 1: G Cope & Assoc Report on Seymour City Gate Surge Event

1.3. Background

1.3.1. Problem

There are currently (May 2016) 15 city gate sites in the AGN Victorian network that require design and installation of electrical surge protection to be compliant with the requirements of AS 4853 Electrical Hazards on metallic pipelines, and AS 1768 - Lightning protection, but by the end of this AA period this number is expected to fall to 9 city gate sites (See Appendix C for full list of sites and requirements). The project involves each site being reviewed and the appropriate protection installed.

The facilities in question are shared sites with APA Group, which is responsible for Custody Transfer Metering. AGN has reached agreement with APA Group to standardise common earthing systems to support surge protection and operator safety to the sites on a mutually acceptable basis. AGN expects to connect to APA Group's surge protection earthing system.

The need for the proposed works stems from a lightning strike at the Seymour City Gate in November 2009 which caused ignition of gas and some damage to the infrastructure and equipment. Events such as this have the potential to cause a significant incident such as an explosion.

AGN engaged Geoff Cope and Associates Pty Ltd to assist with reviewing the Seymour incident and to provide guidance as to the possible cause and the remedial works which might be considered to reduce the probability of any recurrence at this or other similar locations. In May 2010 a report was prepared (refer Appendix C). The main recommendation of this report was that all metalwork and pipework in city gates and regulator pits should be electrically bonded via suitable bonding cables or surge protection devices.

The recommended solution discussed in AS 1768 is to employ equipotential bonding of pipelines and metallic structures, either by direct connection or via appropriate surge protection devices where direct connection may cause unwanted effects, such as loss of cathodic protection. No other option has been identified that meets the requirements of AS 1768 and AS 4853.

The current earthing practice at city gate sites constructed since 2011 is for APA Group and AGN structures and equipment to be bonded to the same earthing system. Older AGN and APA Group shared city gate sites have an established earthing system to which APA Group structures and equipment are connected. AGN structures and equipment may or may not be earthed, and if they are, will be by individual earth rods, which has proven to be inadequate. Work needs therefore to be carried out on these assets to install electrical surge protection. If this work is not carried out there is a high risk that a future lightning strike at a city gate could result in an ignition of gas, fire, explosion, damage to assets and risk public safety and safety of employees, which is in turn an Occupation Health and Safety (OH&S) issue.

In addition to these issues, AGN has found that the fences around 50 of the city gate compounds are required to be earthed in order to comply with AS 2885.1 2012, Cl 6.2.4.4, which states that "Station piping and equipment shall be properly earthed to discharge fault or induced voltages safely. The equipment and facilities, including fencing, shall be earthed to protect personnel and equipment from harm or damage in the event of lightning strike." Although it is not a requirement of the Standard for these existing physical assets to be modified retrospectively, it is considered prudent for safety reasons that the compound fences be earthed in order to establish correct equipotential bonding and eliminate any 'touch potential' issues during a high voltage event. The technical solution is to modify 50 city gate sites during the next Access Arrangement Period (AA period) to connect AGN structures and equipment, including the compound fences, to the established common earthing system.

1.3.2. Continuing Project

This project to provide earthing to pipework and structures was previously proposed and approved by AER in the current AA period[1,2] All city gate sites were assessed for earthing and surge protection compliance for pipework and equipment, and 21 were found to need work to ensure compliance. Higher risk city gate sites have been completed first, and to date (April 2016), 6 sites have been completed, and another 6 sites are expected to be completed by the end of the current AA period, resulting in an estimated 12 sites being completed by December 2017 and 9 sites to be completed in the next AA period.

The reasons for completing only 12 sites instead of the 21 that required upgrading include:

- The work at a number of the sites was, for efficiency purposes, combined with other more extensive site upgrade works, and being a part of a larger project, this introduced the need to co-ordinate with the other work scope, resulting in timing constraints and delays.
- Work being delayed due to higher priority works, such as critical corrosion repairs required on transmission pipelines, taking precedence.

In addition, since the initial review was completed, it has been established that the compound fences of 50 city gate sites also require earthing in order to retrospectively comply with AS 2885.1 requirements. This portion of the current business case (V01) was not therefore previously part of the AER's approval.

[1] Business Case V35.
[2] AER – Access Arrangement Final Decision – Envestra Ltd, 2013-17, Part 2 Attachments, Table 4.28, pg. 135.

1.4. Risk Assessment

A risk assessment has been carried out using APA's established evaluation criteria (detailed in Appendix A – Risk Assessment) to produce an estimated level of risk, which is summarised in Table 1.3.

As this table shows, the risk associated with the failure to install earthing and surge protection to City Gate sites, and failure to earth city gate compound fences currently without same as has been assessed as "High".

Table 1.3: Risk Rating

Risk Area	Untreated Risk Level
Health and Safety	High
Environment	Moderate
Operational	High
Customers	Moderate
Reputation	High
Compliance	High
Financial	Moderate
Untreated Risk Rating	**High**

The health and safety risks on sites that do not meet the current industry standard include electric shock and injury to personnel due to inadequate earthing of metallic structures in and around the city gate site. One threat that this work mitigates is that of a lightning strike on a pipeline quite remote from the city gate site travelling along the underground pipe into the above ground pipework at the site, and finding an earth path through operational personnel who are working there. Taking steps to protect against such a threat is standard practice in the pipeline industry, as reflected in the Australian Standards cited above.

Similar operational threats exist, where inadequately earthed equipment such as water bath heaters could sustain damage that renders them inoperable, resulting in loss or reduction of supply, potentially affecting between 10,000 and 30,000 consumers. This poses a reputational, financial and compliance risk, assessed as being "High".

1.5. Options Considered

AGN has identified the following options to address the risks outlined in section 1.4:

- Option 1: Do nothing (i.e. cease installing earthing and lightning surge protection at the end of this AA period).
- Option 2: Install earthing and surge protection equipment at the 9 remaining sites as recommended in the Geoff Cope and Associated Pty Ltd report as a continuation of work approved by the AER in the current AA period, and earthing to fences at 50 sites as required to comply with AS 2885.1.

1.5.1. Option 1 – Do Nothing

This option involves ceasing the current work in the current AA period to rectify earthing and surge protection issues at city gates.

1.5.1.1. Cost/Benefit Analysis

If this option was implemented it would mean that at 50 city gates (41 which require the connection of compound fencing to the existing common earth system, and the other 9 where earthing and surge protection is being installed in addition):

- City gate equipment is at risk of failure during a lightning strike, with the consequent risk that gas supply may be interrupted to downstream customers, as well as risk to human health and safety and equipment damage. Typically between 10,000 and 30,000 customers may lose supply or be subject to reduced supply.
- Costs to repair equipment after lightning strikes at those unprotected sites would be incurred that are far greater than the cost of the earthing itself. A recent lightning strike provides an example. The cost of repairs to the Seymour City Gate after the lightning strike incident was not accounted for separately, as the work was combined with a larger site upgrade. However, it is estimated that the repair cost of the regulator pit and equipment at a city gate could be up to $300 ($000, 2016), depending on the extent of the damage.

The residual risk under this option would therefore remain High (see Appendix A).

The only benefit of this option is that capital expenditure would cease.

1.5.2. Option 2 – Continue to install earthing and surge protection equipment

Under this option, the program of installing earthing and surge protection to sites not completed in the current AA period would be continued. Nine sites are planned for the next AA period, at an average of 2 per year, and this would complete the original program outlined in the Geoff Cope and Associates report.

The average of 2 per year is consistent with the average number completed each year in the current AA period (12 completed over 5 years = 2.4 per year)

This option also includes the connection of compound fences to the common earth system within the city gate at 50 sites, consisting of the 9 where earthing of equipment and surge protection is being undertaken, and an additional 41 sites.

1.5.2.1. Cost/Benefit Analysis

If this option is implemented, all the city gates would be upgraded to meet the current technical standards and OH&S legislation, and:

- AGN personnel would be protected from hazardous conditions during a lightning strike;
- the risk to supply is mitigated due to fit for purpose lightning protection installed at City Gates; and
- the costs to repair equipment after lightning strikes would be minimised.

The residual risk under this option would therefore fall from High to Moderate (see Appendix A).

This option is estimated to cost $188.2 ($000, 2016) over the term of the next AA period, for 2 sites per annum for earthing of the pipework and equipment, and 10 sites per annum for earthing of fences. Further detail on this estimate is provided in section 1.7.3.

1.6. Summary of Cost/Benefit Analysis

Table 1.4 gives a summary of the costs and benefits associated with each option.

Table 1.4: Summary of Costs and Benefits

Option	Benefits	Costs/Risks
Option 1	No capex is required	Potential high costs to repair equipment damaged by lightning. Potential loss of or restriction in supply to between 10,000 and 30,000 customers (depending on which city gate is affected). Health and safety related risks remain High.
Option 2	AGN is compliant with OH&S legislation, and Australian standards. Risk of injury to personnel from lightning strikes is minimised. Potential high costs to repair equipment damaged by lightning are avoided or minimised. Potential loss of or restriction in supply to large numbers of customers is minimised. Risks reduced from High to Moderate.	$188.2 ($000, 2016) for 50 sites over the 5 years of the next AA period.

1.7. Proposed Solution

1.7.1. What is the Proposed Solution?

Option 2 has been selected, which will involve installing earthing and surge protection at nine sites and connecting compound fences to the common earth system within the city gate at 50 sites.

1.7.2. Why are we Proposing this Solution?

Option 2 is being proposed because it is the most cost-effective solution and reduces the risks to human health and safety and operational risks to as low as reasonably practicable in a manner that balances cost and risk. The other benefits of this option are that it will:

- Increase safety by mitigating the risk of hazards to operational personnel due to lightning strike.
- Reduce the risk of loss of or reduced supply to consumers due to damage from lightning strikes.
- Ensure compliance with Australian standards regarding protection of plant and facilities during hazardous events.

- Mitigate the risk of damage sustained by lightning strikes such as occurred at the Seymour city gate.

This option will also reduce the assessed risks from High to Moderate.

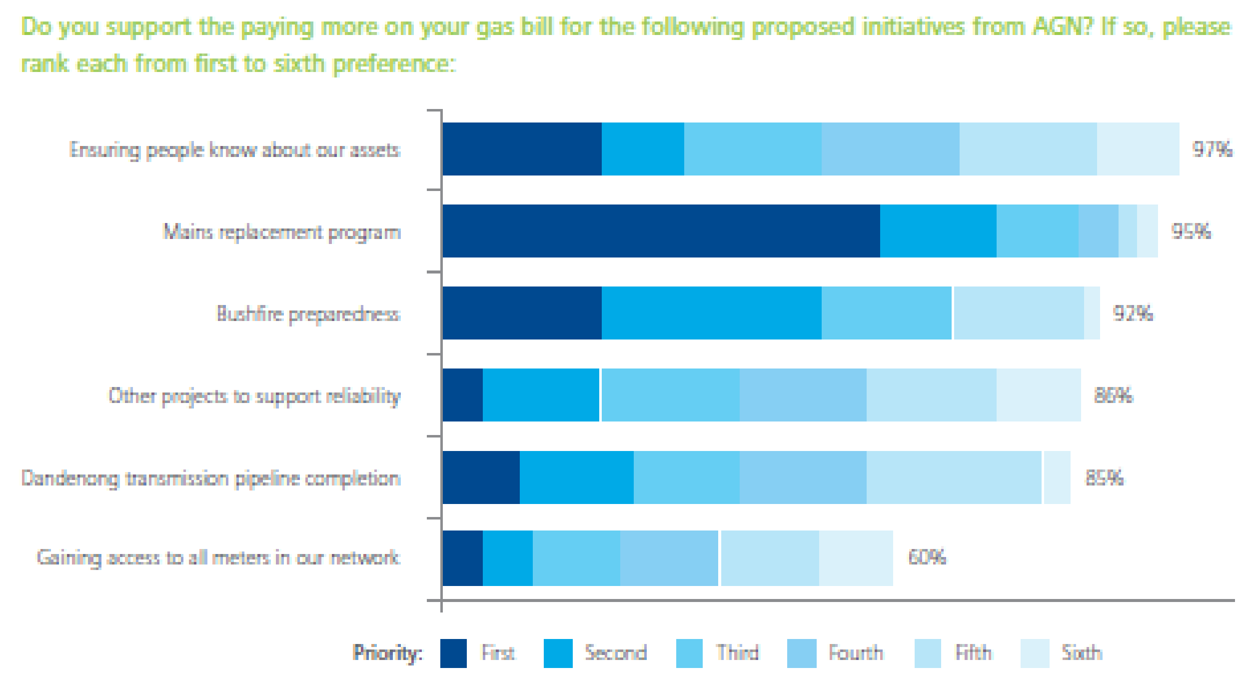
Finally, it is worth noting that this project is consistent with the findings from the stakeholder engagement program, which are outlined below.

1.7.3. Stakeholder Engagement

Overall, our customers told us that they value current standards of reliability and are supportive of initiatives that maintain their reliability and improve the safety of the network with the majority of participants prepared to pay to support the maintenance of the existing level of reliability of the network.

As demonstrated in Figure 1 below, projects that support reliability received support from 86% of workshop participants, behind only awareness of AGN assets, ongoing mains replacement program and bushfire preparedness when ranked in order of importance.

Figure 1.1: Workshop Support of AGN’s Proposed Initiatives, Broken Down by Preference



1.7.4. Forecast Cost Breakdown

The costs of the project can be divided into two components:

- continuing the work to install earthing and surge protection to equipment and above ground pipework within the city gates, and
- connection of city gate compound fences to the common earthing grids.

The estimate has been developed based on:

- For the pipework and equipment earthing, the historical average cost (of a contractor) of performing the work over the last 3 years (i.e. in the current AA period).

- For connection of fences to the common earth grid, the assumption that the required scope is similar to the scope for earthing and surge protection of equipment and piping (ie takes the same amount of time on any one site), and this the cost (all contractor cost) will therefore be the same as the contractor cost for the equipment earthing.
- The requirement for one APA (AGN's operator) technician to attend site for 2 days for the equipment and piping component, at an hourly rate of [redacted] / hr.
- Accommodation costs for the APA technician at half of the 9 sites where the equipment and piping component is required.

Table 1.5 shows a summary of the costs over the next AA period.

1.7.4.1. Earthing and Surge Protection to Equipment and Pipework

The estimated cost of this component is [redacted] ($000, 2016) for 9 sites over the next AA period, which is based on the average of actual costs incurred for similar work at 5 of the 6 city gates completed to date (May 2016), and an estimated 16 hours per site for internal labour of an Electrical & Instrumentation technician at current labour rates.

The average cost per site is $37 ($000, 2016), and the derivation of this average, and the detailed cost estimate are shown in Appendix B.

1.7.4.2. Earthing of fences

The estimated cost of this component is [redacted] ($000, 2016) for 50 city gate sites over the next AA period. As the scope of the work is similar to that of earthing equipment and pipework, the per site cost estimate for this component is based on the average contractor costs for earthing and surge protection above in Section 1.7.3.1

The average cost per site is [redacted] ($000, 2016), and the derivation of this average, and the detailed cost estimate are shown in Appendix B.

Table 1.5: Project Cost Estimate ($000, 2016)

	2018	2019	2020	2021	2022	Total
Equipment Earthing and Surge Protection						
Number of sites	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average cost / site	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Sub-total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fences Earthing						
Number of sites	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average cost / site	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Sub-total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

* Numbers may not add due to rounding

1.7.5. Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN considers the forecast capex for this project to be:

- *Prudent* – The expenditure is necessary to ensure that the ongoing integrity of the city gates is maintained and there are no major gas escapes that could impact public safety and reliability of supply. The expenditure minimises potential hazards during lightning strikes at these locations. The expenditure is also of a nature that a prudent service provider would incur given the risks and prior experience in Seymour.
- *Efficient* – The estimated costs of this project are considered efficient because they are based on the average of historical actual costs over the last 3 years, with both historic contractor and material costs procured through competitive processes.
- *Consistent with accepted good industry practice* – The identification and rectification of potential hazardous issues as outlined above and the reduction of risk to as low as reasonably practicable in a manner that ensures compliance with Australian Standards is in keeping with accepted and good industry practice. So too is ensuring maintenance of earthing systems is consistent with current accepted technical solutions.
- *Achieves the lowest sustainable cost of delivering pipeline services* – The forecast expenditure is the most effective long term option, as it minimises reactive repair costs associated with lightning strikes, and avoids potential costs of loss of supply to by needing to restore supply (re-light) to large numbers of customers, with potential consequent legal and/or compensation costs.

The capex can therefore be viewed as being consistent with rule 79(1)(a) of the NGR. The proposed capex is also consistent with rule 79(1)(b), because the expenditure is necessary to:

- *maintain and improve the safety of services (rule 79(2)(c)(i))* - electrical earthing significantly mitigates against potential injury or death of personnel who would otherwise be exposed, and also protects the asset against electrical damage or explosion; and
- *maintain the integrity of services (rule 79(2)(c)(ii))* - by ensuring that the asset is protected against a now foreseeable threat which has been highlighted by recent experience, and has the potential if not addressed to result in an interruption to supply arising from lightning strike damage.

Appendix A – Risk Assessment

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Option Risk
Risk Untreated	**Likelihood**	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*High*
	Consequence	*Significant*	*Medium*	*Major*	*Medium*	*Significant*	*Significant*	*Medium*	
	Risk Level	*High*	*Moderate*	*High*	*Moderate*	*High*	*High*	*Moderate*	
Residual Risk Option 1	**Likelihood**	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*High*
	Consequence	*Significant*	*Medium*	*Major*	*Medium*	*Significant*	*Medium*	*Medium*	
	Risk Level	*High*	*Moderate*	*High*	*Moderate*	*High*	*Moderate*	*Moderate*	
Residual Risk Option 2	**Likelihood**	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Moderate*
	Consequence	*Significant*	*Medium*	*Major*	*Medium*	*Significant*	*Medium*	*Medium*	
	Risk Level	*Moderate*	*Low*	*Moderate*	*Low*	*Moderate*	*Low*	*Low*	

Appendix B – Detailed Cost Estimate

DESCRIPTION	Units	UOM	$/unit	ITEM COST	TOTAL COST
NUMBER OF SITES					
Equipment & Pipework	[redacted]	[redacted]			
Fencing	[redacted]	[redacted]			
TOTAL SITES	[redacted]	[redacted]			
MATERIALS					
Included in Contractor costs					
					[redacted]
LABOUR					
Equipment & Pipework Earthing & Surge Protection (9 Sites)					
Contractor					
David Suttie Pty Ltd - average site cost based on average of actual costs of 5 typical sites	[redacted]	[redacted]	[redacted]	[redacted]	
E&I Technician labour (Internal)					
2 days x 8 hr each day for 1 internal resource, 9 sites	[redacted]	[redacted]	[redacted]	[redacted]	
Accommodation					
2 nights ea x 9 sites for E&I Tech	[redacted]	[redacted]	[redacted]	[redacted]	
Total costs for Equipment earthing and surge protection					[redacted]
Average per site					[redacted]
Earthing of Fences					
David Suttie Pty Ltd - average site cost is similar cost to equipment earthing	[redacted]	[redacted]	[redacted]	[redacted]	
Total costs for Earthing of Fences					[redacted]
Average per site					[redacted]
TOTAL ESTIMATED COST - 59 Sites - over 5 years					**$188,257**

Appendix C – Location Details

City Gate Earthing List 2014

Heater/Kiosk Earthed	Location	Water Bath Heater earth	Kiosk earth	Fencing
Yes	Bairnsdale City Gate			
	Benalla City Gate	no earth		
	Benalla City Gate (Monsbent)		no earth	
	Berwick City Gate			
Yes	Beveridge City Gate			
Yes	Broadford City Gate			
Yes	Chiltern City Gate			
Yes	Churchill			
Yes	Cloverlea (Darnum) field reg			
Yes	Clyde North Tuckers Rd			
Yes	Cobram City Gate			
Yes	Cranbourne (west) Huon Park Rd			
Yes	Cranbourne (east) Narre Warren Rd			
Yes	Dandenong Terminal Station			
Yes	Docklands metering station			
Yes	Drouin South			
	Echuca City Gate	no earth		
	Epping	no earth		
	Euroa City Gate		no earth	
	Hampton Park City Gate	no earth		
Yes	Healesville City Gate			
Yes	Keon Park metering pits			
Yes	Kilmore city gate			
Yes	Koonoomoo City Gate			
	Kyabram City gate	no earth	no earth	
Yes	Longwarry City Gate			
Yes	Lyndhurst			
Yes	Melbourne Queens Wharf Rd			
	Mernda (Laurimer Park) City Gate	no earth		
	Merrigum City Gate	no earth	no earth	
Yes	Moe			
Yes	Morwell Reg Station			
Yes	Morwell City Gate Firmins Lane			
Yes	Morwell Pig Trap Station			
Yes	Narre Warren City Gate			
Yes	North Melbourne Langford St			
Yes	Officer Metering Station			
Yes	Pakenham Koo Wee Rup Rd			
Yes	Pakenham Dore Rd BassGas			
Yes	Rosedale City Gate			
	Rutherglen City Gate		no earth	
Yes	Sale City Gate			
Yes	Seymour City Gate Puckapunyal			
Yes	Seymour City Gate Telegraph Rd			
Yes	Shepparton City Gate			
	Tatura City Gate	no earth	no earth	
Yes	Templestowe Fitzsimons La			
	Tongala City Gate	no earth		
Yes	Trafalgar Contingent St			
Yes	Traralgon City Gate			
Yes	Wallan City Gate			
	Wangaratta City Gate	no earth		
Yes	Wangaratta East City Gate			
Yes	Warragul Anderson St			
Yes	Whittlesea City Gate			
Yes	Wodonga City Gate			
Yes	Yarragon Loch St south			
Yes	Yarrawonga City Gate			
Yes	Bombala City Gate			
Yes	Boman City Gate			
Yes	Cooma City Gate			
Yes	Culcairn City Gate			
Yes	Gundagai City Gate			
Yes	Henty City Gate			
Yes	Illabo City Gate			
Yes	Tumut City Gate			
Yes	Uranquinty City Gate			
Yes	Wallendbeen City Gate			
Note:	All City Gate stations require review for fence earthing requirements.			
	Upgraded during 2011-2015			
	Upgrade planned for 2016-2017			

Business Case – Capex V02

Cathodic Protection Systems – Replacement & Installation

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	Justin Tanti, *Supervisor Asset Protection*
Approved By	Andrew Foley, *General Manager Victorian Networks*

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	Cathodic Protection (CP) is a technique used to control corrosion of metallic objects by making the object the cathode and a sacrificial metal the anode to create an electrochemical cell. AGN's transmission and distribution networks are protected from corrosion by a CP system which consists of a mixture of Galvanic Anodes and an Impressed Current Cathodic Protection (ICCP) system. The ICCP system consists of a bed of anodes connected to a transformer rectifier (known as a CP Unit) which is used to deliver electrical current to the pipeline steel and inhibit corrosion of the asset. An improperly operated or maintained CP system will result in protection against corrosion of the pipe decreasing over time resulting in degradation of the pipeline, and if left untreated will result in gas leaks with subsequent hazards and risks of ignition, fire and risks to public health and safety. The Australian standards which govern the technical requirements for gas pipelines (AS 2885.1-2012 Pipelines-Gas and liquid petroleum-Part 1 Design and construction, AS 2885.3-2012 Pipelines-Gas and liquid petroleum-Part 3 Operation and maintenance, AS 4645.1-2008 Gas distribution networks Part 1 Network management and AS 4645.2-2008 Gas distribution networks Part 2 Steel pipe systems), mandate that CP systems that meet the requirements of AS 2832.1 (Cathodic Protection of Metals Part 1: Pipes and Cables) are installed to assist corrosion protection of buried steel pipelines and distribution systems. The Pipelines Act 2005 and Gas Distribution Code require compliance with AS 2885 and AS 4645 respectively. Through its annual CP system maintenance program and in conjunction with monthly operation and visual checks, Australian Gas Networks Limited (AGN) has identified a number of locations in the Victorian networks where: • The condition of existing CP units and/or Anode beds have deteriorated and require replacement. In total, AGN has identified nine CP units and six anode beds that were installed between 1965 and 1988 that will require replacement in the next five to ten years; and • The installation of smaller anode bed and CP unit combinations in the network is required to address localised CP issues. Historically, AGN has installed approximately four smaller anode bed/CP unit combinations per annum to address these localised issues. To address these issues, work will need to be carried out to: 1 Replace CP units. 2 Replace anode beds. 3 Install additional CP unit / anode bed combinations.

	A combination of the three areas is required to enable the cathodic protection system to be maintained in its most efficient and optimal form, reducing the effects of corrosion, and maintaining the safety of the transmission and distribution pipeline networks. No CP systems in AGN's Albury network were assessed as requiring replacement.

Options Considered	The following options have been identified to address the risks outlined above:
	• Option 1: Do nothing.
	• Option 2: Carry out the following works over the next Access Arrangement (AA) period:
	  ◦ Replace nine CP Units at two per year for four years and then one in the fifth year.
	  ◦ Replace six Anode beds at one per year over four years and then two in the fifth year.
	  ◦ Install 20 new small anode beds at four per year over 5 years.
	• Option 3: Carry out the following works over the next two AA periods (2018-2027):
	  ◦ Replace nine CP Units at one per year over nine years.
	  ◦ Replace six Anode beds at one per year over four years and then two in the fifth year.
	  ◦ Install 20 new small anode beds at four per year over five years.
	
	The only difference between options 2 and 3 is that under Option 2, the nine CP units would be replaced in the next AA period, while under Option 3 they would be replaced over the next nine years.

Proposed Solution	Option 2 has been selected because it is the most cost effective way to reduce the risk posed by poor cathodic protection to as low as reasonably practicable and achieves a reasonable balance between residual risk and cost, consistent with Australian Standards AS 2885.1-2012 Pipelines-Gas and liquid petroleum-Part 1 Design and construction, AS 2885.3-2012 Pipelines-Gas and liquid petroleum-Part 3 Operation and maintenance, AS 4645.1-2008 Gas distribution networks Part 1 Network management and AS 4645.2-2008 Gas distribution networks Part 2 Steel pipe systems.
Estimated Cost	Option 2 is estimated to cost $1,123 ($000, $2016) in capital expenditure (capex) over the next AA period.

Consistency with the National Gas Rules (NGR)	The cathodic protection system replacement and installation project complies with the new capex criteria in rule 79 of the National Gas Rules because:
	• 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)); and
	• it is justified under 79(2)(c) as it is required to:
	  ◦ Maintain and improve the safety of services (79(2)(c)(i));
	  ◦ Maintain the integrity of services (79(2)(c)(ii)); and
	  ◦ Comply with a regulatory obligation or requirement (79(2)(c)(iii))[1].

Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program is drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Reliability and Safety themes as its implementation will allow AGN to maintain the safety of our network, whilst continuing to provide a highly reliable supply of natural gas to our customers by ensuring components of the cathodic protection system are replaced as they reach the end of their useful lives, safeguarding the correct functioning of the whole system. More information detailing the results of AGN's stakeholder engagement program is provided in Chapter 5 of the Access Arrangement Information document.

[1] AS 2832.1, Cathodic Protection of Metals – Pipes and Cables, Section 2.2.2.2

1.3. Background

1.3.1. The role of Cathodic Protection Systems

Cathodic Protection (CP) is a technique used to control corrosion of metallic objects by installing an electrochemical cell which causes sacrificial anodes to corrode instead of the pipe requiring protection. AGN's transmission and distribution networks are protected from corrosion by a CP system which consists of a mixture of Galvanic Anodes and Impressed Current Cathodic Protection (ICCP) systems. An ICCP system consists of a bed of anodes connected to a transformer rectifier (known as a CP Unit) which is used to deliver electrical current to inhibit corrosion of the asset. The Anode beds are sacrificial assets that protect the buried steel pipeline from corrosion (i.e. the anode beds corrode instead of the buried steel pipelines). There are currently 79 CP units in AGN's network and ten anode beds.

Figure 1.1: A Typical CP Unit

Figure 1.2: Installation of an Anode Bed

Should either of the CP unit or anode bed components fail, the networks would be subject to protection levels below the required minimum for an extended period of time until a replacement CP Unit of anode bed can be installed.

This would result in an increased corrosion risk and a gradual degradation of pipe integrity, and so it is prudent to replace the CP units and anode beds when they are at the end of their useful life rather than wait for them to fail. The resulting increase of corrosion on the aging assets will result in an increase of corrosion related incidents and would be detrimental to the longevity of the gas distribution and transmission systems and/or risks to human health and safety through increased gas leaks.

1.3.2. AGN's requirement for Cathodic Protection Systems

Both AS 2885 (Parts 1 and 3) for pipelines operating above 1050 kPa, and AS 4645 for pipelines or distribution networks operating at or below 1050 kPa, have a mandatory requirement that steel pipelines or distribution systems must have CP systems designed and installed to assist in mitigating corrosion[2].

In both standards, it is a mandatory requirement that the design and operation of the CP system shall be in accordance with AS 2832.1 (AS 2832.1 specifies the requirements for CP of buried steel pipes and cables, including design, installation, operation and maintenance).

Both the Pipelines Act 2005 and the Gas Distribution Code require compliance with AS 2885 and AS 4645, and so having properly designed, maintained and functioning CP systems in place to protect the steel pipeline and distribution networks is essentially a mandatory regulatory requirement.

1.3.3. Condition of Cathodic Protection Systems

Through its annual CP maintenance program and in conjunction with monthly operational and visual condition checks, AGN has identified a number of locations in the Victorian networks where CP system assets need to be replaced or new assets installed. These are summarised in Table 2 below.

Table 1.3: Summary of Project Work Streams

Work Stream	Driver
Replacement of CP Units	AGN has carried out an assessment of the condition of the existing CP units and found that nine will need to be replaced in the next five to ten years because they exhibit the following issues: • A number of the CPU units show signs of external corrosion, which if left for extended periods will result in exposure of the internal componentry to the elements which will expedite the chance of failure. • The wire terminals on the DC transformers on a number of CPU units are cracked, exposed and brittle, limiting the ability to make adjustments to output levels. • A number of CP units do not have Residual Current Devices (RCD) for personal protection installed due to their age. • A number of control units require replacement due to insect damage. AGN has also found that the spare parts and components required to repair or maintain these units are either not readily available or are costly to source.
Replacement of anode beds within CP Units	AGN has carried out an assessment of the condition of the existing anode beds within CP units and found that six of the large (10amp) anode beds will need to be replaced in the next five to ten years because the voltage level required to maintain output of these units has been increasing over time, which is an indication that they are deteriorating (see Appendix D).
Installation of new CP Units	Through regular surveys of the level of CP present throughout the network, AGN has found a number of localised areas of the steel network that have poor CP performance and pose a risk to the

[2] AS 2885.1, 2012, Cl 8.3.3 and AS 4645.2 2008, Cl 3.5.2.

	network (i.e. because of the risk of corrosion developing). To address these localised CP issues, AGN has in the past installed smaller (2amp) anode beds, with approximately four of these units installed each year.

Work is required across each of these work streams to enable the ongoing effective operation of AGN's CP systems and to ensure compliance with the cathodic protection requirements of AS 2885 and AS4645. An effective CP system minimises the effects of corrosion and enables assets to meet their useful life, thereby maintaining the safety of AGN's networks.

1.3.4. Continuing Program of Works

This work is a continuation of a program of work that was approved by the AER in the existing AA period under V96 Field Assets Alterations and Replacements. In approving the expenditure, the AER noted the following:[3]

> *"The AER considers that the following projects are justifiable under r. 79(2) of the NGR and would be incurred by a prudent and efficient distribution business acting in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services in accordance with r. 79(1)(a) of the NGR. The AER also considers these forecasts have been arrived at on a reasonable basis."*

Business Case V96 was a high level business case canvassing a broad, but unspecified, range of work within the distribution system that is necessary to ensure assets operate reliably, and asset integrity and continuity of supply to customers is maintained.

The AER approved $7,194 ($000, 2016) over the term of the current AA period, based on actual historical expenditure for this type or work.

AGN will deliver most of this approved program of work over the current AA period, however some of the approved project is included in this business case for delivery over the next AA period due to the diversion of labour resources to other operational priorities. Appendix C shows the list of remaining sites where CP Units and Anode Beds need to be replaced.

1.4. Risk Assessment

The untreated risks associated with CP in the Victorian and Albury networks are summarised in the table below, while Appendix A contains more detail. As this table shows, the untreated risk rating is High.

Table 1.4: Risk Rating

Risk Area	Untreated Risk Level
Health and Safety	High
Environment	Moderate
Operational	High
Customers	High
Reputation	Moderate
Compliance	High
Financial	Moderate
Untreated Risk Rating	**High**

[3] AER, Draft Decision: Access arrangement draft decision Envestra Ltd 2013-17, Part 4, September 2012, *Table A.31.*

Effective pipe coating and a well maintained CP system are the two primary defense mechanisms against corrosion of underground steel pipes. Failure from improper maintenance or poor performance of CP system components will inevitably result in corrosion and subsequent gas leaks as the coating system deteriorates with age. Should a gas leak occur, sections of the network may need to be shut down while repairs are conducted. Should this occur on a transmission pressure pipe, which feeds high, medium and low pressure networks, up to 100,000[4] consumers could be affected.

The risks in this scenario include:

- Health and safety risks to the public before the leak is controlled, with potential ignition and fire and/or explosion.
- Risk of loss of supply to an area while the leak is repaired, resulting in customer complaints, relighting costs and possible compensation payments under the Guaranteed Service Level provisions of the Gas Distribution Code.
- Potential investigation by the ESV for failure to comply with mandatory requirements of Australian standards, and consequently the requirements of the Pipelines Act 2005.

1.5. Options Considered

AGN has identified the following options to address the risks outlined in Section 1.4 and maintain the integrity and effectiveness of the CP systems:

- Option 1: Do nothing.
- Option 2: Carry out the following works over the next AA period:
  - Replace nine CP Units at two per year for four years and then one in the fifth year.
  - Replace six Anode beds at one per year over four years, and then two in the fifth year.
  - Install 20 new small anode beds at four per year over five years.
- Option 3: Carry out the following works over the next two AA periods (2018-2027):
  - Replace nine CP Units at one per year over nine years.
  - Replace six Anode beds at one per year over four years, and then two in the 5th year.
  - Install 20 new small anode beds at four per year over five years.

The only difference between Options 2 and 3 is that under Option 2, the nine CP units would be replaced in the next AA period, while under Option 3 they would be replaced over the next nine years.

1.5.1. Option 1 – Do Nothing

The first option that AGN has identified is to do nothing. Under this option, the normal maintenance program on the CP system will continue, but the current program of capex to replace CP units and major anode beds ceases. Small anode beds which ensure the protection of localised areas of poor CP performance would also not be installed. This will expose the entire CP system to a gradual degradation in effectiveness, and accelerate the establishment of a generalised corrosion threat to the whole network.

[4] In a worst case scenario, if part of the Dandenong to Crib Point TP main had to be shut down for leak repairs, 100,000 customers could potentially be affected.

1.5.1.1. Cost/Benefit Analysis

The only benefit of this option is that there is no upfront capex. However, this will be offset to some extent by an increase in the level of Opex required to address corrosion issues as the assets gradually degrade.

That is, while normal maintenance work, which consists of monthly checks on CP Units to monitor functionality, and any minor repairs undertaken, will continue at similar levels to what currently exists as the CP levels gradually become ineffective, pipelines over time will be subject to increased corrosion, which will affect the integrity of the steel pipeline network and resulting increased dig-up and repair costs as corrosion defects worsen over time.

The other risk posed by this option is that accelerated corrosion may not be discovered before loss of containment occurs. If left unrepaired, it may result in gas leakage and potential fire and/or explosion, which will expose AGN to other financial and reputational consequences.

This option would also result in, over time, AGN not complying with Australian Standards (AS 2885, AS 4645) and the Victorian Gas Distribution System Code to maintain the integrity of its assets.

1.5.2. Option 2 – Replacement in a 5 Year Timeframe

The second option AGN has identified is to:

- replace nine CP Units at two per year for four years, plus one in the fifth year.
- replace six anode beds at one per year over four years; and then two in the 5th year.
- install 20 new small CP units / anode beds at four per year over five years.

1.5.2.1. Cost/Benefit Analysis

This option is estimated to cost $1,123 ($000, 2016) to implement over the next AA period. This estimate is based on the costs of similar projects undertaken in this AA period, supplier quotes and internal APA labour rates.

The benefit of this option is that it will enable the cathodic protection system to be maintained in its most efficient and optimal form, thus reducing the effects of corrosion and maintaining the safety of the transmission and distribution pipeline networks.

Replacing CP Units over five years will minimise the risk of increased corrosion due to the required output current from these units not meeting its performance parameters. The result of this would be reduced protection levels in the pipeline network, and accelerated corrosion resulting in more leaks sooner.

Anode beds are also an integral part of a CP system design, and the effective performance of the system relies on the CP Units and anode beds working in concert as a holistic electrical circuit. Replacement over five years will enable adequate protection levels to be maintained. Extending replacement timeframes will expose the network to, again, increased risk of accelerated corrosion.

The residual risk associated with this option is Low (see Appendix A for more detail).

1.5.3. Option 3 – Replacement of CP Units over two AA periods

The third option AGN has identified is to replace the CP Units over a 9 year timeframe rather than a five year period. Under this option, AGN would:

- Replace nine CP Units at one per year for nine years.
- Replace six anode beds at one per year over four years, and then two in the fifth year.
- Install 20 new small CP units / anode beds at four per year over five years.

1.5.3.1. Cost/Benefit Analysis

This option is forecast to cost the same amount as Option 2 (i.e. $1,123 ($000, 2016), but $116 ($000, 2016) would be deferred to the following (2023-2027) AA period.

The main benefit of this option over Option 2 is that the cost of CP Unit replacement is spread over nine years instead of five, which means that in present value terms the cost is approximately $40 ($000, 2016) lower (assuming a real pre-tax discount rate of 3.98%).

While the cost is marginally lower in present value terms, extending replacement timeframes will expose the network to increased risk of accelerated corrosion, resulting in more leaks sooner. This is because there is an increased risk under this option that larger areas of the network will not be adequately protected due to a longer period of time that the aged and ineffective CP Units are left in place.

In a system where many of the older pipelines are experiencing increased levels of coating degradation, there is a larger reliance on a well maintained CP system to combat corrosion. Ensuring CP Units, which provide the driving current for the system, are fit for purpose is key to achieving this.

The residual risk associated with this option is Moderate (see Appendix A for more detail).

1.6. Summary of Cost/Benefit Analysis

The table below provides a summary of the costs and benefits associated with the three options outlined above.

Table 1.5: Summary of Cost/Benefit Analysis

Option	Benefits	Costs/Risks
Option 1	No upfront capital expenditure.	• Opex increasing over time • Increased risk of loss of containment and gas leakage. • Non-compliance with standards and the Code. • Residual risk High.
Option 2	• Minimise risk of loss of containment due to corrosion • Ensure compliance with Australian Standards and the Code • Opex maintained at current levels. • Residual risk reduced from High to Low.	$1,123 ($000, $2016) over five years
Option 3	For the assets that are replaced in the next AA period, this option will: • Minimise risk of loss of containment due to corrosion • Ensure compliance with Australian Standards and the Code • Opex maintained at current levels. • Residual risk reduced from High to Moderate.	$1,123 ($000, 2016) over 10 years, with $1,007 ($000, $2016) to be spent in the next AA period, and $116 ($000, $2016) in the subsequent AA period. For the CP units that are not replaced in the next AA period, this option will: • Increase the risk of CP unit failure. • Result in higher opex for these CP units. • Increase the risk of loss of containment and gas leakage on these CP units. • Result in non-compliance with standards and

the Code for these CP units.

1.7. Proposed Solution

1.7.1. What is the Proposed Solution?

The proposed solution is Option 2, which will involve:

- Replacing nine CP Units at two per year for four years, and one in the last year of the AA period;
- Replacing six Anode beds at one per year over four years; and then two in the fifth year, and
- Installing 20 new small CP units / anode beds at four per year over five years.

The first two items above address the replacement of aging assets that are at the end of their useful lives and the third provides for continuing to ensure adequate CP system performance at localised areas where local factors contribute to poor performance of the main system.

1.7.2. Why are we Proposing this Solution?

Option 2 is being proposed because it is the most cost effective and prudent solution to ensuring the integrity of steel pipes is maintained by ensuring adequate CP levels. It also achieves a reasonable balance between residual risk and cost, consistent with Australian Standard AS4645 and AS 2885. This option is being proposed over Option 3 because while the cost of Option 3 is lower in present value terms, it will expose the network to a greater degree of risk because four of the CP units won't be replaced until the subsequent AA period. The risks posed to the network by these old CP units is considered to be too high, which is why Option 2 is the selected solution.

It is worth noting in this context that the work proposed for Option 2 is a continuation of the work approved under business case V96 for the current AA period. AGN has performed the work on the CP system as part of the general field asset alteration and replacement category approved under V96, to ensure that AGN has network assets that operate reliably and ensure the integrity of supply to its customers.

AGN has undertaken a comprehensive engagement program to better understand the values of our stakeholders. During this engagement, stakeholders told us that they valued initiatives that improve the safety of our network. Consistent with the above insight, ensuring the correct functioning of the CP network assists in minimising corrosion of AGN's pipeline network and contributes to the provision of a safe supply of natural gas.

1.7.3. Forecast Cost Breakdown

The forecast cost of the project is set out in Table 1.7 below. The detailed cost estimates are provided in Appendix B, and are based on:

- Historical costs for similar projects in the current AA period;
- Internal labour rate for an Electrical/Instrumentation technician (including vehicle) of [redacted] / hr; and
- Quotations from suppliers – for example, anodes for installation in a large anode bed being replaced from Anode Engineering in Brisbane (see Appendix B).

Table 1.6: Project Cost Estimate, by Category ($000, 2016)

	2018	2019	2020	2021	2022	Total
CP Unit Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Major Anode Bed Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
New localised CPU / anode bed combinations	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Note: Totals may not add due to rounding.

1.7.4. Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN considers the forecast capex for this project to be:

- *Prudent* – It is incumbent on gas distribution network owners to ensure that equipment continues to function and is replaced when it is no longer fit for purpose (i.e. due to age, breakdown or other reason). Having identified that these assets require replacement, AGN has adopted a prudent approach of replacing the relatively small volumes over a five year period. To extend this to ten years would expose the network to increased corrosion levels, resulting in an increased risk of additional expenditure to repair identified corrosion, and/or unidentified corrosion resulting in loss of containment or fire and resulting damage. In this context, it is prudent to institute preventative measures rather than reactive repairs.
- *Efficient* – The proposed expenditure is considered efficient because it is based on the actual costs of contractors and suppliers for similar work (see Appendix B). These contractors and suppliers were selected through a competitive tender process with material and labour pricing fixed for the term of a supply contract. These prices are also tested against market quotes for identical or similar material and labour as standard practice.
- *Consistent with accepted good industry practice* – CP of steel pipeline systems is a long established method of preventing corrosion. Along with the physical pipeline coating it represents the prime prevention measure against corrosion. Ensuring correct functioning of the system in accordance with its design by replacing aged and non-functioning equipment is a normal asset management function, and is required to comply with AS 2832.1. Reducing the risks posed by the lack of CP to as low as reasonably practicable is also consistent with Australian Standards AS2885 and AS4645.
- *To achieve the lowest sustainable cost of delivering pipeline services* – Delivering the project in the next AA period is the most cost-effective way to reduce the risk posed by poor CP to as low as reasonably practicable and achieves a reasonable balance between residual risk and cost, consistent with Australian Standards AS2885 and AS4645.

The capex can therefore be viewed as being consistent with Rule 79(1)(a) of the NGR.

The proposed capex is also consistent with rule 79(1)(b), because the expenditure is necessary to:

- *Maintain and improve the safety of services (rule 79(2)(c)(i))* - by ensuring gas leaks are minimised with the operation of an adequate CP system.
- *Maintain the integrity of services (rule 79(2)(c)(ii))* - by reducing metal loss from corrosion through the operation, maintenance and monitoring of an effective CP system.
- *Comply with a regulatory obligation or requirement (rule 79(2)(c)(iii))* - to ensure AGN operates its assets in line with the requirements set out in AS2832.1 Section 2.2.2.2 where a buried ferrous structure is to maintain a potential on all parts of the structure equal to or more negative than -850mV with respect to a copper/copper sulphate reference electrode.

Appendix A – Risk Assessment

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Option Risk
Risk Untreated	**Likelihood**	*Likely*	*Likely*	*Likely*	*Likely*	*Likely*	*Likely*	*Likely*	***High***
	Consequence	*Medium*	*Minor*	*Significant*	*Significant*	*Minor*	*Medium*	*Minor*	
	Risk Level	*High*	*Moderate*	*High*	*High*	*Moderate*	*High*	*Moderate*	
Residual Risk Option 1	**Likelihood**	*Likely*	*Likely*	*Likely*	*Likely*	*Likely*	*Likely*	*Likely*	***High***
	Consequence	*Medium*	*Minor*	*Significant*	*Significant*	*Minor*	*Medium*	*Minor*	
	Risk Level	*High*	*Moderate*	*High*	*High*	*Moderate*	*High*	*Moderate*	
Residual Risk Option 2	**Likelihood**	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Occasional*	*Occasional*	**LOW**
	Consequence	*Minor*	*Minor*	*Minor*	*Minor*	*Minor*	*Minor*	*Insignificant*	
	Risk Level	*Low*	*Low*	*Low*	*Low*	*Low*	*Low*	*Negligible*	
Residual Risk Option 3	**Likelihood**	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Occasional*	*Occasional*	**MODERATE**
	Consequence	*Minor*	*Minor*	*Minor*	*Minor*	*Minor*	*Medium*	*Minor*	
	Risk Level	*Low*	*Low*	*Low*	*Low*	*Low*	*Moderate*	*Low*	

Appendix B – Detailed Cost Estimate

CP Unit Replacement

The costs below are based on current 2016 costs

DESCRIPTION	Units	Supplier	UOM	$/unit	ITEM COST	TOTAL COST	Comments
NUMBER OF SITES	[redacted]		[redacted]				
[redacted]							
CPU Unit	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
						[redacted]	
[redacted]							
E&I Technician labour (Internal)	[redacted]		[redacted]	[redacted]	[redacted]		[redacted]
Electrical Contractor	[redacted]		[redacted]	[redacted]	[redacted]		
						[redacted]	
MISCELLANEOUS							
Project Management, Administration	[redacted]		[redacted]		[redacted]		[redacted]
						[redacted]	
[redacted]						[redacted]	
[redacted]						[redacted]	

Large Anode Bed Replacement

The costs below are based on current 2016 costs

DESCRIPTION	Units	UOM	$/unit	ITEM COST	TOTAL COST	Comments
NUMBER OF SITES	[redacted]	[redacted]				
MATERIALS - Replacement						
MMO Anodes	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
6 Tonne Loresco SC3	[redacted]	[redacted]		[redacted]		[redacted]
Freight costs from Queensland	[redacted]	[redacted]		[redacted]		[redacted]
Cable	[redacted]	[redacted]		[redacted]		[redacted]
Scotch Casts x 6	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
					[redacted]	
[redacted]						
E&I Technician labour (Internal)	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
Excavate and reinstate anode bed	[redacted]	[redacted]		[redacted]		[redacted]
					[redacted]	
MISCELLANEOUS						
Project Management, Administration	[redacted]	[redacted]		[redacted]		[redacted]
					[redacted]	
[redacted]					[redacted]	
[redacted]					[redacted]	

[redacted]

[redacted]

[redacted]

Small 2A CP Unit / Anode Bed Combination

The costs below are 2014 costs from a project in that year, and then converted to 2016 costs based on CPI movement from December 2014 to December 2015.

DESCRIPTION	Units	UOM	$/unit	ITEM COST	TOTAL COST	Comments
NUMBER OF SITES	[redacted]	[redacted]				
MATERIALS - New						
Anode Bed						
Si Fe Anode	[redacted]	[redacted]		[redacted]		[redacted]
3 Tonne Loresco SC3	[redacted]	[redacted]		[redacted]		[redacted]
Weld Lugs	[redacted]	[redacted]		[redacted]		
Cable	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
Scotch Casts x 1	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
Freight costs from Queensland	[redacted]	[redacted]		[redacted]		[redacted]
CP Unit						
CPU and Cabinet (2A)	[redacted]	[redacted]		[redacted]		[redacted]
					[redacted]	
LABOUR & CONTRACTORS						
E&I Technician labour (Internal)	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
Electrical Contractor	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
Tree Clearing						
Pegging of Easement						
Excavate and install anode bed	[redacted]	[redacted]		[redacted]		[redacted]
Vertical Drilling of anode holes	[redacted]	[redacted]		[redacted]		[redacted]
					[redacted]	

MISCELLANEOUS						
Project Management, Administration	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]
TOTAL BUDGET COST - per site					[redacted]	
[redacted]					[redacted]	
[redacted]					[redacted]	
TOTAL BUDGET COST - per site	[redacted]				[redacted]	
[redacted]					[redacted]	

[redacted]

[redacted]

[redacted]

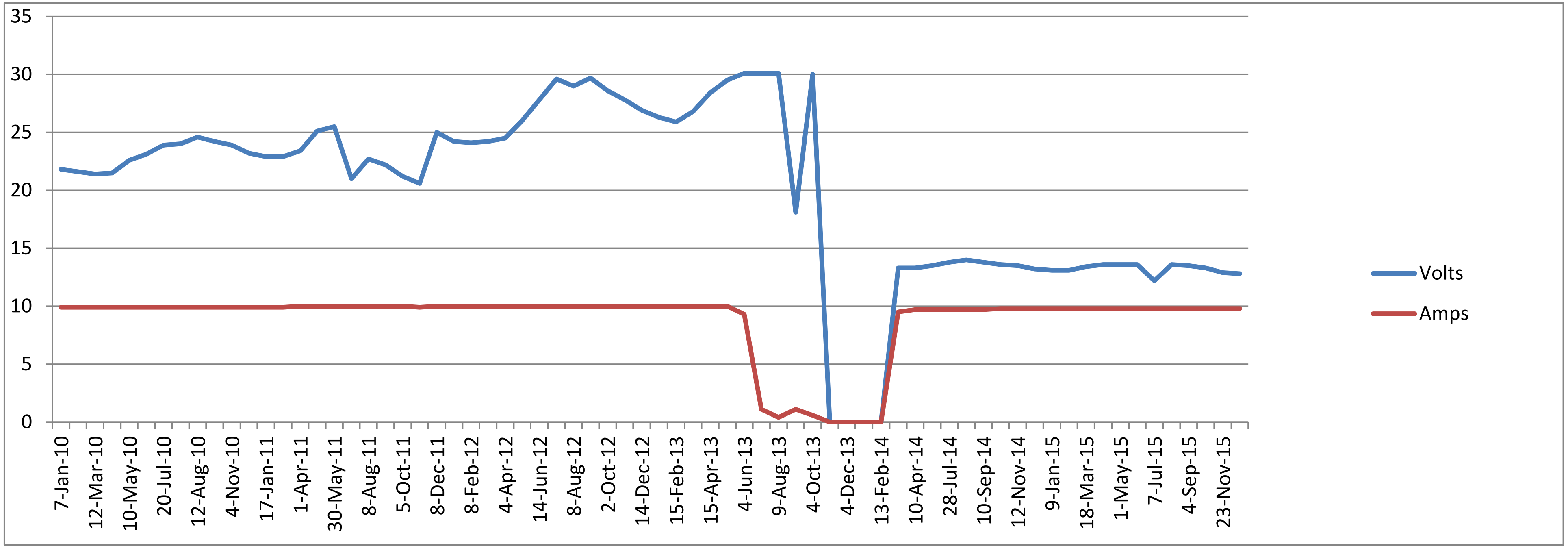
[redacted]

[redacted]

Appendix C – List of Sites for Replacement of CPU and Anode Beds

CPU Number	Address	Suburb	CP Units		Anode Beds	
			Replacement	Year Last Replaced	Replacement	Year Last Replaced
6	Nepean Hwy - Tower Road	Mornington	N		Y	1988
8	South Boundary Road	Pearcedale	Y	1965	N	
22	Tyabb-Mornington Road @ Balcome Creek	Mornington	Y	1978	Y	1978
35	Waringal Park - Beverley Road	Heidelberg	Y	1974	N	
72	Eric Bell Reserve, Messmate Street	Frankston	Y	1980	Y	1980
90	Campbell Street Reserve, Opposite Moray Street	Diamond Creek	Y	1983	N	
103	Fairburn Park, Scenic View Drive	Mt Martha	Y	1983	Y	1983
107	Dallas Brooks Park - Mornington-Tyabb Road	Mornington	Y	1983	Y	1983
110	Darebin Drive, North of Donald Street	Lalor	Y	1983	N	
111	VR Michael Reserve, High Street	Lalor	Y	1983	N	
128	Frankston Reserve, Belvedere Road - Galway Street - Brunel Road	Seaford	N		Y	1984

Appendix D – Example of Anode Bed Failure



Comments:

1. 2010 – 2013 The increasing voltage requirements from the CP unit to hold the current output at the required level indicates that the anode bed is reducing in effectiveness.
2. The failure in 2013 can be clearly seen. This resulted in an extended period of no protection due to the lead time for replacement anode bed equipment, which can be up to 4 months.
3. 2014 – 2015 Following replacement of the anode bed in February 2014, far less voltage output from the CPU is required to hold the required current.

Business Case – Capex V05

Plant & Equipment Upgrade

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	Jarrod Dunn, *Manager System Operations*
Approved By	Andrew Foley, *General Manager Victorian Networks*

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	Tools and equipment wear out through use and periodically require replacement as the equipment becomes unserviceable and ongoing maintenance costs increase. Items are generally replaced on an as-needs basis (e.g. age, condition, spare parts no longer available, new technology). Keeping plant, operational tools and equipment up to date, fit for purpose and in line with advancements in technology, is necessary not only to perform required tasks in the Victorian and Albury gas distribution networks, but also to: • maintain the integrity of the networks; • maintain the safety of the networks by minimising occupational, health and safety (OH&S) risks and health and safety risks to the public. If the correct quality, quantity and type of tools and equipment are not provided then it could result in a potentially severe health and safety event. It could also result in less than efficient field operations due to old, worn out and non-functioning tools and equipment.
Options Considered	The following options have been considered to address the issues outlined above: 1 Option 1: Do Nothing (i.e. continue the use of the existing tools, plant and equipment until each item is no longer able to be used due to obsolescence, breakdown or loss of function). 2 Option 2: Continued purchase of small tools, plant and equipment.
Proposed Solution	Option 2 has been selected as the preferred option because it is necessary to maintain the safety and integrity of services.
Estimated Cost	The proposed capital expenditure (capex) for Option 2 over the next Access Arrangement (AA) Period is $3,818 ($000, 2016).
Consistency with the National Gas Rules (NGR)	The replacement of these assets complies with the new capex criteria in rule 79 of the NGR because: • it is necessary to maintain and improve the safety of services, maintain the integrity of services and comply with OH&S related regulatory obligations (rules 79(2)(c)(i), (ii) and (iii)); 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	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Reliability theme as its implementation will allow AGN to continue providing a highly reliable supply of natural gas to customers by providing personnel tools and equipment that are fit for purpose. More information detailing the results of the stakeholder engagement program is provided in Chapter 3 of the Access Arrangement Information document.

1.3. Background

It is incumbent on network owners/operators to have sufficient items of network related plant, tools and equipment, which are fit for purpose and provide a safe working environment for employees and contractors. Tools and equipment wear out through use and periodically require replacement as the equipment becomes unserviceable and ongoing maintenance costs increase. Items are generally replaced on an as-needs basis (e.g. age, condition such that they are unable to be used safely, spare parts no longer available, new technology).

Keeping plant, operational tools and equipment in serviceable condition, up to date and in line with advancements in technology, is necessary not only to perform necessary tasks, but also to maintain a safe working environment for operating personnel and the public through measures such as:

- The use of current technology (e.g. digital read-outs on equipment) to ensure efficient work practice and minimise errors in circumstances such as gas concentration readings, pressure readings, etc.;
- Minimising the manual handling component of tasks to reduce both the likelihood and consequence of work place injuries, given the high level of manual handling activity involved in the work

Appropriately maintained plant and equipment is necessary for AGN to meet its OH&S obligations to provide a safe place of work for its employees and contractors, and to ensure there are adequate and appropriate tools, plant and equipment necessary to perform the required functions. It is also required to allow the continued safe, reliable supply of gas to consumers, services to be maintained and improved and the integrity of the network to be maintained. The community also expects this type of equipment to be fit for purpose and meet their expectations with respect to matters such as emissions of noise and dust.

If the correct quality, quantity and type of tools and equipment are not provided then it could result in a potentially severe health and safety event and expose AGN's staff and contractors, to increased risk of personnel injury and potential penalties under OH&S legislation. It could also result in less than efficient field operations due to old, worn out and non-functioning tools and equipment.

The type of equipment and tools necessary to adequately perform work on the networks ranges from general excavation equipment to specialised gas detection equipment. Examples of equipment procured during the current regulatory period include:

- Hand held gas detectors for personal use on hazardous sites
- Gas Leak detectors for detection of gas leaks above mains and at above ground facilities

- Cabinets for storage of flammable goods
- Wire cages for correct storage of meters
- Pressure gauges for measurement of gas pressure during maintenance activities
- Fans for use in ventilating underground pits
- Pipe cutters for cutting "windows" in steel pipe to gain access to previously inserted pipe
- Polyethylene stop off and drilling machines for working with polyethylene pipes
- Instruments and tools for use on the SCADA system
- Fork Lift batteries
- General hand tools for operations personnel

Appendix B shows a typical list of these types of assets purchased in financial year 2014/15.

The AER has previously approved expenditure such as this in previous AA reviews, both in South Australia[1] and Victoria[2]. The AER's last determination for the AGN's Victorian and Albury networks approved an allowance of $2,965 ($000, 2011) for this AA period (average of $593 ($000, 2011) per year or $664 ($000, 2016)).

Table 1.3 shows the actual expenditure incurred for this type of equipment during the current AAP.

Table 1.3: Plant & Equipment Current AA Period Actual Expenditure ($000, 2016)

	2013	2014	2015	Annual Average
Approved	650	650	650	650
Actual	1,268	629	393	764

As this table shows, the average expenditure on plant and equipment over the last 3 years has been $764 ($000, 2016).

1.4. Risk Assessment

The result of the risk assessment for the untreated risk is shown in Table 1.4 below. The full risk assessment is included as Appendix A.

[1] In relation to South Australia, the AER noted in its most recent decision that it was "satisfied AGN's capex forecast for other non–distribution system capex is conforming capex that complies with rule 79. We have included $5.0 million ($2014–15, unescalated direct costs) of expenditure in our alternative capex forecast."
See AER, Draft Decision: Australian Gas Networks Access Arrangement 2016 to 2021, Attachment 6 – Capital expenditure, November 2015, page 6-52.

[2] See AER, Access Arrangement Final Decision: Envestra 2013-17, Part 2, March 2013, p. 94.

Table 1.4: Risk Rating

Risk Area	Untreated Risk Level
Health and Safety	High
Environment	Low
Operational	Moderate
Customers	Moderate
Reputation	Moderate
Compliance	Moderate
Financial	Moderate
Untreated Risk Rating	**High**

As this table highlights, the untreated risk rating is High. The primary risk in this case is that if appropriate tools and equipment for the tasks performed are not provided then it will expose operators, customers and the surrounding environment to health and safety risks. Examples of this include:

- Failure to have appropriate gas detectors to adequately detect and classify leaks could result in fatalities and extensive property damage, especially if gas accumulates under buildings and is exposed to an ignition source.
- Failure to provide correct storage of material stocks and tools and equipment can result in hazardous situations with store locations, which have the potential to cause incidents and injury to personnel. Good housekeeping and a tidy workplace contribute to a fit for purpose working environment for personnel, minimising health and safety incidents.
- Failure to protect against manual handling risks can result in significant workplace injuries, primarily to field workers performing seemingly normal duties, including driving, digging, carrying and lifting.
- Failure to provide a safe work environment within hazardous work places could lead to fatality through working in a flammable environment due to not detecting gas leaks.

1.5. Options Considered

AGN has identified the following options to deal with the risks identified in section 1.4:

- Option 1: Do Nothing (i.e. continue the use of the existing tools, plant and equipment until each item is no longer able to be used due to obsolescence, breakdown or loss of function).
- Option 2: Continued purchase of small tools, plant and equipment.

1.5.1. Option 1 – Do Nothing

The first option AGN has identified is to continue the use of the existing tools, plant and equipment until each item is no longer able to be used due to obsolescence, breakdown or loss of function. Once tools and small plant items become unusable or are no longer able to be maintained, they would need to be replaced at generally increased costs for a reactive procurement process. Loss of productivity would ensue during the procurement process, which may also, depending on the item, increase risk within the network. An example of increased risk is if emergency gas stop-off equipment (generally known as stopple equipment) needs to be reactively replaced, lead times for this are extensive. While waiting for the replacement unit, there may be inability to respond to an emergency.

1.5.1.1. Cost/Benefit Analysis

The primary benefit of this option is a reduction in capex, or deferral of it to a reactive procurement environment (which procurement may cost more due to the reactive nature of providing for immediate needs). The costs and risks involved with doing nothing are:

- Increased operating expenditure (opex) for additional maintenance activities to "keep tools and equipment going".
- Decreased productivity associated with inefficient operation, and a gradually degrading and reducing equipment pool.
- Increased OH&S risk associated with operators using older equipment that may not meet the required standards.
- Potential exposure to legislative penalties for failing to provide a safe place of work and litigation if injuries are incurred.

1.5.2. Option 2 – Purchase of Small Tools, Plant and Equipment on an as needed basis

This option continues routine expenditure to provide the appropriate tools and equipment to install, repair and maintain natural gas assets. As existing tools and equipment age, they require replacement in accordance with good business practice.

1.5.2.1. Cost/Benefit Analysis

This option has the following benefits:

- Productivity continues to be maintained at current levels, or improved as newer tools and emerging technologies may promote more efficient ways of carrying out the work.
- Current levels of OH&S performance will be maintained or performance will improve due to improved technologies, equipment design and work methodologies.
- Procurement of items can be effectively and efficiently planned and executed; for example purchasing tools in bulk where applicable to capture volume discounts, or competitively tendering larger items.
- AGN continues to fulfil its obligations to maintain a safe working environment, and will continue to reduce the impact of its operations on the public.

As to the cost of this option, the volume and variety of tools, plant and equipment in use means that continual annual expenditure is required for replacement. As the rate of replacement for such stock cannot be determined accurately (as it depends upon degree of use, harshness of service, technological obsolescence, etc), historical expenditure is commonly used to guide estimates of future expenditure (unless particularly large/new items are forecast). AGN has used an average of the last 3 years of expenditure as a reasonable and best estimate of annual expenditure over the forecast period. As Table 1.3 shows, AGN spent $2,291 ($000, 2016) on plant and equipment over the last three years, which translates to an average annual spend of $764 per year ($000, 2016).

1.6. Summary of Cost/Benefit Analysis

The table below provides a summary of the costs and benefits associated with options 1 and 2.

Table 1.5: Summary of Cost/Benefit Analysis

Option	Benefits	Costs/Risks
Option 1 – Do Nothing	Defers expenditure on plant and equipment	• OH&S related risks and risk to the public's health and safety High. • Increased expenditure on maintaining plant and equipment. • Productivity loss of using old and worn out equipment, and a gradually degrading asset pool • Potential regulatory penalties and exposure to litigation. • Residual risk High.
Option 2 – Plant & Equipment	• Maintains a safe working environment for operating personnel and the public and, in so doing, reduces the health and safety related risks from High to Moderate. • Maintains the integrity of services • Compliance with OH&S obligations and reduced risk of penalties and litigation. • Allows further efficiencies to be sought out. • Reduced expenditure on maintaining existing tools, plant and equipment. • Reduces residual risk to Moderate.	Total cost over the next AA period $3,818 ($000, 2016) or $764 per annum.

1.7. Proposed Solution

1.7.1. What is the Proposed Solution?

Option 2 has been selected because it is the most effective way of managing the safety related risks associated with tools, plant and equipment. AGN will, however, continue to look for opportunities to optimise the life of existing plant and equipment and explore options to improve performance by replacing, upgrading or employing new technology as appropriate.

1.7.2. Why are we Proposing this Solution?

Option 2 has been selected because Option 1 is not really a viable option given that it would:

- expose AGN staff, contractors and the public to the risk of a potentially severe health and safety event;
- compromise the integrity of services and potentially result in the cessation of network operations because AGN would not have access to necessary equipment; and
- result in AGN failing to comply with OH&S requirements.

1.7.3. Forecast Cost Breakdown

The annual cost of this option is forecast to be $764 ($000, 2016), which is the historical average cost over the last 3 years (see Table 1.3). Basing the forecast expenditure on average historical costs for such plant and equipment has been accepted by the AER for the South Australian Access Arrangement.[3]

Table 1.6: Project Cost Estimate ($000, 2016)

	2018	2019	2020	2021	2022	Total
Materials*	764	764	764	764	764	3,818

* Totals may not add due to rounding

1.7.4. Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN considers that the proposed expenditure on tools, plant and equipment is:

- *Prudent* – The expenditure is necessary in order to maintain and improve the safety of services and to maintain the integrity of services to customers and personnel and is of a nature that a prudent service provider would incur.
- *Efficient* – Cost estimates of expenditure are based on the 3 year historical average spend. The estimate allows for maintaining the quantity of plant, equipment and tools at current levels with the expectation that the functionality of some equipment will improve to provide a greater range of applicability and therefore greater risk reduction for the same cost. Further, AGN will continue to look for opportunities to optimise the life of existing plant and equipment and explore options to improve performance. On that basis AGN considers the expenditure to be consistent with the expenditure that a prudent service provider acting efficiently would incur.
- *Consistent with accepted good industry practice* – The tools and equipment already in use and planned under this expenditure are an essential part of performing the required work, and timely replacement and purchase of additional plant, tools and equipment when required, and which is fit for purpose is necessary to continue to perform the required operational activities. Timely replacement is consistent with accepted and good industry practice.
- *Achieves the lowest sustainable cost of delivering pipeline services* – Maintaining suitable plant, tools and equipment is necessary to deliver the required pipeline services and over the

[3] Refer to footnote 1 above.

longer term is more cost effective than maintaining equipment that is no longer fit for purpose and poses a risk to safety and the integrity of services.

The capex can therefore be viewed as being consistent with rule 79(1)(a) of the NGR.

The proposed capex is also consistent with rule 79(1)(b), because the expenditure is necessary to:

- *maintain and improve the safety of services (rule 79(2)(c)(i))* – by providing modern, functional and safe tools and equipment for operations personnel;
- *maintain the integrity of services (rule 79(2)(c)(ii))* – by providing equipment that operates reliably and provides consistent results (eg pressure measurement); and
- *comply with a regulatory obligation or requirement (rule 79(2)(c)(iii))* – to provide a safe place of work for employees.

Appendix A – Risk Assessment

		Health & Safety	Environment	Operational	Customer	Reputation	Compliance & Legal	Financial Impact	Total Score of Risk Level
Risk Untreated	**Likelihood**	Possible	Possible	Possible	Possible	Possible	Possible	Possible	High
	Consequence	Significant	Minor	Medium	Medium	Medium	Medium	Medium	
	Risk Level	High	Low	Moderate	Moderate	Moderate	Moderate	Moderate	
Residual Risk Option 1	**Likelihood**	Possible	Possible	Possible	Possible	Possible	Possible	Possible	High
	Consequence	Significant	Minor	Medium	Medium	Medium	Medium	Medium	
	Risk Level	High	Low	Moderate	Moderate	Moderate	Moderate	Moderate	
Residual Risk Option 2	**Likelihood**	Rare	Rare	Rare	Rare	Rare	Rare	Rare	Moderate
	Consequence	Significant	Minor	Medium	Medium	Medium	Medium	Medium	
	Risk Level	Moderate	Negligible	Low	Low	Low	Low	Low	

Appendix B – List of Equipment Purchased in 2015

Item	Description	CY-2015	$ 2016
1	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]	[redacted]
5	[redacted]	[redacted]	[redacted]
6	[redacted]	[redacted]	[redacted]
7	[redacted]	[redacted]	[redacted]
8	[redacted]	[redacted]	[redacted]
9	[redacted]	[redacted]	[redacted]
10	[redacted]	[redacted]	[redacted]
11	[redacted]	[redacted]	[redacted]
12	[redacted]	[redacted]	[redacted]
13	[redacted]	[redacted]	[redacted]
14	[redacted]	[redacted]	[redacted]
15	[redacted]	[redacted]	[redacted]
16	[redacted]	[redacted]	[redacted]
17	[redacted]	[redacted]	[redacted]
18	[redacted]	[redacted]	[redacted]
19	[redacted]	[redacted]	[redacted]
20	[redacted]	[redacted]	[redacted]
21	[redacted]	[redacted]	[redacted]
22	[redacted]	[redacted]	[redacted]
23	[redacted]	[redacted]	[redacted]

Item	Description	CY-2015	$ 2016
24	[redacted]	[redacted]	[redacted]
25	[redacted]	[redacted]	[redacted]
26	[redacted]	[redacted]	[redacted]
27	[redacted]	[redacted]	[redacted]
28	[redacted]	[redacted]	[redacted]
29	[redacted]	[redacted]	[redacted]
30	[redacted]	[redacted]	[redacted]
31	[redacted]	[redacted]	[redacted]
32	[redacted]	[redacted]	[redacted]
33	[redacted]	[redacted]	[redacted]
	Total ($000)	**$387,155**	**$392,963**

Business Case – Capex V10

Depot Office Refurbishment

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	Robert Davis, *Manager Field Operations & Support*
Approved By	Andrew Foley, *General Manager Victorian Networks*

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	The failure to provide suitable standards of office accommodation that meets occupational, health and safety (OH&S) obligations and other legislative and regulatory requirements can affect productivity and give rise to a range of health and safety risks. Two of the depots/offices that Australian Gas Networks (AGN) currently has in Victoria require work to bring them back up to a suitable standard and to comply with relevant legislative and regulatory obligations. These sites are the Victorian head office at Thomastown and the Albury Depot. An independent report on the Thomastown depot was recently completed by Ardent Architects and found that while the buildings are in relatively good condition, work needs to be carried out to deal with a range of issues, including amongst others, water ingress into the building, the age of the Heating, Ventilating & Air-conditioning (HVAC) system, disabled access compliance and fire service compliance. The office fit-out at Thomastown is also past its serviceable date having last been replaced in 1997 and requires replacement. The office at the Albury Depot also requires refurbishment following sixteen years of continuous occupation with no refurbishment and a new emergency exit needs to be installed. The office also needs to be painted and furniture replaced.
Options Considered	The following options have been considered to address the risks posed by the degradation of the Thomastown and Albury sites: 1 Option 1 "Do Nothing": Under this option the existing depot facilities will operate in "breakdown status", with infrastructure and other facilities repaired on a reactive basis. 2 Option 2: Refurbish the Thomastown and Albury sites over the next AA period.
Proposed Solution	Option 2 has been selected because it is the most cost effective way of dealing with the OH&S and other compliance related risks posed by the current condition of the two sites.
Estimated Cost	The forecast cost of Option 2 is $3,580 ($000 2016) capital expenditure (capex).
Consistency with the National Gas Rules	The proposed refurbishment of Thomastown and Albury depot office buildings complies with the new capex criteria in rule 79 of the National Gas Rules because:

(NGR)	• 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)); and
	• it is justified under rule 79(2)(c) as it is required to:
	  • to maintain and improve the safety of services (79(2)(c)(i));
	  • maintain the integrity of services (79(2)(c)(ii)); and
	  • comply with a regulatory obligation or commitment (79(2)(c)(iii)).

Stakeholder Engagement	A key outcome of the stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered consistent with the Reliability theme. Its implementation will allow AGN to continue to provide a highly reliable supply of natural gas to our customers by providing appropriate support facilities to our operational personnel. Appropriate support facilities for operational personnel are important for attracting and retaining talented personnel which translates into consistent quality of service, enabling our personnel to perform effectively. More information detailing the results of the stakeholder engagement program is provided in Chapter 5 of the Access Arrangement Information document.
Supporting Information	• Supporting Information 1: Ardent Architect Report • Supporting Information 2: Albury Works & Furniture Supplier Quotations

1.3. Background

The failure to provide suitable standards of office accommodation that meets occupational, health and safety (OH&S) obligations and other legislative and regulatory requirements can affect productivity and give rise to a range of health and safety and compliance related risks. Sub-standard office accommodation can also affect a company's ability to attract and retain high quality personnel.

Over the last year it has become clear that two of the depots/offices that AGN currently has in Victoria require work to bring them back up to a suitable standard. These sites are the Victorian head office at Thomastown Site (occupied since 1987) and the Albury Depot (occupied since 2000), which need to be upgraded to ensure that they:

- are fit-for-purpose;
- enable the efficient and effective delivery of ongoing operational requirements; and
- represent current thinking in workplace design to create a productive, healthy and safe working environment, which is focused on delivery of the following key objectives:
  - Operational excellence – equitable and fit-for-purpose property that is developed in a cost-effective and timely manner to enable the efficient and effective operation of the business.
  - Internal Customer satisfaction – high levels of responsiveness to ensure ongoing staff and internal stakeholder satisfaction.

Further detail on the two sites is provided below.

Wood Street Thomastown Site

The Wood Street, Thomastown site plays an important role in supporting the business as the head office for AGN's Victorian operations, both in the long-term and in day to day activities. It houses approximately 200 staff. The Wood Street, Thomastown depot facilities were originally constructed in 1987. The last limited refurbishment work was completed in 1997 when the carpet, workstations, HVAC and a building extension were completed.

The issue of ageing facilities, and failure in some areas, has become evident in the current AA period, with general maintenance not meeting the required standard of upkeep and facilities reaching the end of their operational life. Issues such as damage from water leaks, mechanical plant failure, painting and carpet repairs have required expenditure totaling approximately $40,000 over the two years 2015 and 2016 to temporarily address the immediate risks.

In 2015 AGN engaged Ardent Architects to complete an independent Site Audit and Master Planning Report for the Wood Street Thomastown site utilizing, both their own expertise as well as engaging experts in various engineering disciplines and the Building Code of Australia (BCA) compliance. The scope of the project was to:

1. Deliver a site audit from all relevant disciplines.
2. Identify building fabric issues and suggested rectifications.
3. List building code and Australian Standards non-compliance issues.
4. Develop a master plan showing estimated work station numbers if the building was refurbished to be open plan.
5. Compile reports and drawings for a Quantity Surveyor to provide a quote on costing.

The audit found that while the office building is currently in good condition, the fit-out is now past its serviceable date and requires replacement. The main risks that were identified were: water ingress into the building; the age of the HVAC system; non-compliance with modern disabled-access and fire service requirements. The building complied with the BCA at the time it was constructed and compliance with modern (updated) requirements is not necessary unless significant works are undertaken. Other issues that Ardent Architects noted needed to be addressed include: the electrical system and main switchboard refurbishment, painting, light fitting replacement and upgrade to disabled amenities for toilet/shower. To address these risks, the building infrastructure will need to be refurbished.

The office fit-out and furniture also need to be replaced, given they have been in place since 1997. Complete refurbishment will ensure that the fit-out and furniture continues to be appropriate and ergonomically suitable for a modern office which supports current workforce requirements.

The Ardent Architects report underpins the key assumptions for the Thomastown site and is provided as supporting information to this Business Case.

Albury Depot Site

The Albury facility is a key satellite facility which provides workplace accommodation for those working in the region, housing approximately 20 staff. The office fit out and furniture at this site has not been replaced since first being occupied for use as a depot in 2000 and is starting to degrade. The other issue AGN has identified with this site is that there is only a single emergency exit for the offices on the first floor. Although the building is compliant with the BCA as per the original certificate of occupancy, a single exit from a first floor brings increased risk in the case of emergency.

Work at this site is therefore required to:

- replace the office fit out and furniture;
- install an additional emergency exit to the first floor office; and
- paint the building interior.

1.4. Risk Assessment

A risk assessment has been performed to better understand the risks associated with the degraded buildings. The major risks at each site are summarised below, while Table 1.3 sets out the untreated risks associated with the two sites.

Table 1.3: Risk Rating

Risk Area	Untreated Risk Level
Health and Safety	High
Environment	Low
Operational	Moderate
Customers	Low
Reputation	Moderate
Compliance	Moderate
Financial	Moderate
Untreated Risk Rating	**High**

As this table highlights, the untreated risks associated with the two sites are High, because the health and safety, operational, compliance and financial risks are high. Further detail on the risk assessment can be found in Appendix A.

Wood Street Thomastown Site

The Ardent Architects report on the HVAC system risk profile suggests it will most likely fail in the next 3 – 5 years and would intermittently reduce productivity over a number of days and/or weeks within that period.

An inappropriately controlled air conditioning system in the office environment poses HSE risks (particularly on extreme weather days) and failure of IT equipment which impacts business continuity.

The risk associated with the leaking roof has the potential to damage any new internal works, while also creating HSE issues in terms of slips and falls resulting in lost time to injury (LTI), as well as a range of other risks and general building degradation.

The impact on the above for customers is that the business may be unable to provide continuous quality service to customers as business continuity may be impacted by facilities failure. A possible increased number of LTIs means that operational personnel may not be available to complete AGN's commitments to customers under the Guaranteed Service Level scheme in the Victorian Gas

Distribution Code or in the Retail Market Procedures and would also generate increased business cost from injury management and lost productivity.

A degraded work environment will also impact on AGN's ability to attract and retain high quality personnel, which will have a flow on impact to quality of service provided.

Albury Depot

The Albury depot has only a single path of travel to and from the first floor offices, which means there is an increased risk that staff will be trapped if there is a fire or similar incident where the only existing path of travel is not available.

This depot has also not been refurbished since it was first occupied in 2000. There is a risk with older furniture that it does not meet current ergonomic standards, which can increase the risk of LTI.

1.5. Options Considered

AGN has identified two options to deal with the risks currently posed by the level of degradation at the Thomastown and Albury sites:

- Option 1: Do Nothing – Under this option the existing depot facilities will operate in "breakdown status", with infrastructure repaired on a reactive basis.
- Option 2: Refurbish the Thomastown and Albury depots/offices over the next AA period.

1.5.1. Option 1 – Do Nothing

Under this option, no major capex on building or office refurbishment would occur and any breakdowns or failures would be dealt with on an as-occurs basis.

This option is only sustainable for a short period in the case of the Thomastown Depot because, as the Ardent Architects report advises, if nothing is done the HVAC system will most likely fail during the next AA[1] period. Similarly, the report advises that the water ingress issue should be addressed immediately, and until this is addressed and tested, other refurbishment works should not be undertaken due to the risk of damage.[2] The clear implication is that if nothing is done, further damage will occur to the existing building, continuing the degradation. A degraded work environment will impact on the businesses ability to attract and retain talent, which will have a flow on impact to quality of service provided.

In relation to the Albury Depot, not installing another emergency exit or replacing older furniture is also only sustainable for a short period of time, given the risks posed by these two issues.

1.5.1.1. Cost/Benefit Analysis

While there are no upfront capital costs under this option, AGN will continue to incur costs for repairing facilities on an as-occurs basis, rather than operating in a preventative works mode. In doing so, the business implicitly accepts the cost of facilities failure, which may require activation of a Business Continuity Plan or impact staff health and safety in terms of LTI.

In the case of Thomastown, $40,000 has been spent over the last two years on fixing issues as they arise, so an annual figure of approximately $20,000 could be expected, but increasing over the term of the next AA period due to expected increased degradation and failure rates. A one-off cost of $1.3 million[3] (equipment cost only – business interruption costs not included in this figure)

[1] Supporting Information 1: Ardent Architects Report, p. 4.
[2] Supporting Information 1: Ardent Architects Report, p. 9.
[3] Supporting Information 1: Ardent Architects Report, p. 6 – Table Itemised Risks and Costs.

could also be expected in years 2 or 3 of the next AA period to replace the HVAC system upon expected failure (referred to as the 'entire mechanical system' in the Ardent Report).

In the case of Albury, the annual repair expenditure is estimated to be approximately $4,000 for various repairs based on 2015 costs.

Under this option, the untreated risk will remain High because while some repairs will occur, a large number of issues will not be addressed.

1.5.2. Option 2 – Depot Office Refurbishment

This option will involve refurbishing both the Thomastown and Albury sites in the next AA period.

Other timeframes to complete the work have been considered, including a 3 year option. If the works was carried out over a three year period it would cause significant disruption to the business, and thus a five year timeframe is considered the most prudent. The three year option has not been considered further.

In the case of Thomastown, the refurbishment would focus on the main office building (Building A), as outlined in the Ardent Architects report and commence on the higher risk items identified in this report. The main issues that need to be addressed are: water ingress due to leaking roof, disabled access compliance, essential service upgrade to electrical and fire, replacement of HVAC system in the building, painting of the building, replacement of polycarbonate wall panels and roof, upgrade to disabled amenities for toilet/shower, new main switchboard, replacement of light fittings.

The proposed refurbishment of the Thomastown depot also includes a new office fit-out and replacement of office furniture.

In the case of Albury, the depot refurbishment will involve:

- installing another emergency exit to the first floor office; and
- painting the building interior.
- replacing the office fit out and furniture

1.5.2.1. Cost/Benefit Analysis

The cost of this option is estimated to be $3,580 ($000, 2016), of which $47 ($000, $2016) would be spent on the Albury site and the remainder on the Thomastown site.

The benefits of this option are that:

- The risks associated with the existing facilities will be reduced from High to Low (see Appendix A).
- Operating in a preventative works mode will mean that:
  - repairs will be more cost effective because they can be planned and competitively tendered in a managed environment; and
  - the business significantly reduces the risk of facilities failure, which may otherwise require activation of a Business Continuity Plan[4] or impact staff health in terms of LTI, which can impose costs on the business.
- An improved work environment will also enable AGN to attract and retain high quality personnel.

[4] APA maintains a BCP to minimize interruptions to business as usual activities in the event that disruption at one or more sites occurs. The BCP is not a replacement for normal business activities and processes.

1.6. Summary of Cost/Benefit Analysis

The table below provides a summary of how the options compare in terms of costs, benefits and risks.

Table 1.4: Summary of Cost/Benefit Analysis

Option	Benefits	Costs/Risks
Option 1	Deferral of some capital expenditure.	Increased repair and maintenance costs on a reactive breakdown basis, potentially $20 ($000, 2016) per year, but increasing over the AA period. Approximately $1,300 ($000, 2016) for replacement of HVAC system in years 2 or 3 of the next AA period. Higher risk than Option 2 for personnel injuries and subsequent costs. Residual risk remains High.
Option 2	Completion of full works program for Thomastown and Albury sites. Reduces untreated risk from High to Low. Compliance with OH&S requirements.	$3,580 ($000, 2016)

1.7. Proposed Solution

1.7.1. What is the Proposed Solution?

The proposed solution is Option 2, which involves refurbishing the Thomastown and Albury depot stations in the next AA period in the manner described above.

1.7.2. Why are we Proposing this Solution?

Option 2 is being proposed because it is the most cost effective way of dealing with the OH&S and other compliance related risks posed by the current condition of the Thomastown and Albury depots.

By addressing the building deficiencies and renewing the office fit out and standards of office furniture, AGN will minimise the risk of high cost reactive repairs and maintenance, business interruption due to failure of equipment, customer service levels decreasing, and injuries and the associated costs to personnel and the business. It will provide a modern, ergonomic and safe workplace for personnel within a reasonable timeframe of five years, which will enable staff to be more productive. This option also provides the best opportunity to attract and retain the high quality personnel required to provide a reliable service and the required level of customer service.

Finally, it is worth noting that this option is consistent with the findings from the stakeholder engagement program, which indicated that external customers valued initiatives that improve the safety, reliability and customer service of the network. Consistent with these three insights, upgrading the Thomastown and Albury depots will improve the safety of these buildings, increase the reliability of AGN’s services and improve the quality of customer service.

1.7.3. Forecast Cost Breakdown

The forecast expenditure under Option 2 is shown in Table 1.5. As this table shows, the Albury Depot refurbishment is scheduled to be carried out in 2018, while the Thomastown refurbishment will occur over a five year period. The timing of works at Thomaston is driven by Ardent Architect's finding that many of the facilities have reached the end of their operational life and thus need to be renewed. The facilities at the Albury Depot have not been renewed since 2000 and the site HSE working group has identified a second point of exit from the first floor office as a key safety action.

Table 1.5: Project Cost Estimate ($000, 2016)

	2018	2019	2020	2021	2022	Total
Thomastown	821	822	412	1,334	144	3,533
Albury	47	-	-	-	-	47
Total	**868**	**822**	**412**	**1,334**	**144**	**3,580**

Table 1.6: Major Items ($000, 2016)

Major Item	Estimated Cost
Fit-out	$477
HVAC replacement	$1,200
Furniture	$226
Fire Safety	$228
Other	$1449

In relation to the cost estimate for the Thomastown site, this was prepared by Ardent Architects as part of their report[5].

For the Albury site, quotes were sought from local suppliers and have been provided as Supporting Information to this business case[6]. When the works are carried out, competitive tenders will be conducted.

1.7.4. Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN considers the forecast capex for this project to be:

- *Prudent* – The expenditure is necessary in order to maintain and improve the building integrity and safety of AGN's office accommodation, providing a safe, modern and well maintained workplace for its staff and comply with OH&S requirements and other legislative and regulatory obligations. It is also of a nature that a prudent service provider would incur, particularly on assets that are so critical to the functioning of the Victorian and Albury networks and that have been largely untouched for the last 16-20 years.

5 Supporting Information 1: Ardent Architects Report, pg. 4.
6 Supporting Information 2: Albury Works & Furniture Supplier Quotations.

- *Efficient* – The cost estimate is based on supplier quotations. Before work commences on the two sites, a competitive tender will be conducted to select the contractors that will carry out the work, which is consistent with what a prudent service provider acting efficiently would do.
- *Consistent with accepted good industry practice* – It is incumbent on network owners to provide staff with a suitable working environment which meets OHS standards for office accommodation. The Ardent Architects Report on the Thomastown site has listed a range of issues and risks that are required to be addressed. The Albury Depot also requires refurbishment following sixteen years of continuous occupation. Timely repairs and provision of modern office fit-outs and office furniture when required, meets the requirement of good industry practice.
- *Achieves the lowest sustainable cost of delivering pipeline services* – Delivering the project in the next AA period is the most cost-effective option; the proposed roll-out of the project reduces risks to acceptable levels, whilst being cost-effective. The planned expenditure, by being undertaken in a planned manner, also minimises disruption to delivery of operational services increases safety and minimises the risk of injury to personnel from unsafe facilities.

The capex can therefore be viewed as being consistent with rule 79(1)(a) of the NGR.

The proposed capex is also consistent with rule 79(1)(b), because the expenditure is necessary to:

- *maintain and improve the safety of services (rule 79(2)(c)(i))* - Degrading buildings introduce safety risks to personnel. Particularly at Thomastown, where water ingress into populated areas of the building is a common occurrence, and the HVAC system has the potential to fail within the next 2-3 years.
- *maintain the integrity of services (rule 79(2)(c)(ii))* - Undertaking refurbishment in a planned way will minimise disruption to facilities (e.g. IT equipment), and to personnel performing operational activities, as against the alternative of repairs undertaken reactively, at short notice on a "breakdown basis".
- *comply with a regulatory obligation or requirement (rule 79(2)(c)(iii))* - The proposed expenditure will ensure compliance with the requirements to provide a safe workplace under OHS legislation.

Appendix A – Risk Assessment

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Option Risk
Risk Untreated	**Likelihood**	*likely*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	**HIGH**
	Consequence	*Medium*	*Minor*	*Medium*	*Minor*	*Medium*	*Medium*	*Medium*	
	Risk Level	*High*	*Low*	*Moderate*	*Low*	*Moderate*	*Moderate*	*Moderate*	
Residual Risk Option 1	**Likelihood**	*Likely*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*High*
	Consequence	*Medium*	*Minor*	*Medium*	*Minor*	*Medium*	*Medium*	*Medium*	
	Risk Level	*High*	*Low*	*Moderate*	*Low*	*Moderate*	*Moderate*	*Moderate*	
Residual Risk Option 2	**Likelihood**	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Low*
	Consequence	*Minor*	*Minor*	*Minor*	*Minor*	*Minor*	*Minor*	*Minor*	
	Risk Level	*Low*	*Low*	*Low*	*Low*	*Low*	*Low*	*Low*	

Appendix B – Detailed Cost Estimate

Thomastown Cost Estimate, $3,533 ($000, 2016)

Please refer to Supporting Information 1: Ardent Architects Report.

Albury Cost estimate, $47 ($000, 2016)

Based on supplier quotes provided in Supporting Information 2 and summarised below:

[redacted]

Business Case – Capex V27

Inspection & Refurbishment – Sleeved Railway Casing Pipes

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	Rebecca May, *Manager Planning & Integrity*
Approved By	Andrew Foley, *General Manager Victorian Networks*

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	The current practice for railway crossings requires the installation of a steel sleeve casement pipe at a minimum of 2 meters depth below the rail. The purpose of this sleeve is if the carrier pipe were to leak under the rail, the sleeve and vent would divert and channel the leak away from the rail corridor. This sleeve is cathodically protected, marked with warning signs and is fitted with a vent point to mitigate against any gas build up, should a leak occur in the carrier gas main. Through routine inspections Australian Gas Networks Limited (AGN) has found that previous installation practices and third party activities within rail corridors have resulted in installations not being compliant with current standards and rail authority requirements. Specifically, AGN has identified within the Victorian and Albury networks: • 7 transmission pipelines that appear to have less than the minimum standard cover to comply with current standards and need to be subject to more detailed field surveys to determine the structural integrity of these crossings and assess compliance with current codes and standards; • 14 high pressure sleeved railway crossings that require further structural evaluation to determine the structural integrity of these crossings to assess compliance with current codes and standards; and • 6 high pressure sleeved railway crossings that are missing warning signs, have degraded or non-functional vent stacks, and possible cathodic protection interference between casing pipes and the main gas pipe. If these issues are left untreated, there is a risk that there will be a major gas escape or leak in the rail corridor, which could, in turn, affect public safety, result in third party damage and/or delays to rail services.
Options Considered	The following options have been considered: 1 Option 1 – Do nothing. 2 Option 2 - Inspect 7 transmission and 14 high pressure sleeved railway crossings and remediate 6 high pressure sleeved railway crossings. In relation to Option 2, if the inspection reveals that only minor ancillary works are required, a coordinated program of works will be put in place to repair or replace in conjunction with acquiring the appropriate rail authority permits and approvals. If, however, more significant works are required the works will be carried out in the subsequent Access Arrangement (AA) period (2023-2027).

Proposed Solution	Option 2 has been selected because it is the most cost effective way to mitigate the risks associated with AGN's assets in rail corridors and to demonstrate compliance with AS 2885.
Estimated Cost	The forecast capital expenditure for this project is $368 ($000, 2016)

Consistency with the National Gas Rules (NGR)	The project to refurbish sleeved railway casing pipes complies with the new capital expenditure criteria in rule 79 of the National Gas Rules (NGR) because:
	• 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)); and
	• it is justified under 79(2)(c) as it is required to:
	  • maintain and improve the safety of services (79(2)(c)(i));
	  • maintain the integrity of services (79(2)(c)(ii)): and
	  • comply with a regulatory obligation or requirement (rule (79(2)(c)(iii)).

Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Reliability and Safety themes as its implementation will allow AGN to maintain the safety of our network whilst continuing to provide a highly reliable supply of natural gas to customers by ensuring the integrity of sleeved rail crossings. More information detailing the results of AGN's stakeholder engagement program is provided in Chapter 5 of our Access Arrangement Information document.

1.3. Background

1.2.1. Current situation

AGN's Victorian and Albury networks contain approximately 225 sleeved casing pipes within railway easements containing transmission or distribution pressure assets.

The following table is a summary of the number of crossings by pressure category in AGN's Victorian Gas Networks.

Table 1.3: Crossings by Pressure Category

	Material (Carrier pipe)				
Pressure Category	**Steel**	**Cast Iron**	**PVC**	**Polyethylene**	**Total**
Transmission	23	-	-	-	23
High	153	-	-	40	193
Medium	2	1	-	-	3
Low	2	3	1	-	6
Total	**180**	**4**	**1**	**40**	**225**

Through periodic preventative maintenance and integrity review processes carried out in accordance with AS2885.3 (Cl. 6.2 requires periodic pipeline Integrity Reviews for licensed pipeline assets), seven (7) seven transmission pressure (TP) rail crossings have been identified as potentially not meeting minimum structural requirements of AS2885.1[1] in relation to the impact of the external loads upon pipeline assets. The preferred methodology to evaluate the impact of external loads (AS2885.1 Cl 5.7.3 c) i) and AS2885.1 Appendix V) is the American Petroleum Institute standard, API RP 1102[2] which has been cited for these purposes within AS2885.1

These pipelines have been identified as having less than the minimum standard cover to comply with current standards (AS4799)[3] and potential insufficient girth weld fatigue life based upon structural analysis It was noted during these reviews that all of the rail crossings were found to been built to the standard current at the time of construction – the ROA (Railways of Australia) Code for the Installation of Underground Utility Services and Pipelines within Railway Boundaries, which called for a minimum cover of 1.2m below rail level for encased crossings. Australian Standard, AS4799 has superseded the former ROA (Railways of Australia) Code and now stipulates that a minimum cover of 2m is required below rail level for all new encased gas pipeline crossings. Though this standard is not to be applied retrospectively, there is still a requirement under AS2885 to ensure that the pipeline is structurally fit for purpose over its projected design life. Reduced cover can be accepted for crossings installed under the previous Railway Code provided the pipeline is compliant with the requirements of AS2885. This investigation will assist in confirming the integrity of the carrier pipe at the identified rail crossings and that they are fit for continued service for their remaining design life, so that compliance with AS 2885 and pipeline license requirements can be demonstrated.

Based upon previous integrity investigations as per AS 2885.3 and structural requirements of AS2885.1, to demonstrate compliance, incorporating the structural assessment based upon the application of API RP 1102 for steel pipelines crossing railroads and highways, field surveys will be required for the seven TP crossings. These surveys will entail dig-ups at either side of the rail reserve to determine depth of cover, measure casing wall pipe thickness, assess casing condition and procure soil samples to determine predominate soil type. Soil type testing provides an indication of the relative stiffness of the soil the pipe is embedded and is a factor in predicting pipe deflection. This data will be used as inputs for the completion of engineering calculations, in accordance with API RP 1102, to verify structural compliance of the casing pipe. If compliance cannot be demonstrated then the affected crossing will be scheduled for replacement, which will then be programmed for the following Access Arrangement (AA) period (2023-2027). A summary of the identified crossings is provided in Appendix B.

The periodic preventative maintenance program has also shown that within the greater distribution network, six additional high pressure rail crossings (see Appendix C for a list of locations) require remedial works to, amongst other things:

- Reinstate casing pipe venting pipes and warning signs, due to either damage or removal, to ensure ready identification and diversion of any leaks.
- Relocate or reinstatement of corrosion test point pits due to burial or removal by third parties
- Carry out survey dig-ups to ascertain pipeline and casement 'touch points', where anomalous cathodic protection readings have been recorded and then determine remedial measures based upon outcome of field data.

[1] AS2885.1 Pipelines – Gas and Liquid Petroleum. Part 1: Design and Construction

[2] API RP 1102: Steel Pipelines Crossing Railroads and Highways (American Petroleum Institute)

[3] AS 4799: Installation of Underground Utility Services and Pipelines within Railway Boundaries

- Replace casement pipe sacrificial anode (replaced when identified by potential reading changes indicating that the casement pipe may no longer be adequately cathodically protected).

A further 14 high pressure large diameter (>=200mm) crossings (see Appendix C) have been identified as requiring further structural evaluation. This process involves survey dig ups to determine depth of cover, measurement of casing wall pipe thickness, assessment of casing condition and procurement of soil samples to determine the predominate soil type, so that the structural integrity of the rail crossings can be assessed.

1.4. Risk Assessment

A risk assessment has been carried out using APA's established evaluation criteria (detailed in Appendix A – Risk Assessment) to produce an estimated level of risk, which is summarised in Table 1.4. As this table highlights the untreated risks associated with the four valves has been assessed as "High".

The key risk issues are therefore:

- The potential for gas escapes that affect public safety and reliability of supply. Transmission pipeline sleeved crossings pose the greater risk due to the volume of gas that could be released due to a leak. In addition, if a leak identified was significant, the repair method on a transmission pipeline has the potential to disrupt supply to a large number of consumers
- Interruption or restriction to supply to between 10,000 and 30,000 consumers, if supply from a transmission main needs to be isolated supply in order to make safe and enact a repair. This impact will be dependent upon the time of year an incident occurs and the number of consumers supplied downstream of the affected rail crossing.
- Interruption to supply is not limited to transmission pressure pipelines but can also impact high pressure sleeved crossings that would be deemed critical (diameters greater or equal to 200mm). As they contain large diameter trunk mains which supply a large number of consumers downstream, rail crossings associated with these assets could have high risk consequences due to a leak or shut down to enact a repair.
- Interruption to third party rail services, in the event of a gas leak or escape. There has been a recent incident involving a leak of a 50 year old medium pressure gas main within a railway corridor easement. Due to the proximity of the leak to live electrical overhead lines powering train services, this incident resulted in the shut down of a major northern metropolitan rail service during the evening peak period, resulting in major community service disruption. This shows that, there does not need to be a catastrophic release of gas in order to disrupt rail services, leading to an impact to the reputation of AGN as a prudent asset owner.
- Non-compliance with current regulatory standards (AS2885).

Table 1.4: Risk Rating

Risk Area	Untreated Risk Level
Health and Safety	Low
Environment	Low
Operational	High
Customers	Low
Reputation	Medium
Compliance	Low
Financial	Negligible
Untreated Risk Rating	**High**

1.5. Options Considered

AGN has identified the following options to address the risks outlined in section 1.4:

- Option 1: Do nothing; or
- Option 2: Survey 7 transmission and 14 high pressure sleeved railway crossings and remediate 6 high pressure sleeved railway crossings.

1.5.1. Option 1 – Do Nothing

The first option that AGN has identified is to do nothing, which would mean ignoring the following issues:

- 7 transmission pressure crossings have previously been assessed for their structural suitability for continued service and a number of recommendations for further investigation have been raised. These sites have also been cited within the asset management plans of these licenced assets that have been submitted to Energy Safety Victoria (ESV).
- There are also a number of crossings where, due to the removal or the test points becoming inaccessible, there is no means to take potential readings to determine the effectiveness of the cathodic protection. This increases the risk of not being able to identify whether the main is suitably protected and increases the risk of corrosion and ultimately the potential of a leak. If a leak were to occur as a consequence, this could pose a risk to public safety, loss of public amenity and could impact the security of supply to a significant number of consumers.

While there is no known immediate risk of these crossings failing or leaking at present, choosing not to address the recommendations cited may place AGN in breach of its Safety Case requirements, as the sites have been cited in the licensed asset management plans referenced in AGN’s Safety Case, which requires the endorsement of the ESV.

1.5.1.1. Cost/Benefit Analysis

Not proceeding with this program saves the expense of undertaking the investigation program but this does not defer AGN's responsibilities in the management of the pipeline assets and the residual risk will remain 'High' (see Appendix A).

If a leak or failure were to occur, the cost to remedy in a breakdown situation, including the cost to relight consumers if supply were to be shut down in order to repair the leak,, would be far greater than if the crossing were investigated, or by continuing the regime of corrosion potential measurements (in the cases where the test point is suitable to be read).

1.5.2. Option 2 – Investigation and remediation program

The second option AGN has identified is to:

- Conduct site dig ups on the 7 transmission main crossings to determine depth of cover, measure casing wall thickness, assess casing condition and procure soil samples to determine predominant soil type. These will become inputs for the assessment of the structural integrity of the casing pipe.
- Investigate and assess the 14 high pressure crossings in the same manner.
- Remediate the 6 high pressure crossing sites that have been identified as requiring vent and warning signs and re-establishment of test points for cathodic protection monitoring.

These sites have been selected based upon the action outcomes from the last cycle of MAOP / Integrity Reviews conducted on all of AGN's licensed assets, field remediation referrals and large diameter carrier mains crossings. The larger diameter high pressure crossings have been chosen due to the greater risk associated with loss of downstream consumers if the crossing were to be shut down for repair.

It is anticipated that the 7 transmission surveys will be completed in the first half of the next AA period, with any identified high pressure assets within the vicinity or impacted by the same rail corridor asset, to be scheduled for remediation works. The remedial works required at the six distribution sites, on the other hand, would be undertaken during the middle of the AA period, while the sample investigation works to assess structural integrity at 14 high pressure large diameter mains would be undertaken in the last 3 years of the AA period. Where the survey results reveal that a crossing is non-compliant, further works will be carried out to rectify the issues in the subsequent AA period. Where only minor ancillary works are required to maintain compliance, a coordinated program of works will be put in place to repair or replace in conjunction with acquiring the appropriate rail authority permits and approvals.

It is envisioned that in future AA periods, a program to assess all high pressure and medium pressure rail crossings will be proposed, in order to determine the remaining life of these assets in the same manner as the transmission asset assessment.

1.5.2.1. Cost/Benefit Analysis

The benefit of assessing the transmission crossings provides evidence that the casing is structurally sound. This evidence will form part of the evaluation of the Remaining Life Review of the transmission main itself that it is still fit for service for the remainder of its evaluated design life. This forms part of the life cycle management program for licenced assets under AS2885[4].

[4] AS 2885.3, 2012, Cl 10.3 Remaining Life Review

In the case of the high pressure crossings, remediating venting, signage and cathodic protection will redirect any leakage path away from the rail reserve. This will reduce the risk of rail service closure and community loss of amenity. Making the crossing visible to third parties through signage and venting adds an additional level of protection, in conjunction with asset location information through Dial Before You Dig. This provides an additional safety mitigation measure in the protection from third party damage.

The other main benefit of this option is that the residual risk diminishes from 'High' to 'Medium'.

The cost of this option is estimated as $368 ($000, 2016) over the 5 years of the next AA period (see Section 1.7.3 and Appendix D for more detail).

1.6. Summary of Cost/Benefit Analysis

A summary of the costs and benefits of the two options is shown in Table 1.5 below.

Table 1.5: Summary of Cost/Benefit Analysis ($000, 2016)

Option	Benefits	Costs/Risks
Option 1	No up-front capital expenditure Deferment of cost of programmed work	Increased risk and cost of dealing with an incident as an emergency / breakdown. Potential loss of, or restriction to, supply to thousands of consumers. Non-compliance with current standards. Residual risk High.
Option 2	Data to confirm structural integrity of existing TP rail crossings to support retaining assets in service and assessment of the larger diameter, higher risk HP crossings. Compliance with current Australian Standard (Pipelines) which is a regulatory requirement. Ensure all sites can be identified with signage and CP levels monitored Residual risk Moderate.	$368 ($000, 2016)

1.7. Proposed Solution

1.7.1. What is the Proposed Solution?

The proposed solution is Option 2, which will involve carrying out surveys of the rail encasement pipe, in conjunction with any required refurbishment works, to demonstrate compliance with AS2885 requirements and ensure ready identification and location of AGN's assets within the rail corridor.

The surveys of the casing pipe crossings on 7 transmission and 14 high pressure pipelines will enable documentation of the baseline condition of the casing pipe. The refurbishment work on the 6 high pressure pipelines will entail vent point and sign post replacement and surveys to document depth of cover, soil type, pipe wall thickness and condition.

1.7.2. Why are we Proposing this Solution?

Option 2 is being proposed because it addresses the risk of undetected corrosion in the pipe carrying the gas (carrier pipe), which is within the casing pipe, at these crossings. The transmission pressure mains at these rail crossing points are not suitable for intelligent pigging, which can directly detect pipe wall thickness loss due to corrosion. Thus an indirect method of assessing corrosion in the carrier pipe at these crossings is necessary, and this is usually done by taking cathodic protection readings of the protection levels on the carrier pipe. However, at cased crossings, the casing pipe can 'shield' the carrier pipe from cathodic protection and corrosion can remain undetected as part of this configuration. This investigation will assist in confirming the integrity of the carrier pipe at the identified rail crossings.

For the distribution network, the same issues that have been identified as part of the transmission pipeline integrity assessment apply to many distribution mains (ie structural integrity of casement pipe and potential cathodic shielding of the carrier pipe). 14 high pressure crossings have been selected for initial investigation, based upon the possible volume of a potential leak, the lead time required for procurement of replacement pipe, and the volume of customers potentially impacted in the event of a shut down. Similar to most of the transmission mains, the distribution network is not suitable for intelligent pigging as a measure to ascertain asset condition.

The restoration of existing venting and signage at 6 high pressure crossings will also ensure that utilities and other third parties can readily identify the location of the gas pipe within the rail corridor, which will minimise the risk of third party interference.

AGN has undertaken a comprehensive engagement program to better understand the values of our stakeholders. During this engagement, stakeholders told us that they valued initiatives that improve the safety, reliability and customer service of our network. Consistent with these three insights, refurbishment of the identified rail crossings will increase safety, increase reliability and reduce the amount of customers affected if an incident occurred.

1.7.3. Forecast Cost Breakdown

The cost of carrying out Option 2 is set out in the tables below, as well as the basis of the rates used in the derivation of the costs. The detailed estimate is shown in Appendix D.

As the tables highlight, Option 2 comprises three distinct work streams: transmission crossing investigation, site remediation and distribution mains investigation. The costs of carrying out the transmission and distribution investigations are based on the assumption that a site investigation takes 2 days, with the only difference between the two being site watch and licenced pipeline permit requirements. The remediation works estimates, on the other hand, are based upon a similar program of works recently executed in Shepparton region.

The labour costs have been based upon the engagement of Comdain for the civil works and average traffic management costs, where required, based current schedule of rates, and recent alteration projects.

The rail corridor access costs have been determined based upon the fixed fee charge from the Rail Authority and a provision for labour for the permit issue and site watch requirements, dependent upon the nature of the works required.

Soil testing costs and material testing have been based upon requests for recent projects.

Estimated quantities and timing are:

- Site assessment of 7 transmission sites within the first two years.

- Remediation of 6 distribution and transmission sites to follow the transmission crossing investigation in 2019.
- Investigation and site assessment of 14 large diameter distribution sites in the last three years of the next AA period.

Table 1.6: Transmission Crossing Investigations Estimates ($000, 2016)

	2018	2019	2020	2021	2022	Total
Volume	4	3	-	-	-	7
Unit Cost	15	15 / 22	-	-	-	15 / 22
Total	**60**	**52**	**-**	**-**	**-**	**112**

Table 1.7: Site Remediation Estimate ($000, 2016)

	2018	2019	2020	2021	2022	Total
Volume	-	4	2	-	-	6
Unit Cost	-	10	10	-	-	10
Total	**-**	**40**	**20**	**-**	**-**	**60**

Table 1.8: Distribution Crossing Investigations Estimate ($000, 2016)

	2018	2019	2020	2021	2022	Total
Volume	-	-	4	5	5	14
Unit Cost	-	-	14	14	14	42
Total	**-**	**-**	**56**	**70**	**70**	**196**

Table 1.9: Total Project Cost Estimate ($000, 2016)

	2018	2019	2020	2021	2022	Total
Volume	4	7	4	5	5	-
Total	**60**	**92**	**76**	**70**	**70**	**368**

1.7.4. Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN considers the forecast capex for this project to be:

- *Prudent* – The expenditure is necessary in order to maintain the integrity of services to reduce the incidence of any uncontrolled gas leak or escape within rail service corridors that may affect the safety of services and result in rail service disruption.

- *Efficient* – The field work will be carried out by external contractors, engaged through a competitive tendering process, with the works undertaken in a co-ordinated manner to ensure all services and permits are arranged in planned and staged manner. The coordination and expenditure would be considered consistent with that a prudent service provider acting efficiently would incur.
- *Consistent with accepted good industry practice* – Good industry practice, in accordance with AS2885, requires that identified risks be assessed and action put in place to reduce (or eliminate) risks to as low as reasonably practicable. This project addresses an identified risk and has been developed based upon a prudent approach balancing risk, expenditure and delivery.
- *Achieves the lowest sustainable cost of delivering distribution and pipeline services* – A proactive investigation or maintenance program reduces the risk and escalated cost of addressing incidents on a breakdown basis as well as forming the basis to forecast and better plan for major crossing replacement other remediation measures. This will also reduce the risk associated with the interruption of community services and amenity (cessation of rail services) due to a leak incident.

The capital expenditure can therefore be considered consistent with rule 79(1)(a) of the National Gas Rules. The proposed capital expenditure is also consistent with 79(1)(b), because it is necessary to:

- *maintain and improve the safety of services (79(2)(c)(i))* – the prescribed project works will reinstate visibility of the presence AGN's assets in the rail corridor, providing 3rd parties and the public visibility. This will mitigate the likelihood of the crossing being struck or damaged leading to an uncontrolled escape and possible ignition due to the near proximity of overhead power as a potential ignition source.
- *maintain the integrity of services (79(2)(c)(ii))* – to ensure that the rail crossings are fit for purpose and will perform in encapsulating and diverting any leaks away from the rail corridor and any leak can be managed to ensure that supply can be maintained to downstream consumers, and
- *comply with a regulatory obligation (79(2)(c)(iii))* – For the pipeline assets, AGN can verify that the identified rail crossings are fit for continued service for their remaining design life, so that compliance with AS 2885 and pipeline licence requirements can be demonstrated

Appendix A Risk Assessment

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Option Risk
Risk Untreated "Do Nothing'	**Likelihood**	*Possible*	*Possible*	*Occasional*	*Occasional*	*Occasional*	*Occasional*	*Possible*	**HIGH**
	Consequence	*Minor*	*Minor*	*Significant*	*Minor*	*Medium*	*Minor*	*Insignificant*	
	Risk Level	*Low*	*Low*	*High*	*Low*	*Moderate*	*Low*	*Negligible*	
Residual Risk Option 2	**Likelihood**	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	**MODERATE**
	Consequence	*Minor*	*Minor*	*Significant*	*Minor*	*Medium*	*Minor*	*Insignificant*	
	Risk Level	*Low*	*Low*	*Moderate*	*Low*	*Moderate*	*Low*	*Negligible*	

Appendix B Transmission Sleeve Crossing Sites identified for survey

The Transmission Pressure sites shown in Table B.1 need to be excavated to confirm depth of cover, measurement of casement pipe wall thickness and soil sampling undertaken to ascertain soil type. The currently assumed soil conditions and recorded depths at these sites indicate that the casing pipe girth welds and longitudinal welds (where applicable) exceed fatigue limits. The data gained will provide inputs for engineering calculations to confirm structural compliance with API RP 1102.

Table B.1: Summary of Transmission Survey Locations

Site Number	Licence	Location	Pipeline	Carrier
1	Lic 44	Sale Maffra Road, Sale	**150mm pipeline**	250mm
2	Lic 49	Hillcrest Road, Frankston	**200mm pipeline**	300mm
3	Lic 66	Park St, Brunswick	**250mm pipeline**	400mm
4	Lic 66	Cunningham St, Northcote	**250mm pipeline**	400mm
5	Lic 215	Tramway Road, Morwell	**80mm pipeline**	150mm (to be confirmed)
6	Lic 501	North St, Albury	**200mm pipeline**	300mm
7	Lic 501	Hume Highway, Ettamogah	**200mm pipeline**	300mm

Appendix C Distribution (High Pressure) Sleeve Crossing Sites identified for survey and / or remediation

Table C.1 below provides a summary of the issues at critical high pressure rail crossings and details of the required investigation and actions.

Where a particular site is to be excavated, survey of the casing pipe will also be undertaken to confirm depth of cover, casement pipe wall thickness, and soil sampling undertaken to ascertain soil type, to obtain data to verify structural compliance with API RP 1102.

Table C.1: Summary of High Pressure Rail Crossings Requiring Investigation and / or Remediation

Location	Issue Identified	Action
Disused spur line crossing, Maffra	Vent pipes removed. Unusual potential readings at this location.	Site dig up to confirm assets connected for monitoring. Reinstatement of vent pipes
Para Road, Greensborough	Casing & pipeline equipotential reading	Site dig ups at casement and ground interfaces
Henty Road, Pakenham	Casing & pipeline equipotential reading	Site dig ups at casement and ground interfaces
Clyde Road, Berwick	Test point pit buried, vent pipes cut off	Relocation of test point and vent pipes
High Street, Epping	Test point inaccessible	Relocation of test point
Narre Warren – Cranbourne Rd, Narre Warren	Test point inaccessible (buried by third parties)	Relocation of test point
Glasgow Av, Reservoir	300mm HP steel main	Site dig up for confirmation of structural integrity
Heyington Av, Thomastown	225mm HP steel main	Site dig up for confirmation of structural integrity
Somers Av, Macleod	200mm HP steel main	Site dig up for confirmation of structural integrity
Bolton St, south of Swan St, Eltham	250mm HP steel main	Site dig up for confirmation of structural integrity
Sisely Av, Wangaratta	200mm HP steel main	Site dig up for confirmation of structural integrity
Goulburn Valley Hwy, Shepparton	200mm HP steel main	Site dig up for confirmation of structural integrity
Liddiard Rd, Traralgon	200mm HP steel main	Site dig up for confirmation of structural integrity
Tramway Rd, Morwell	200mm HP steel main	Site dig up for confirmation of structural integrity

Echuca – Kyabram Rd, Echuca	200mm HP steel main	Site dig up for confirmation of structural integrity
Rail Spur in Kyabram – Tongala Rd, Tongala	200mm HP steel main	Site dig up for confirmation of structural integrity
North East rail crossing, Seymour	200mm HP steel main	Site dig up for confirmation of structural integrity
Gulai Rd, Mulwala	200mm HP steel main	Site dig up for confirmation of structural integrity
Bayly St, Mulwala	200mm HP steel main	Site dig up for confirmation of structural integrity
Bosworth Rd, Bairnsdale	200mm HP steel main	Site dig up for confirmation of structural integrity

Appendix D Detailed Cost Breakdown

Table D.1: Typical TP Crossing Site Investigation ($2016)

Item	Unit Cost
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Table D.2: Tramway Road Site Investigation ($2016)

Item	Unit Cost
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Table D.3: Typical HP Crossing Site Investigation ($2016)

Item	Unit Cost
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Table D.4: Typical Remediation Works ($2016)

Item	Unit Cost
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Costs have been rounded to the nearest $1,000 for reporting purposes

Business Case – Capex V34

Replacement of Grove Model 82 Regulators

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	Jarrod Dunn, *Manager System Operations*
Approved By	Andrew Foley, *General Manager Victorian Networks*

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	At the start of the next (2018-2022) Access Arrangement (AA) period there will be 205 Grove 82 regulator units located at 71 field regulators and city gates in Australian Gas Network's (AGN) Victorian Networks. The regulator units at these sites are over 35 years old and direct replacement units are no longer available. Spare parts are also becoming increasingly difficult and costly to obtain and in some cases are just not available. In short, these regulator units are at the end of their useful life and replacement with a different regulator unit is the only option. If replacement does not occur and the Grove 82 regulators fail, then the inability to get spare parts will cause a loss of supply to a downstream network or I&C customer. The successful solution to this issue will ensure that the pressure control components of field regulators and city gates remain current and serviceable, with readily available spare parts for preventative maintenance.
Options Considered	The following options have been considered to deal with risks posed by the Grove 82 regulator units: 1 Option 1: Do Nothing (i.e. continue to maintain the Grove units with spare parts or replace the units on a reactive basis). 2 Option 2: Replace the Grove 82 regulator units at 71 sites with a new, modern and currently available alternative with readily available spares (the Mooney Flowgrid model), over the five year term of the next Access Arrangement (AA) period. 3 Option 3: Replace the Grove 82 regulator unit at 71 sites with a new, modern and currently available alternative with readily available spares (the Mooney Flowgrid model), with 40 sites to be replaced in the upcoming AA period and 31 in the subsequent AA period.
Proposed Solution	The proposed solution is Option 3 because it is the most cost effective option to reduce the risk posed by the Grove 82 regulator units.
Estimated Cost	Option 3 is estimated to cost $3,091 ($000, 2016) over the 10-year period, with $1,742 ($000, 2016) forecast to be incurred in the next AA period.
Consistency with the National Gas Rules	The replacement of Grove 82 regulators at the 71 sites complies with the new capital expenditure (capex) criteria in rule 79 of the National Gas Rules because:

(NGR)	• 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)); and
	• it is justified under 79(2)(c) as it is required to:
	  • maintain the safety of services (79(2)(c)(i)); and
	  • maintain the integrity of services (79(2)(c)(ii)).

Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Reliability and Safety themes as its implementation will allow AGN to maintain the safety of our network whilst continuing to provide a highly reliable supply of natural gas to customers by ensuring this critical equipment is able to function as designed. More information detailing the results of AGN's stakeholder engagement program is provided in Chapter 5 of the Access Arrangement Information document.
Supporting Information	• V34 Supporting Information 1: NPV and Options Analysis • V34 Supporting Information 2: Parts Quotation

1.3. Background

There are currently (September 2016) 221 Grove 82 regulator units located at 75 field regulators and city gates in AGN's Victorian Networks (see Appendix for the location of these units). Figure 1 below shows a Grove 82 regulator.

Figure 1.1: Typical Installed Grove 82 Regulator Unit

The design configuration of the Grove 82 regulator units is such that there are duplicate streams in parallel to guard against failure in one stream. In the event of a failure in one stream, a leak will occur in the local proximity followed by loss of control of the outlet pressure. If no parts are available, the stream will be required to be shut down and supply will rely on a single stream to supply a network area or customer. This situation markedly increases the risk if the second stream fails as the consequence will be a loss of supply rather than just needing to repair equipment. This condition will persist for the length of time it takes to source new and/or used replacement parts. In the event that both supply streams fail, this will result in the facility shutting down and a loss of supply to the network, potentially affecting up to 6,400 customers depending on the location of the failure and the time of year. Industrial and commercial (I&C) customers at risk of shut down include large commercial and industrial sites, such as hospitals, breweries and paper mills, some of which could lose revenue if production has to cease.

Apart from affecting supply to these customers, replacing the unit on a reactive basis can be expected to cost more than a planned replacement program because the discounts that would usually be available for bulk purchases would not be available. The costs of installation may also be higher if the works are not carried out as part of a planned program.

As outlined above, there are currently 221 Grove 82 regulators installed in the Victorian networks. These regulators are over 35 years old and direct replacement units are no longer available. Replacement spares are also becoming increasingly difficult and costly to source as Energy Safety Victoria (ESV) noted in its recent audit of AGN's city gate and field regulator sites (see Appendix C for an extract of an email from the ESV). The ESV's observations are consistent with the feedback AGN has had from suppliers of Grove 82 regulators, which revealed that:

- spare parts are already difficult to source and it will become increasingly difficult to source these parts in the future; and
- the average cost of spare parts for alternative regulators is comparable to the average cost of the spare parts for the Grove 82.

In short, the Grove 82 regulator units are at the end of their useful life and replacement with a different regulator unit is the only option.

In 2015, AGN carried out some investigations to determine what the Grove units should be replaced with. These investigations revealed that the Mooney Flowgrid regulator is the most appropriate alternative replacement. If the Grove units are replaced with the Mooney Flowgrid regulators then minor adjustments to the pipework will be required to allow the new regulators to fit into the existing piping, but the changeover will be a relatively uncomplicated process.

In 2016, AGN had to replace the Grove units at four sites with the Mooney Flowgrid regulator in conjunction with the normal 10 year refurbishment program because the required spare parts for Grove units were not available in the market. By the end of the current AA period, the Grove units at eight sites are expected to be replaced.

This will leave 205 regulators at 71 sites in operation at the beginning of the next AA period.

1.4. Risk Assessment

The untreated risk associated with the Grove units at the 71 sites is shown in Table 1.3 while the full risk assessment is set out in Appendix A. As Table 1.3 highlights, the untreated risk is High.

The principal risk in this case is if a regulator fails unexpectedly and there are no spare parts available to repair it, which is why the Operational risk is rated as High. The failure of the regulator could result in a gas escape, with the potential for ignition, fire and or explosion, which creates a safety risk to the local public and potential for damage to property. It can also be expected to result in an expensive replacement, because a new regulator from a different manufacturer would need to be procured reactively, and there may be an extended period of time for delivery of the new unit, resulting in loss of gas supply to the customer, or network if the failure is at a field regulator site. In the latter case, depending on the location and time of year the supply to up to 6,400 consumers could be affected.

Table 1.3: Risk Rating

Risk Area	Untreated Risk Level
Health and Safety	Moderate
Environment	Low
Operational	High
Customers	Moderate
Reputation	Moderate
Compliance	Moderate
Financial	Moderate
Untreated Risk Rating	**High**

The lack of spare parts for the Grove 82 regulator unit was identified by the ESV in its most recent audit of AGN's city gates, (refer to Appendix C), and will thus be a focus of the ESV going forward. The Compliance risk has thus been rated as Moderate.

1.5. Options Considered

AGN has identified the following options to address the safety and integrity related risks outlined in section 1.4:

- Option 1: Do nothing (i.e. continue to maintain existing Grove 82 regulators with existing spare parts or replace the units on a reactive basis);
- Option 2: Replace Grove 82 regulators at 71 locations over five years with suitable alternative regulator; or
- Option 3: Replace Grove 82 regulators at 71 locations over 10 years with suitable alternative regulator.

Further detail on these options is provided below.

1.5.1. Option 1 – Do Nothing

Under the do nothing option, the existing Grove 82 regulators would continue to be subject to a 10 yearly refurbishment program as part of AGN's normal preventative maintenance schedule. As noted in the background section, discussions with suppliers of Grove 82 regulators have revealed that spare parts are already difficult to source and it will become increasingly difficult to source these parts in the future, meaning that the technical viability of this option is questionable.

1.5.1.1. Cost/Benefit Analysis

This option would see the existing preventative maintenance programme for the Grove 82 regulators continue, at an annual operational cost of $32 ($000, 2016).

The benefit of this option is that it avoids upfront capex. However, if the regulator fails or spare parts are required, then resolving the issue on a reactive basis is likely to be costly and take time to resolve because:

- spare parts are becoming increasingly difficult and costly to obtain; and
- replacement Grove 82 units are not available.

Given the feedback provided by suppliers of Grove 82 regulators, the cost of any reactive measure is likely to be more costly than a planned replacement (i.e. because purchases would be made on an ad hoc basis rather than on a bulk discounted basis).

The main risks under this option are that as spare parts become less and less available:

- when a regulator fails, non-availability of spares will cause a loss of supply to customers; or
- if it occurs at a city gate a network outage to a wide area for an extended time period, while a replacement unit is procured, with a protracted lead time.

This option may also impose costs on I&C customers if it results in a lack of production, and AGN would be subject to costs to relight consumers and payments under the Guaranteed Service Level[1] provisions of the Gas Distribution System Code. The residual risk associated with this option is therefore still considered High.

1.5.2. Option 2 – Replacement of the Grove Units Over 5 Years

This option involves the replacement of the existing Grove 82 regulator units at 71 sites with a new, modern and currently available alternative (Mooney Flowgrid regulator) in the next AA period. Replacing the regulators in the next AA period will involve an accelerated replacement relative to the existing 10-year preventative maintenance program.

1.5.2.1. Cost/Benefit Analysis

Benefits

This option has the benefit that security and reliability of supply is maintained due to the installation of modern regulator units with readily available spare parts, which reduces the risk of supply outages and operational risk to Moderate (see Appendix A). Because this program will be completed over a five year period, the risks are reduced over a shorter time period than Option 3, allowing increased confidence in the safety and integrity of providing distribution services.

Costs

The costs of this option include the cost of replacing the Grove 82 regulator with the Mooney Flowgrid regulators and changing the pipework to accommodate the new regulators. Because the program involves accelerated replacement, additional contract resources will be required relative to the 10-year preventative maintenance program. Additionally, whilst it normally takes two days for the normal 10 year preventative maintenance program, two additional days are required to install the replacement regulator. In addition to these costs, engineering labour will be required to prepare submissions for ESV approval, and confirm the required size of the replacement regulators, for each site.

[1] The Guaranteed Service Level (GSL) payment is intended to ensure that customers are compensated if an energy distribution company does not meet certain minimum performance standards. The amount payable and the conditions under which a GSL payment is triggered are set out in Part E of the Code. For supply interruptions, repeated or lengthy interruptions would incur a GSL of between $150 and $300 per affected customer. Refer to ESC website: http://www.esc.vic.gov.au/document/energy/26123-gas-distribution-system-code-2/.

Table 1.4 sets out the estimated cost of this option over the next AA period, which is ($3,471 ($000, 2016)) and has been estimated using the following assumptions:

- 71 sites are completed over five years, at an average of 14 per year.
- Each site requires 64 hours to complete the replacement, as opposed to 32 hours for normal maintenance. That is, incremental labour of 32 hours (two people for two days).
- The work will be performed by a combination of internal and contract labour. It is assumed that internal labour will be 16 hours per site and contract labour 48 hours.

Hourly rates for internal labour are based on current APA labour rates, and for contractors on current (March 2016) contract rates for AGN's major operations sub-contractors (Comdain).

Table 1.4: Summary of Option 2 Costs ($000, 2016)

Item	Cost
Materials	2,012
Labour (incremental labour, additional to Option 1)	1,164
Disbursements (e.g. Accommodation)	177
Project Management	116
Total	**3,471**

Further detail of this cost estimate is shown in Appendix B.

1.5.3. Option 3 – Replacement of the Grove Units Over 10 Years

Like Option 2, this option involves the replacement of the existing Grove 82 regulator units with a Mooney Flowgrid regulator at 71 sites, but unlike Option 2 the replacement would occur over a ten year period (i.e. over the next two AA periods) rather than a five year period. Under this option, approximately 40 sites will be replaced in the next AA period (2018-2022) in line with their current refurbishment schedule, and 31 in the following AA period (2023-2027). In contrast to Option 2, the replacement will occur in line with the normal 10-year preventative maintenance program, which will enable efficient use of existing resources.

1.5.3.1. Cost/Benefit Analysis

Benefits

In a similar manner to Option 2, the benefits of this option are that:

- security and reliability of supply will be maintained due to the installation of modern regulator units with readily available spare parts; and
- the residual risks are reduced to Moderate (see Appendix A) by the use of equipment that has readily available spare parts.

This option also has the added benefit, however, that the existing preventative maintenance schedule can be utilised, which minimises the requirement for additional resources. When coupled with the fact that the program will be spread over two AA periods, Option 3 costs less to implement than Option 2 and will result in the deferral of approximately half of the capex.

Costs

Like Option 2, the costs of this option include the cost of replacing the Grove 82 regulator with the Mooney Flowgrid regulators, the cost of changing the pipework to accommodate the regulator, the cost of the engineering labour that will be required to prepare submissions for ESV approval, and confirm the required size of the replacement regulators, for each site.

Unlike Option 2, however, the program is scheduled to occur in line with the normal preventative maintenance schedule. This means that the need for external contractors is much lower under this option and the use of internal resources can be maximised. Whilst 32 additional hours is required to install the replacement regulator (refer 1.5.2.1 above), because the work is in line with the normal refurbishment schedule, the use of contractor labour is minimised, at 32 hours per site, with internal labour also at 32 hours per site.

The total cost of this option is estimated to be $3,091 ($000, 2016), which is $379 ($000, 2016) (or 11%) lower than the cost of Option 2. It is also worth noting, there is not a significant reduction in risk with the five-year program compared to the 10-year program, with both options resulting in a residual risk rating of Moderate. The accelerated process outlined in Option 2 therefore provides little benefit over the next AA period, relative to Option 3.

Of the $3,091 ($000, 2016), $1,741 ($000, 2016) will be spent in the next AA period. The costs that are expected to be incurred in the next AA period are set out in Table 1.5, which are based on the following assumptions:

- 71 sites are completed over 10 years, 40 in the next AA period (approximately eight per year) and 31 in the following AA period (2023-2027).
- Each site requires 64 hours to complete the replacement, as opposed to 32 hours for normal maintenance. That is, incremental labour of 32 hours.
- The work will be performed by a combination of internal and contract labour. Internal labour is maximised at 32 hours per site and contract labour 32 hours.
- Hourly rates for internal labour are based on current APA labour rates, and for contractors on current (March 2016) contract rates for AGN's major operations sub-contractors (Comdain).

This approach will leave 31 sites to be completed in the following AA period (2023-27), at an estimated cost of approximately $1,350 ($000, 2016) over the term of the next AA period.

Table 1.5: Summary of Option 3 Costs ($000, 2016)

Item	Cost
40 Sites for Replacement:	
Materials	1,134
Labour (incremental labour, additional to Option 1)	462
Disbursements (eg Accommodation)	100
Project Management	46
Total	**1,742**

1.6. Summary of Cost/Benefit Analysis

A summary of the costs and benefits of the two options is shown in Table 1.6 below.

Table 1.6: Summary of Cost/Benefit Analysis

Option	Benefits	Costs/Risks
Option 1 – Do Nothing	No upfront capex required.	The greatest risk with this option is that the inability to get spares may cause a loss of supply to an I&C customer or potentially a network outage for an extended time, while a replacement unit is procured, with a protracted lead time. The residual risk associated with this option is High On-going annual opex cost of $32 ($000, 2016)
Option 2 – Replacement of Grove units at 71 locations over 5 years	The benefits of this option are that: • Security and reliability of supply is maintained due to the installation of modern regulator units with readily available spare parts. • The residual risk associated with the Grove 82 regulators is reduced to Moderate. The risk is reduced at a faster rate than Option 3.	Capex of $3,471 ($000, 2016) over the five years of the next AA period. The cost is higher than Option 3 due to the additional use of contactors for the increased workload of completing the program in five years instead of 10.
Option 3 – Replacement of Grove units at 71 locations over 10 years	• Security and reliability of supply is maintained due to the installation of modern regulator units with readily available spare parts. • The residual risk associated with the Grove 82 regulators is reduced to Moderate, but at a slower rate than Option 2.	Capex of $3,091 ($000, 2016) of which $1,742 ($000, 2016) will be spent in the next AA period.

A formal cost benefit analysis has been undertaken to quantitatively determine the least cost option. The results of this analysis are shown in Table 1.7 below, which compares the net present value of the costs of the three options outlined above over a 25 year period,[2] i.e.:

- Option 1: Do Nothing;
- Option 2: Institute a replacement program over the five years of the next AA Period; and
- Option 3: Institute a replacement program over the ten years of the next and following AA Periods.

Before examining this table, it is worth noting that it has not been possible to build in the costs associated with the following risks under Option 1:

- if a regulator fails, spare parts may not be available, which will result in a loss of supply to customers, relighting costs and Guaranteed Service Level payments; and
- if the failure occurs at a city gate it will result in a network outage to a wide area for an extended period, which could also give rise to additional relighting costs and Guaranteed Service Level payments.

[2] An analysis period of 25 years has been chosen to account for 2 x 10 year preventative maintenance cycles.

The cost of this option presented in this table therefore understates the full cost of this option. Further detail on the costs assumed under each option is provided in Appendix B.

Table 1.7: Comparison of Options ($000, 2016)

		Next AA Period					Subsequent AA Periods	
	NPV 2016	**2018**	**2019**	**2020**	**2021**	**2022**	**2023 - 2042**	**Total**
Option 1	-1,765	-76	-32	-119	-32	-119	-2,344	**-2,723**
Option 2	-3,057	-733	-684	-684	-684	-684	N/A	**-3,470**
Option 3	-2,542	-348	-348	-348	-348	-348	-1,350	**-3,091**
Discount Rate (real pre-tax WACC)	**3.14%**							

As this table shows, Option 1 is the lowest cost option, but as noted above the estimated cost of this option understates the full cost of this option because it does not take into account all of the costs associated with the risks under this option, which are rated as High. Given the residual risks associated with this option, it is not considered a feasible option.

Of the remaining two options, Option 3 is a lower cost option than Option 2 and will also result in the residual risk being reduced to Moderate. While the rate of risk reduction under this option is slower under this option than Option 2, the risks can be managed by replacing those regulators at greatest risk first. This option is therefore preferable to both Option 2 and Option 1.

1.7. Proposed Solution

1.7.1. What is the Proposed Solution?

AGN proposes to implement Option 3, which will involve the replacement of Grove 82 regulators at 71 locations over the next two AA periods with regulators at 40 locations to be replaced in the next AA period.

1.7.2. Why are we Proposing this Solution?

Option 3 is being proposed because it is the most cost effective way to reduce the risk associated with the Grove 82 regulators to as low as reasonably practicable, maintain the safety and integrity of services and ensure security of supply to I&C customers and domestic customers on networks that are supplied via city gates and field regulators. It will also:

- result in lower costs over the longer term because parts are more readily available than the parts required for the Grove 82 regulator unit;
- maximise the life of the existing regulators;
- enable the majority of the work to be carried out by internal resources, which reduces the labour cost component of the program (i.e. because the replacement is aligned with the existing 10-year refurbishment program);

- limit disruption to other work, because the program can be delivered within the existing 10-year preventative maintenance program; and
- reduce the residual risks associated with the Grove 82 regulators from High to Moderate.

Additionally, the adoption of a slower, long term program allows management to develop and put in place long term programs in other areas to ensure operational efficiencies are optimised. A five year program will require increased management resources and result in reduced focus on developing other improvements to operational efficiency, with the possible result of more reactive responses in other areas of work, with resultant increased costs.

AGN has also undertaken a comprehensive stakeholder engagement program to better understand the values and needs of our stakeholders and customers. During this engagement, customers told us that they valued initiatives that maintain the reliability and improve the safety of our network. Consistent with the above insight, ensuring the correct functioning of key pressure control equipment at major pressure let-down facilities avoids incidents from breakdown of this equipment and contributes to the provision of a reliable and safe supply of natural gas.

Our stakeholder engagement program found that given the very high level of gas supply service, it is understandable that no participants supported investments to deliver a level of reliability beyond what they currently experience. Although participants did not want to invest in improving reliability, they do value the current levels, and are supportive of investment that maintains it. During our workshops, participants also told us that they do not want to see an increased level of outages, rather they would like the status quo to continue.

1.7.3. Forecast Cost Breakdown

The cost of the proposed replacements is shown in Table 1.8 below, and further detail is provided in Attachment B. As this table shows, Option 3 is forecast to cost $1,741 ($000, 2016) in the next AA period (or $3,091 ($000, 2016) in total). This forecast is based on the following assumptions:

- *Materials* – The cost of replacement regulators has been based on the results of a tender process from suppliers, with selection criteria including technical suitability and price.
- Labour
  - *Internal labour* – These costs are based on standard internal labour rates from AGN's operator, APA Group.
  - *External labour* – These costs are based on standard contract labour rates, which are regularly renewed through a competitive tender process, to support the requirement of an additional 32 hours for regulator replacement as opposed to maintenance.
- *Disbursements* – Provision has also been made in the cost estimate for travel and accommodation for sites located outside the metropolitan area.

As noted above the proposed replacements are planned to be undertaken as part of the routine 10 yearly maintenance schedule of the applicable sites, with approximately eight sites to be replaced each year in the next AA period). As a site comes up for its 10 yearly preventative maintenance, the new regulator will be installed in place of the existing one. Other than minor pipework changes, the replacement regulators have been selected so that they can simply replace the existing, and no other modifications are necessary.

Table 1.5: Project Cost Estimate ($000, 2016)

	2018	2019	2020	2021	2022	Total
Volume	8	8	8	8	8	40
Unit Cost	43.5	43.5	43.5	43.5	43.5	-
Total	**348**	**348**	**348**	**348**	**348**	**1,742**

Note: Totals may not add due to rounding.

1.7.4. Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN considers the forecast capex for this project to be:

- *Prudent* – AGN has examined a number of options to address the issue of aging regulators for which spare parts are becoming harder and harder to obtain. It has reviewed the costs and risks associated with each option and selected the least cost option, and one that can be delivered within the existing routine maintenance schedule, representing minimum disruption to delivery of network services. For this reason the expenditure can be regarded as prudent.
- *Efficient* – There is not a significant reduction in risk for a five-year program compared to a 10-year program, and so an accelerated process is not proposed. The proposed expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur. The manner in which AGN intends the replacement to be carried out (i.e. utilising the established routine maintenance schedule to undertake the replacements and utilising existing operational personnel), can also be considered efficient.
- *Consistent with accepted good industry practice* – it is incumbent on distribution operators to ensure that installed assets are operated and maintained in accordance with our safety and operating plan (Australian Standard AS4645[3]). Reducing the risk associated with these regulator units to as low as reasonably practicable in a manner that balances cost and risk is also consistent with Australian Standard AS4645 and therefore in keeping with accepted and good industry practice.
- *Achieves the lowest sustainable cost of delivering pipeline services* – Carrying out the replacement program over the next two AA periods is the most cost effective option, because it allows the existing maintenance program and existing operational labour to be used to carry out the work. Replacing the Grove 82 with the Mooney Flowgrid will also result in lower costs over the longer term.

The capex can therefore be viewed as being consistent with rule 79(1)(a) of the NGR.

The proposed capex is also consistent with rule 79(1)(b), because the expenditure is necessary to:

- maintain and improve the safety of services (rule 79(2)(c)(i)) by ensuring modern components with readily available spare parts to avoid the risk of gas outages due to extended procurement times for reactive replacement of failed regulators;

[3] AS 4645.1 2008, Section 2.4.

- maintain the integrity of services (rule 79(2)(c)(ii)) by being able to continue to provide a reliable gas supply unhampered by difficulties and delays in sourcing replacement parts and regulator units; and
- maintain AGN's capacity to meet existing levels of demand for services existing at the time the capex is incurred (rule 79(2)(c)(iv)) by avoiding service degradation due to the inability of replacing failed components.

Appendix A Risk Assessment

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Option Risk
Risk Untreated	**Likelihood**	*Possible*	*Occasional*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*High*
	Consequence	*Medium*	*Minor*	*Significant*	*Medium*	*Medium*	*Medium*	*Medium*	
	Risk Level	*Moderate*	*Low*	*High*	*Moderate*	*Moderate*	*Moderate*	*Moderate*	
Residual Risk Option 1	**Likelihood**	*Possible*	*Occasional*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*High*
	Consequence	*Medium*	*Minor*	*Significant*	*Medium*	*Medium*	*Medium*	*Medium*	
	Risk Level	*Moderate*	*Low*	*High*	*Moderate*	*Moderate*	*Moderate*	*Moderate*	
Residual Risk Option 2	**Likelihood**	*Unlikely*	*Possible*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Moderate*
	Consequence	*Medium*	*Minor*	*Medium*	*Minor*	*Minor*	*Medium*	*Minor*	
	Risk Level	*Moderate*	*Low*	*Moderate*	*Low*	*Low*	*Moderate*	*Low*	
Residual Risk Option 3	**Likelihood**	*Unlikely*	*Possible*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Moderate*
	Consequence	*Medium*	*Minor*	*Medium*	*Minor*	*Minor*	*Medium*	*Minor*	
	Risk Level	*Moderate*	*Low*	*Moderate*	*Low*	*Low*	*Moderate*	*Low*	

Appendix B Detailed Cost Estimate

This appendix presents the details cost estimates for Options 2 and 3.

Option 2 – Replacement of Grove 82 Regulators over 5 years

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Option 3 – Replacement of Grove 82 Regulators over 10 years

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Appendix C Extract from ESV Email

From: Bill Holden [mailto:bholden@esv.vic.gov.au]
Sent: Thursday, 4 February 2016 4:04 PM
To: Ferrari, Roberto
Cc: Mignone, Ralph (AGN); Dunn, Jarrod; Foley, Andrew; Mark Swida
Subject: RE: Summary of Findings from ESV audit of AGN City Gates and Field Regulators

Hi Roberto

As promised, please find the below information that should assist. We didn't get through every finding but the locations of the critical ones have all been identified and these are the ones you will most probably be concerned with in the immediate term.

Observations (OB):

Design/Signage/Drawings Grouping:

1. Grove Flexflo 80, 81, 82, 83 regulators used – 6 sites – There are no soft parts available on the market to support these type of regulators.

- Maffra FR P4-101;
- Wangaratta CG P4-108;
- Benalla CG P4-107;
- Seymour CG P4-106;

Appendix D Sites Where Grove Replacement is Required

Site Name	Inlet Pressure
ABBOTTS RD DANDENONG SOUTH 3175 VIC	TP
ALFRED ST NORTH MELBOURNE 3051 VIC	TP
BAYVIEW RD HASTINGS 3915 VIC	TP
BLYTH ST DOCKLANDS 3008 VIC	TP
BLYTH ST DOCKLANDS 3008 VIC	TP
BROADFORD FLOWERDALE RD BROADFORD 3658 VIC	TP
CONTINGENT ST TRAFALGAR 3824 VIC	TP
DAWSON ST SALE 3850 VIC	TP
DUNNS RD MORNINGTON 3931 VIC	TP
EDGARS RD LONGWARRY 3816 VIC	TP
FAIRFIELDPARK DR FAIRFIELD 3078 VIC	TP
FIRMINS LANE HAZELWOOD NORTH 3840 VIC	TP
FITZSIMONS LANE LOWER PLENTY 3093 VIC	TP
FRANKSTON FLINDERS RD TYABB 3913 VIC	TP
GERALD ST TYABB 3913 VIC	TP
GILCHRIST ST SHEPPARTON 3630 VIC	TP
GOVERNMENT RD TALLAROOK 3659 VIC	TP
GREENS RD DANDENONG SOUTH 3175 VIC	TP
HARBOUR ESP DOCKLANDS 3008 VIC	TP
HIGH ST HASTINGS 3915 VIC	TP
HUME ST WODONGA 3690 VIC	TP
HUON PARK RD CRANBOURNE NORTH 3977 VIC	TP
KOO WEE RUP RD PAKENHAM 3810 VIC	TP
MACAULAY RD NORTH MELBOURNE 3051 VIC	TP
MAHONEYS RD RESERVOIR 3073 VIC	TP
MELBOURNE RD WODONGA 3690 VIC	TP
MIDLAND HWY BENALLA 3672 VIC	TP
OHERNS RD EPPING 3076 VIC	TP
OLD DOOKIE RD SHEPPARTON 3630 VIC	TP
PHILLIP ST RESERVOIR 3073 VIC	TP
REX AVE ALPHINGTON 3078 VIC	TP
SPENCER ST MELBOURNE 3000 VIC	TP
STATION ST MAFFRA 3860 VIC	TP
TELEGRAPH RD WHITEHEADS CREEK 3660 VIC	TP
THURGOONA DR THURGOONA 2640 NSW	TP
TRAMWAY RD MORWELL 3840 VIC	TP
TUCKERS RD CLYDE NORTH 3978 VIC	TP
WALLAN WHITTLESEA RD WALLAN 3756 VIC	TP
WANGARATTA WHITFIELD RD WANGARATTA 3677 VIC	TP
WESTERNPORT RD DROUIN SOUTH 3818 VIC	TP
WOOD STREET THOMASTOWN 3074 VIC	TP
WOOLLEYS RD CRIB POINT 3919 VIC	TP
AMBON ST PRESTON 3072 VIC	HP
BANYULE RD ROSANNA 3084 VIC	HP

Site Name	Inlet Pressure
BARKLY ST MORNINGTON 3931 VIC	HP
BATMAN AVENUE MELBOURNE 3000 VIC	HP
BEECH STREET THOMASTOWN 3074 VIC	HP
BELEURA HILL RD MORNINGTON 3931 VIC	HP
BOUNDARY RD NORTH MELBOURNE 3051 VIC	HP
CHARNFIELD COURT THOMASTOWN 3074 VIC	HP
CHURCH ST RESERVOIR 3073 VIC	HP
COOLEY AVE MACLEOD 3085 VIC	HP
COOLIBAR AVE SEAFORD 3198 VIC	HP
DUNSTANS COURT THOMASTOWN 3074 VIC	HP
EXHIBITION ST MELBOURNE 3000 VIC	HP
GLEADELL ST RICHMOND 3121 VIC	HP
GOWER ST PRESTON 3072 VIC	HP
GREENSBOROUGH RD MACLEOD 3085 VIC	HP
GREENSBOROUGH RD WATSONIA 3087 VIC	HP
GRIEVE ST MACLEOD 3085 VIC	HP
HICKFORD ST RESERVOIR 3073 VIC	HP
JENSEN RD PRESTON 3072 VIC	HP
JONES PL RICHMOND 3121 VIC	HP
LARGS ST SEAFORD 3198 VIC	HP
MACAULAY RD NORTH MELBOURNE 3051 VIC	HP
MCCRAE RD ROSANNA 3084 VIC	HP
MCVEAN ST BRUNSWICK 3056 VIC	HP
MORWELL AVE BUNDOORA 3083 VIC	HP
NORTH RD RESERVOIR 3073 VIC	HP
PASCHKE CRES LALOR 3075 VIC	HP
SPENCER ST MELBOURNE 3000 VIC	HP
ST JAMES RD ROSANNA 3084 VIC	HP
STATION STREET THOMASTOWN 3074 VIC	HP
STAWELL ST SALE 3850 VIC	HP
STEWART ST BRUNSWICK EAST 3057 VIC	HP
STEWART STREET THOMASTOWN 3074 VIC	HP
VICTORIA PDE EAST MELBOURNE 3002 VIC	HP
YORK ST MORNINGTON 3931 VIC	HP
TP	**42**
HP	**37**
TOTAL	**79**

Note: It is estimated that 8 of the above sites will require the Grove units to be replaced on a reactive basis within the current AA period, leaving 71 with Grove units still in place.

Business Case – Capex V35

I&C Metersets – Fisher 298 Replacement

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	Jarrod Dunn, *Manager System Operations*, APA Group
Approved By	Andrew Foley, *General Manager Victorian Networks*, APA Group

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	There are currently 204 Fisher 298 regulator units located at 51 industrial and commercial (I&C) customer metering and a number of Field Regulator sites (the Field Regulator sites are used to supply other customers in the network). The existing Fisher 298 regulators at these sites are over 35 years old and routine replacement spares are becoming increasingly expensive and difficult to source because the parts are no longer being mass produced. While the supplier has indicated that it can manufacture specific orders on a one-off basis, the cost of this option is much higher than the cost of obtaining parts for other regulators and also requires a longer lead time. Failure of a Fisher 298 regulator unit and the inability to readily obtain spare parts will cause a loss of supply to an I&C customer, or potentially a network outage if it occurs at a Field Regulator site where one is installed. It will therefore affect Australian Gas Networks (AGN) ability to meet existing levels of demand and maintain the safety and integrity of services. The successful solution of this issue will ensure that the pressure control components of I&C meter sets and district regulators remain current and serviceable, with readily available spare parts for preventative maintenance.
Options Considered	The following options have been considered: 1 Option 1: Do Nothing (i.e. continue to maintain the Fisher 298 with spare parts) 2 Option 2: The replacement of **all** the existing Fisher 298 regulator units at the 51 sites with a new, modern and currently available alternative with readily available spares, over the next Access Arrangement (AA) period. 3 Option 3: The replacement of the Fisher 298 regulator units with a new, modern and currently available alternative with readily available spares over a 10-year period, with 26 sites to be completed in the upcoming AA period and 25 in the subsequent AA period. AGN has carried out some investigation of the regulator units that could be used in place of the Fisher 298 under options 2 and 3 and found the Fisher EZR to be the most appropriate because it is a low cost option and requires no modification to the pipeline.
Proposed Solution	The proposed solution is Option 3 because it is the most cost effective option.
Estimated Cost	The forecast capital expenditure for Option 3 is $1,343 ($000, 2016) over a 10-year

	period, with $685 ($000, 2016) forecast to be incurred in the next (2018 – 2022) Access Arrangement (AA) period and the remainder in the subsequent AA period.

Consistency with the National Gas Rules (NGR)	The replacement of Fisher 298 regulators at I&C meter sets and Field Regulator sites complies with the new capex criteria in rule 79 of the National Gas Rules because:
	• 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)); and
	• it is justified under 79(2)(c) as it is required to:
	  • maintain the safety of services (79(2)(c)(i));
	  • maintain the integrity of services (79(2)(c)(ii)), and
	  • maintain the capacity to meet existing levels of demand (79(2)(c)(iv)).

Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Reliability and Safety themes as its implementation will allow AGN to maintain the safety of the network whilst continuing to provide a highly reliable supply of natural gas to customers by ensuring that the equipment is fit for purpose. More information detailing the results of AGN's stakeholder engagement program is provided in Chapter 5 of the Access Arrangement Information document.
Supporting Information	• Supporting Information 1 : V35 Supporting Information 1 (NPV and Options analysis).xls • Supporting Information 2: Quotation Fisher 298 spares and Fisher EZR Regulators

1.3. Background

There are currently 204 Fisher 298 regulator units located at 51 industrial and commercial (I&C) customer metering and a number of Field Regulator sites (the Field Regulator sites are used to supply other customers in the network)[1].

The existing Fisher 298 regulators at these sites are over 35 years old and routine replacement spares are becoming increasingly expensive and difficult to source because the parts are no longer being mass produced. AGN has had some discussions with the supplier of Fisher 298 regulators who has noted that while it may be possible to manufacture specific orders on a one-off basis, this will require a longer lead time. The supplier also noted that:

- The cost of spares parts for the Fisher 298 is comparable to the cost of replacing the regulator with an alternative regulator approximately $16 ($000, 2016) per site versus replacement spare parts $12 ($000, 2016) per site); and
- The cost of spare parts for alternative regulators is approximately 30% of the cost of the spare parts for the Fisher 298 (approximately $5 ($000, 2016) per site versus $12 ($000, 2016) per site).

The Fisher 298 typically has duplicate streams in parallel (but can also be single stream) to guard against failure in one stream. In the event of a failure in one stream, a leak will occur in the local proximity followed by loss of control of the outlet pressure. If no parts are available, the stream will be required to be shut down and supply will rely on a single stream to supply a network area or customer. This situation markedly increases the risk by a higher consequence if the second

[1] A Field Regulator is a site at which pressure control equipment provides a gas supply from a higher pressure network (transmission or high pressure) into a lower pressure network (medium or low pressure). They can be either above or below ground.

stream fails. If the whole regulator fails then it will result in a loss of supply to an I&C customer, or potentially a network outage if it occurs at a Field Regulator where one is installed, affecting typically up to 6,500 residential, commercial and industrial customers. Because spare parts will not be readily available, the loss of supply or network outage could persist for some time. Failure of the regulator could also result in a gas escape, which poses a risk to property and human health and safety.

Given the risk posed by the lack of readily available and increasingly expensive spare parts, AGN has obtained quotes on several alternative replacement regulator units that perform the same function as the existing Fisher 298 units. Through this process AGN has identified the Fisher EZR regulator as the most appropriate replacement option because it is a low cost option and requires no modifications to pipework or other modifications. The successful solution of this issue will ensure that the pressure control components of industrial and commercial meter sets and Field Regulators are fit for purpose and serviceable, with readily available spare parts for preventative maintenance.

1.4. Risk Assessment

This risk assessment associated with this untreated risk is shown in Table 1.3 below (see Appendix A for the full risk assessment). As this table highlights, the untreated risk associated with the Fisher 298 regulators is High, because they pose a high operational risk.

Table 1.3: Risk Rating

Risk Area	Untreated Risk Level
Health and Safety	Moderate
Environment	Low
Operational	High
Customers	Moderate
Reputation	Moderate
Compliance	Moderate
Financial	Moderate
Untreated Risk Rating	**High**

As noted above, the Fisher 298 regulator has duplicate streams (in most cases) that run in parallel to guard against failure in one stream. In the event of a failure in one stream, a leak will occur in the local proximity followed by loss of control of the outlet pressure. If no parts are available, the stream will be required to be shut down and supply will rely on a single stream to supply a network area or customer. This situation markedly increases the risk by a higher consequence if the second stream fails. This condition will persist for the length of time it takes to source new and/or used replacement parts. In the event that both supply streams fail, this will result in the facility shutting down and a loss of supply to the I&C customer, or the network, potentially affecting typically up to 6,500 customers. It is for this reason that the operational risk has been rated as High.

I&C customers at risk of shut down include large commercial and industrial sites such as (i.e. hospitals, breweries and paper mills, some of which could be exposed to significant amounts of lost revenue per day of lost production). Failure of the regulator could also result in a gas escape, which poses a risk to property and human health and safety.

1.5. Options Considered

AGN has identified the following options to address the safety and integrity related risks in section 1.4:

- Option 1: Do nothing, which will mean continuing to maintain existing Fisher 298 with increasingly expensive and difficult to source spare parts.
- Option 2: Replace Fisher 298 at 51 locations over 5 years with the Fisher EZR (accelerated program).
- Option 3: Replace Fisher 298 at 51 locations over 10 years with the Fisher EZR (as per the current 10 year preventative maintenance schedule).

1.5.1. Option 1 – Do Nothing

Under the do nothing option, the existing Fisher 298 regulators would continue to be maintained using replacement parts, which as noted in section 1.3 are becoming increasingly difficult and expensive to source, with the supplier indicating that:

- the cost of spares parts is comparable to the cost of replacing the regulator with an alternative regulator; and
- the cost of spare parts for alternative regulators is approximately 30% of the cost of the spare parts for the Fisher 298 (approximately $5 ($000, real 2016) per site versus $16 ($000, real 2016) per site).

1.5.1.1. Cost/Benefit Analysis

The only benefit of this option is that no additional capital expenditure is necessary. The option is not costless, however, because:

- The on-going cost of maintaining the regulators (estimated to be $92 ($000, real 2016) per annum) will increase as a result of the higher cost spare parts.
- If AGN is unable to procure spare parts in the time they are required then it may have to carry out a more expensive replacement with an alternative unit. This option would be more expensive than a planned replacement because purchases would be made on an ad hoc basis rather than on a bulk discounted basis. It may also result in a prolonged loss of supply while a replacement unit is procured, if there is a protracted lead time.
- The residual risk associated with this option is therefore still considered High (see Appendix A).

1.5.2. Option 2 – Replacement of the Fisher 298 Units over 5 years

This option involves the replacement of the 51 Fisher 298 regulator units with a new, modern and currently available alternative (the Fisher EZR) in the next AA period. Replacing the regulators in the next AA period will involve an accelerated replacement relative to the existing 10-year refurbishment program.

1.5.2.1. Cost/Benefit Analysis

Benefits

This option has the benefit that security and reliability of supply will be maintained through the installation of modern regulator units with readily available spare parts. The risk of supply outages, gas escapes and associated risk to property and human health and safety will therefore be reduced under this option from High to Moderate (see Appendix A). Relative to Option 3, the reduction in risk will occur over a shorter time period, allowing increased confidence in the safety and integrity of providing distribution services.

Costs

The costs of replacing the Fisher 298 with a Fisher EZR regulator over the next AA period are set out in Table 1.4 (further detail of this cost estimate is shown in Appendix B). The cost of this option are higher than Option 3 because the program involves an accelerated replacement. Additionally, whilst it normally takes two days for the normal maintenance overhaul, one additional day is required to install the replacement regulator. Additional resources will therefore be required relative to the normal maintenance schedule. It is proposed that these will be contract resources.

Table 1.4: Summary of Option 2 Costs ($000, 2016)

Item	Cost
51 Sites	
Materials	1,202
Labour	164
Disbursements (e.g. accommodation)	25
Project Management	16
Total	**1,407**

Table i.4 - See Supporting Information 2 for material quotation

1.5.3. Option 3 – Replacement of the Fisher 298 Units over 10 years

This option involves replacing the existing Fisher 298 regulator unit with a Fisher EZR regulator at the 51 sites over a 10-year period (i.e. over the next two AA periods). In contrast to Option 2, the replacement will occur in line with the normal 10-year refurbishment program, which will enable efficient use of existing resources.

Under this option, approximately 26 sites will be replaced in the next AA period in line with their current refurbishment schedule, and 25 in the following AA period.

1.5.3.1. Cost/Benefit Analysis

Benefits

This option has the benefit that security and reliability of supply is maintained due to the installation of modern regulator units with readily available spare parts. The risks are reduced to Moderate by the use of equipment that has readily available spare parts, and the existing maintenance schedule is utilised thus minimising the requirement for additional resources (refer below). Spreading the program over two AA periods will also contribute to a lower cost and deferral of capital requirements.

The risk of an extended program is offset by the ability to use the spare parts from the units that are replaced in the first period as parts for the ones to be replaced in the subsequent period, further reducing the cost by not having to purchase new parts.

Costs

The costs of this option are set out in Table 1.5 (see Appendix B for more detail). The key difference between this estimate and the estimate set out in Table 1.4 is that the replacement will be scheduled in line with the normal preventative maintenance schedule, so the use of internal resources can be maximised. Whilst one additional day is required to install the replacement regulator (refer 1.5.2.1 above), because the normal maintenance schedule is being used, the use of contractor labour is lower.

Table 1.5 Summary of Option 3 Costs ($000, 2016)

Option	Benefits	Costs
Number of sites	26	
Materials		613
Labour	(Incremental labour, additional to Option 1)	54
Disbursements (eg Accommodation)		13
Project Management		5
Total over AA period	21	685
Total over 10 years	51	1,343

1.6. Summary of Cost/Benefit Analysis

A summary of the costs and benefits of the three options is shown in Table 1.6 below.

Table 1.6: Summary of Cost/Benefit Analysis ($000, 2016)

Option	Benefits	Costs/Risks
Option 1 – Do nothing	No upfront capex required	This option will result in higher costs over the longer-term because the cost of replacement parts (where they are available) are over three times the cost of the parts for alternative regulators and comparable to the cost of purchasing a new regulator. The greatest risk with this option is that the inability to get spares may cause a loss of supply to an I&C customer or potentially a network outage for an extended time period, while a replacement unit is procured, with a protracted lead time. On-going annual opex cost of $91.7 ($000 real 2016)

Option 2 – Replacement of Fisher 298 units at 51 locations over 5 years	Security and reliability of supply is maintained due to the installation of modern regulator units with readily available spare parts. Residual risk reduced to Moderate. Lower cost of spare parts in the future.	$1,407 ($000, real 2016) over the five years of the next AA period. The cost is higher than Option 3 due to the additional use of contactors for the increased workload of completing the program in 5 years instead of 10.
Option 3 – Replacement of Fisher 298 units at 51 locations over 10 years	Security and reliability of supply is maintained due to the installation of modern regulator units with readily available spare parts Residual risk reduced to Moderate. Lower cost of spare parts in the future.	$1,343 ($000, real 2016) over ten years ($685 ($000) over the five years of the next AA period and $658 ($000) in the following AA period).

A cost-benefit analysis has been undertaken to quantitatively determine the least cost option. The result of this analysis is shown in Table 1.7 below, which compares the net present value of the costs and benefits associated with each of the options outlined above, i.e.:

- Option 1: Do Nothing;
- Option 2: Institute a replacement programme over the five years of the next AA period; and
- Option 3: Institute a replacement programme over the ten years of the next and following AA periods.

Table 1.7: Comparison of the Options ($000, 2016)

				Next AA Period			Subsequent AA Periods	
Item	**NPV**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023-2042**	**Total**
Option 1	-1,573	-92	-92	-92	-92	-92	-1,835	**2,294**
Option 2	-287	-183	-166	-166	-166	-166	+841	**-5**
Option 3	-178	-92	-77	-77	-77	-77	+458	**+59**
Discount Rate (real pre-tax WACC)	**3.14%**							

Notes: Please see Supporting Information 1 for NPV calculations

As this table shows, Option 3 is most cost effective of the three options over an analysis period of 25 years.[2] When coupled with the fact that there is not a significant difference between the residual risk under options 2 and 3, Option 3 is preferable to Option 2.

[2] An analysis period of 25 years has been chosen to model the benefits of the spare parts savings to be accounted for over 2 x 10 year overhaul periods.

1.7. Proposed Solution

1.7.1. What is the Proposed Solution?

The proposed solution is Option 3, which will involve the replacement of Fisher 298 regulators with Fisher EZR regulators, at 51 locations over the next two AA periods. Regulators at 26 locations are proposed for replacement in the next AA period, and the associated costs are set out in section 1.7.3 below.

1.7.2. Why are we Proposing this Solution?

Option 3 is being proposed because it is the most cost effective way to maintain the safety and integrity of services and ensure security of supply to I&C customers and domestic customers on networks that are supplied via district regulators. It will also:

- result in lower costs over the longer term because parts are readily available and lower cost than the parts required for the Fisher 298;
- maximise the life of the existing regulators;
- enable the majority of the work to be carried out by internal resources, which reduces the labour cost component of the program (i.e. because the replacement is aligned with the existing 10-year overhaul schedule);
- limit disruption to other work, because the program can be delivered within the existing 10-year overhaul schedule; and
- reduce the residual risks associated with the Fisher 298 regulators from High to Moderate.

Additionally, the adoption of a slower long term program allows management the ability of developing and putting in place long term programs in others areas to increase operational efficiencies. A 5 year program will require increased management resources and result in reduced focus on developing other improvements to operational efficiency, with the possible result of more reactive responses in other areas of work, with resultant increased costs.

Further, given the nature of this project, AGN considers it to be consistent with the findings from our stakeholder engagement program in which customers indicated that they are supportive of initiatives that maintain the reliability and safety of the network.

1.7.3. Forecast Cost Breakdown

The cost of the proposed replacements is shown in Table 1.8 below (see Appendix B for further detail). The estimated costs are based on the following:

- Materials: The cost of the Fisher EZR is based on quotations obtained from the suppliers of these regulators (see Supporting Information 2).
- Labour: The majority of the labour will be carried out by APA although contract labour will be required to support the requirement of 1 additional day for regulator replacement. The labour rates are based on the following:
    - standard internal labour rates for the APA Group for direct labour and project management and administration; and
    - standard rates for the contract labour, which are based on the rates established through a competitive tender process.

- Disbursements: Provision has also been made for travel and accommodation for sites located outside of the metropolitan area.

As noted above the proposed replacements are planned to be undertaken as part of the routine 10 yearly maintenance schedule of the applicable sites, with approximately five units to be replaced each year (with the exception of 2018 when six units will be replaced). As a site comes up for its 10 yearly overhaul, the new regulator will be installed in place of the existing one. The replacement regulators have also been selected so that they can simply replace the existing regulator, with no pipework or other modifications necessary. The existing maintenance schedule can therefore be maintained and the use of existing personnel maximised.

Table 1.8: Project Cost Estimate in AA Period ($000, 2016)

	2018	2019	2020	2021	2022	Total
Volume	6	5	5	5	5	26
Unit Cost	26.3	26.3	26.3	26.3	26.3	26.3
Total	**158**	**132**	**132**	**132**	**132**	**685**

* Totals may not add due to rounding

1.7.4. Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN considers the forecast capex for this project to be:

- *Prudent* – AGN has examined a number of options to address the issue of aging regulators for which spare parts are becoming increasingly costly and difficult to obtain. It has reviewed the costs and risks associated with each option and selected the least cost option, and one that can be delivered within the existing routine maintenance schedule, representing minimum disruption to delivery of network services. For this reason the expenditure can be regarded as prudent.
- *Efficient* –There is not a significant reduction in risk for a 5-year program as against a 10-year program, and so an accelerated process is not proposed. The proposed expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur. The manner in which AGN intends the replacement to be carried out (i.e. utilising the established routine maintenance schedule to undertake the replacements and utilising existing operational personnel), can also be considered efficient.
- *Consistent with accepted good industry practice* – It is incumbent on operators of distribution networks to ensure that installed assets are operated and maintained in accordance with our safety and operating plan (Australian Standard AS4645[3]). Reducing the risk associated with these regulator units to as low as reasonably practicable in a manner that balances cost and risk is also consistent with Australian Standard AS4645 and therefore in keeping with accepted and good industry practice.
- *Achieves the lowest sustainable cost of delivering pipeline services* – Carrying out the replacement program over the next two AA periods is the most cost effective option, because it allows the existing maintenance program and existing operational labour to be used to carry

[3] AS 4645.1 2008, Section 2.4

out the work. Replacing the Fisher 298 with the Fisher EZR will also result in lower costs over the longer term because the cost of on-going spares are only 30% of those of the Fisher 298.

The capex can therefore be viewed as being consistent with rule 79(1)(a) of the NGR. The proposed capex is also consistent with rule 79(1)(b), because it is necessary to:

- *maintain and improve the safety of services (rule 79(2)(c)(i))* – Replacing the Fisher 298 regulators will ameliorate the risk of an unplanned leak on aging equipment and therefore improve the safety of services.
- *maintain the integrity of services (rule 79(2)(c)(ii))* – Replacing the Fisher 298 regulators on a proactive basis rather than a reactive basis will ameliorate the risk of a prolonged supply interruption (i.e. due to the inability to obtain parts readily) and therefore maintain the integrity of services.
- *maintain the service provider's capacity to meet existing levels of demand for services existing at the time the capex is incurred (rule 79(2)(c)(iv))* – The Fisher 298 regulators are currently used to meet existing demand at field regulator sites and I&C customer sites, so if a regulator was to fail then it would adversely affect AGN's ability to meet existing levels of demand.

Appendix A Risk Assessment

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Option Risk
Risk Untreated	Likelihood	*Possible*	*Occasional*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*High*
	Consequence	*Medium*	*Minor*	*Significant*	*Medium*	*Medium*	*Medium*	*Medium*	
	Risk Level	*Moderate*	*Low*	*High*	*Moderate*	*Moderate*	*Moderate*	*Moderate*	
Residual Risk Option 1	Likelihood	*Possible*	*Occasional*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*High*
	Consequence	*Medium*	*Minor*	*Significant*	*Medium*	*Medium*	*Medium*	*Medium*	
	Risk Level	*Moderate*	*Low*	*High*	*Moderate*	*Moderate*	*Moderate*	*Moderate*	
Residual Risk Option 2	Likelihood	*Unlikely*	*Possible*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Moderate*
	Consequence	*Medium*	*Minor*	*Medium*	*Minor*	*Minor*	*Medium*	*Minor*	
	Risk Level	*Moderate*	*Low*	*Moderate*	*Low*	*Low*	*Moderate*	*Low*	
Residual Risk Option 3	Likelihood	*Unlikely*	*Possible*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Moderate*
	Consequence	*Medium*	*Minor*	*Medium*	*Minor*	*Minor*	*Medium*	*Minor*	
	Risk Level	*Moderate*	*Low*	*Moderate*	*Low*	*Low*	*Moderate*	*Low*	

Appendix B Detailed Cost Estimates

This appendix presents the detailed cost estimates for Options 1 to 3.

Option 1 – Do Nothing

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Option 2 – Replacement of Fisher 298 Regulators over 5 years

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The assumptions used to derive this estimate are as follows:

- 51 sites are completed over 5 years, at an approximate average of 10 per year.
- Each site requires 3 days labour for 3 people, as opposed to 2 days labour for 2 people for normal maintenance. That is, incremental labour is 1 day for 2 people.
- The work will be performed by a combination of internal and contract labour. It is assumed that internal labour will perform 17 sites and contract labour 34 sites.
- Hourly rates for internal labour are based on current APA labour rates, and for contractors on current (March 2016) contract rates for AGN’s major operations sub-contractors (Comdain).

Option 3 – Replacement of Fisher 298 Regulators over 10 years

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The assumptions used to derive this estimate are as follows:

- 51 sites are completed over 10 years, 26 in the next AA period (approximately 5 per year), and 25 in the following AA period (5 per year).
- Each site requires 3 days labour for 3 people, as opposed to 2 days labour for 2 people for normal maintenance. That is, incremental labour is 1 day for 2 people.
- The work will be performed by a combination of internal and contract labour. It is assumed that internal labour will perform 34 sites and contract labour only 17 sites.
- Hourly rates for internal labour are based on current APA labour rates, and for contractors on current (March 2016) contract rates for AGN's major operations sub-contractors (Comdain).

This approach will leave 25 sites to be completed in the following AA period (2023-27), at an estimated cost of approximately $658 ($000, real 2016) over the term of the AA period.

Business Case – Capex V37

Water Bath Heater Coil Replacement

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	Jarrod Dunn, *Manager Systems Operations*
Approved By	Andrew Foley, *General Manager Victorian Networks*

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	Water Bath Heaters (WBH) are key pieces of equipment that ensure the correct functioning of a city gate. A WBH contain coils that are immersed within a water bath. The bath is heated by gas burners to heat the gas flowing through the coils prior to pressure reduction, to guard against brittle fracture of downstream pipework due to temperature loss on pressure reduction WBH coils have an expected life of up to 25 years when the WBH is properly maintained. AGN monitors the condition of WBH coils through routine inspections. When a WBH fails an inspection, it is deemed to be at the end of its useful life (i.e. it is no longer fit for purpose), and must be replaced relatively quickly, to ensure the safety and integrity of services are maintained and that Australian Gas Networks (AGN) can continue to meet existing levels of demand. If this does not occur, and the WBH coil corrodes it may result in a gas leaks, which may, in turn, result in a fire and/or explosion and/or loss of or restriction of supply to the 10,000-30,000 customers supplied by a city gate. The consequences of not replacing the WBH coils can therefore be significant Based on prior experience, approximately 3 WBH coils fail the inspection and need to be replaced within a five year period. A successful solution to this issue will ensure that city gates operate as designed, and continue to supply gas on a normal basis into AGN's Victorian networks.
Options Considered	The following options have been considered: 1 Option 1: Do nothing. 2 Option 2: Replace WBH coils when they fail testing and are deemed to be at the end of their useful lives. Another potential option is to bypass the heater and operate the city gate without gas heating, but this is not considered a feasible option because without heating the gas will cool down to a level where the pipework will be at risk of breakage, which will give rise to the risk of leakage, a fire or explosion or regulator failure.

Proposed Solution	Option 2 has been selected because it is the only feasible solution that maintains the integrity and functioning of WBHs within design specification.
Estimated Cost	The forecast capital expenditure for option 2 is $192 ($000, real 2016) over the next AA period.
Consistency with the National Gas Rules (NGR)	The replacement of WBH coils that are no longer fit for purpose complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because: • 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)); and • it is justified under rule 79(2)(c) as it is required to: o maintain and improve the safety of services (79(2)(c)(i)); o maintain the integrity of services (79(2)(c)(ii)); and maintain the capacity to meet existing levels of demand (79(2)(c)(iv)).
Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Reliability and Safety themes as its implementation will allow AGN to maintain the safety of the network whilst continuing to provide a highly reliable supply of natural gas to customers by ensuring that equipment which has reached the end of its useful life is replaced with equipment that is fit for purpose. More information detailing the results of the stakeholder engagement program is provided in Chapter 3 of our Access Arrangement Information document.

1.3. Background

There are 43 water bath heaters (WBH) installed at city gates within AGN's Victorian network. The function of a WBH is to heat the gas flowing through the city gate prior to it being reduced in pressure, to ensure that the temperature loss on pressure reduction (Joule-Thompson effect) does not fall below the minimums specified for pipework and other equipment before integrity is compromised.

A WBH is a vessel containing a "bath" of water, which is heated by gas burners to the required temperatures. The process gas being heated flows through a "coil", being loops of steel pipework, which is immersed in this water, and gains its heat through the heat transfer from the water, through the coil into the gas. The coil, being constantly immersed in the water, is subject to a highly corrosive environment, and so corrosion inhibitor is added to the water to combat corrosion of the pipework.

AGN's routine maintenance program involves a 5 yearly inspection regime of WBH coils during periods of low demand, whereby the heater is shut down, the water drained and the coil removed and subject to a rigorous corrosion inspection and assessment. This inspection determines the future expected life of the coil, and if it is found to be fit for ongoing service, it is hydrostatically tested and reinstalled into the WBH. AGN is planning to inspect approximately 43 WBH heater coils in the next Access Arrangement (AA) Period, at an average of 8-9 per year. Table 1.3 shows the number inspected in the past years.

Table 1.3: WBH Coil Inspections

Year	Number Inspected
2012/13	8
2013/14	8
2014/15	8
2015/16	8
2016/17 (Planned)	8
Average per year	**8**

Where a WBH heater coil fails the inspection, it has reached the end of its usable life and needs to be replaced with a new one. Of the average 40 coils inspected each 5 yearly period, typically 3 need to be replaced across the 5 years.

Figure 1.1: Typical Corrosion of Coils Resulting in End-of-Life Assessment

The typical service life of a WBH coil is approximately 25 years, when maintained in accordance with the preventative maintenance schedule. When a coil is assessed as having reached the end of its life, its dimensions are verified, it is replaced into the WBH, and a new coil ordered from the supplier. Once the new coil is received (typically within 2-3 months), the heater is taken out of service and the new coil fitted in place of the old one.

An equivalent project was approved by the AER in the last AA review[1] under V96 Field Assets Alterations and Replacements. This business case (V96) was a high level business case canvassing a broad, but unspecified, range of work within the network system that is necessary to ensure assets operate reliably, and asset integrity and continuity of supply to customers is maintained, one element of which was the replacement of WBH coils. The AER approved a $6.6 million allowance for all of the work specified in Business Case V96 for the current AA period, which was based on historical expenditure for this type of work.

1 AER - Access arrangement final decision - Envestra - Part 2 - March 2013, Table 4.28

1.4. Risk Assessment

A risk assessment has been carried out using APA's established evaluation criteria (detailed in Appendix A – Risk Assessment) to produce an estimated level of risk, the results of which are summarised in the table below.

Table 1.4: Risk Rating

Risk Area	Untreated Risk Level
Health and Safety	Moderate
Environment	Low
Operational	High
Customers	Moderate
Reputation	Moderate
Compliance	High
Financial	High
Untreated Risk Rating	**High**

As this table highlights, the untreated risk associated with WBH coils that are no longer fit for purpose is High. The principal risk with such WBH coils is that they may fail unexpectedly, which could result in a gas escape through the shell of the heater, with the potential for ignition, fire and/or explosion, which creates a safety risk to the local public and potential for damage to property.

The WBH is an expensive item on a city gate site, and usually the design of the city gate is such that there is only one WBH provided at each city gate. In the event of a failure or a leak from the WBH, the outlet temperature of the gas will quickly fall below levels, which may result in embrittlement of pipework and subsequent failure.

If the WBH is compromised in this manner, the whole city gate will be required to be shut down and supply will cease to the network area. This will result in a loss of or restriction to supply to the network, potentially affecting typically between 10,000 and 30,000 customers. The most likely scenario for most city gates is a restriction to supply, as in the interconnected parts of the network other city gates can maintain a lower level of supply, but in some cases where only one city gate supplies the network (eg regional towns) complete loss of supply would result. It is for this reason that the operational risk is rated as High.

If there is a loss of supply at a city gate then the cost to re-light even 20,000 consumers would be in the vicinity of $800 ($000, real 2016) in the metropolitan area. In addition, if there was an extended outage Guaranteed Service Level (GSL) payments of up to $300 per customer[2] would also be payable to customers whose gas supply is interrupted. It is for this reason that the financial risk is rated as High.

[2] Gas Distribution System Code, V 11, Part E

The High risk rating for the Compliance category is driven by a consequence of Significant under the APA Risk Matrix, due to the probable investigation that would be undertaken by Energy Safe Victoria for a leak or larger failure at a city gate.

1.5. Options Considered

AGN has identified the following options to address the risks outlined in section 1.4:

- Option 1: Do nothing.
- Option 2: Replace WBH coils that have reached the end of their usable lives, typically 3 in a 5 year period.

Another potential option is to bypass the heater and continue to operate the city gate without gas heating. However, this is not considered a feasible option because without heating, the gas will cool down due to the Joule Thompson effect of the reduction in pressure, which is one of the main functions of a city gate, and quickly reach temperatures where the pipework becomes brittle and extended operation at these temperatures will result in pipework breakage and subsequent leakage, fire or explosion or regulator failure as a result of freezing the internals resulting in the site shutting down. This option has not therefore been considered any further.

1.5.1. Option 1 – Do Nothing

Under the Do Nothing option, coils will not be replaced when they are found to fail.

1.5.1.1. Cost/Benefit Analysis

The only benefit of this option is that it does not require any upfront capital expenditure. The costs, however, could be significant because as outlined above, the corrosive environment of immersion in water, will result in the virtual certainty of a corrosion hole in the pipe wall, and consequent leak inside the WBH. This leak will result in:

- A gas escape through the access hatch of the WBH, with the high potential for ignition and fire or explosion, given that the operating gas burners of the heater itself are in close proximity to the access hatch.
- The city gate pipework losing pressure resulting in the primary and secondary regulators operating as designed, and gas supply to the outlet of the station ceasing. This would represent a loss of supply to the downstream networks, and could potentially affect, depending on the location of the city gate, up to 30,000 customers. As outlined in section 1.4, the cost of reinstating supply if this was to occur would be significant. For example, the cost to re-light even 20,000 consumers would be in the vicinity of $800 ($000, real 2016) in a metropolitan area and GSL payments of up to $300 per customer[3] would also be payable to customers whose gas supply is interrupted.

The residual risk associated with this option is therefore High, which is why this option is not considered a feasible option.

[3] Gas Distribution System Code, V 11, Part E

1.5.2. Option 2 – Replace WBH coils that have reached the end of their usable lives

This option would see those WBH coils that do not pass the routine maintenance inspection replaced with new coils. This is typically 3 in the 5 years of the AA period, based on the historical average of those replaced over the last 5 years.

1.5.2.1. Cost/Benefit Analysis

This option will enable the WBHs to continue functioning as designed. Replacing an end-of-life coil will remove the risk of a degraded coil failing during operation (sustaining a corrosion hole which results in a gas leak), with the potential for fire and/or explosion, injury to operational personnel or the public and/or the loss of or restriction in supply to a large segment of the networks that could result in significant rectification costs (see section 1.4). The residual risks under this option will therefore fall from High to Moderate (see Appendix A).

The cost of this option, based on 3 coil replacements in the 5 year AA period, is estimated to be $192 ($000, real 2016), or $64 ($000) per coil (see section 1.7.3 for more detail), which is far lower than the costs that would be incurred under Option 1 (i.e. $64 ($000) per coil versus over $800 ($000) if there is a single outage at city gate supplying 20,000 customers).

1.6. Summary of Cost/Benefit Analysis

A summary of the costs and benefits of the two options is shown in Table 1.5 below.

Table 1.5: Summary of Cost/Benefit Analysis

Option	Benefits	Costs/Risks
Option 1	No upfront capital expenditure	Normal maintenance expenditure would continue. This option has the high risk of the coil corroding inside the heater to the point where a hole or holes form in the coil piping, resulting in leaks externally from the heater, with consequent fire or explosion. Potential loss of supply to downstream networks, up to 30,000 customers affected. Cost to relight 20,000 customers is $800 ($000) GSL payments of up to $300 / customer if there is an extended outage Risk of incorrect functioning of the heater, resulting in out of specification gas impacting downstream pipework. Residual risk High.
Option 2	• Continued maintenance of the heater coils within specification. • Maintain city gate pipework and equipment within correct temperature specification. • Avoids the risk of heater malfunction and gas leak due to coil failure. • Avoids the relighting costs that would be incurred if the failure caused an outage and also avoids GSL payments if there is an extended outage.	$192 ($000) for 3 coil replacements over the term of the AA period.

Residual risk Moderate.

1.7. Proposed Solution

1.7.1. What is the Proposed Solution?

Option 2 has been selected as the preferred option, which will involve replacing WBH coils when they fail inspections and are deemed to no longer be fit for purpose.

1.7.2. Why are we Proposing this Solution?

Option 2 is the only feasible solution that avoids continued degradation of the WBH coils and maintains their integrity and functioning within design specification. The coils, as properly maintained by AGN, have an expected life of up to 25 years, but being part of a continuous process stream (gas flows through them constantly as part of the supply route through a city gate), and constantly in the highly corrosive environment of the water bath, when they reach the point of being assessed as at the end of their lives, they must be replaced.

To not replace them and either continue to operate with the coil in situ, or by bypassing the heater, exposes AGN and the pubic to further risks of the nature outlined above. These risks have been given a High risk rating.

Additionally, given the nature of this project, AGN considers it to be consistent with the findings from the stakeholder engagement program in which customers indicated that they value the current standard of reliability and are supportive of initiatives that maintain the reliability and safety of the network.

1.7.3. Forecast Cost Breakdown

A summary of the cost estimate for this Option 2 is shown in Table 1.5 below. The cost estimate is based on:

- historical costs for past supply of WBH replacement coils from our supplier, which have been secured through competitive procurement processes;
- the typical length of time it takes to take the heater off line, drain the water, remove and replace the coil and re-commission the heater of 3 days; and
- current APA internal labour rates for gas fitters, supervisors and engineers.

Provision has also been made for travel costs at regional sites.

A more detailed estimate for a typical coil replacement is shown in Appendix B.

Table 1.6: Project Cost Estimate ($000, $2016)

	2018	2019	2020	2021	2022	Total
Number of Sites	1	-	1	-	1	3
Direct Labour	6	-	6	-	6	18.9
Materials	54	-	54	-	54	160.5
Project Management & Accommodation	4	-	4	-	4	12
Total	**64**	**-**	**64**	**-**	**64**	**192**

Note: Figures may not add due to rounding

1.7.4. Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN considers the forecast capex for this project to be:

- *Prudent* – The expenditure is necessary to ensure that the ongoing integrity of the water bath heaters at city gates is maintained and there are no major gas escapes or loss of supply incidents that could impact public safety and reliability of supply. The expenditure is also of a nature that a prudent service provider would incur.
- *Efficient* – The project cost estimate is based on the actual historical costs of replacement coils that have been procured through competitive procurement processes, current APA labour rates and the average length of time it takes to replace a WBH coil. The forecast costs can therefore be viewed as efficient.
- *Consistent with accepted good industry practice* – The identification and rectification of WBH integrity issues as outlined above and the reduction of risk to as low as reasonably practicable in a manner that balances cost and risk is consistent with Australian Standard AS2885 and therefore in keeping with accepted and good industry practice.
- *Achieves the lowest sustainable cost of delivering pipeline services* – Continuing to ensure correct as-designed functioning of a key piece of equipment at city gates, WBH, is consistent with ensuring gas continues to be within specification (temperature), and avoids more costly pipework and/ or gas supply failures, which are vastly more expensive than coil replacement. Replacing the coils is also a lower cost option than the do nothing option and will therefore result in a lower cost of service delivery over the longer term.

The capex can therefore be viewed as being consistent with rule 79(1)(a) of the NGR.

The proposed capex is also consistent with rule 79(1)(b), because the expenditure is necessary to:

- maintain and improve the safety of services (rule 79(2)(c)(i)) - the replacement of end of life WBH coils will result in a reduced likelihood of a coil failure which could lead to a gas fire/explosion;
- maintain the integrity of services (rule 79(2)(c)(ii)) - the replacement of end of life WBH coils will result in a reduced likelihood of large scale supply loss; and

maintain the service provider’s capacity to meet existing levels of demand for services existing at the time the capex is incurred (rule 79(2)(c)(iv)) – the replacement of end of life WBH coils will result in maintaining the current reliability of supply to existing customers.

Appendix A Risk Assessment

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Option Risk
Risk Untreated = Option 1	**Likelihood**	*Possible*	*Occasional*	*Occasional*	*Occasional*	*Possible*	*Possible*	*Possible*	**HIGH**
	Consequence	*Medium*	*Minor*	*Major*	*Medium*	*Medium*	*Significant*	*Medium*	
	Risk Level	*Moderate*	*Low*	*High*	*Moderate*	*Moderate*	*High*	*Moderate*	
Residual Risk Option 2	**Likelihood**	*Unlikely*	*Possible*	*Unlikely*	*Possible*	*Unlikely*	*Unlikely*	*Unlikely*	**MODERATE**
	Consequence	*Minor*	*Minor*	*Significant*	*Medium*	*Medium*	*Significant*	*Medium*	
	Risk Level	*Low*	*Low*	*Moderate*	*Moderate*	*Moderate*	*Moderate*	*Moderate*	

Appendix B Detailed Cost Estimate

The cost estimate for replacement of a WBH coil is shown below.

The replacement coil cost is based on invoices from the coil supplier for an actual coil replacement during the current AA Period.

The hourly rate for labour is sourced from current APA unit labour rates.

The 3 days allowed for the coil replacement is typical for this type of work.

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
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Business Case – Capex V38

City Gate Refurbishment

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	James Rudolph, *Field Maintenance Manager*
Approved By	Andrew Foley, *General Manager Victorian Networks*

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	Australian Gas Networks Limited (AGN) has 100 City Gate and Field Regulator stations within its Victorian and Albury (NSW) regulated networks. Of these, 51 include fenced compounds with various equipment including water bath heaters, pressure regulator kiosks or pits, and above ground pipework. Over the life of these stations, changes in ownership, industry practices, engineering and safety standards, and maintenance regimes have resulted in degradation of these assets, with many no longer meeting the current engineering and industry standards. The failure to meet current standards exposes personnel to health and safety risks, and presents an operational risk to the business given the potential loss of supply through a city gate station through failure of equipment or componentry. Recent reviews conducted by both Energy Safety Victoria and AGN have resulted in the identification of 23 sites that pose relatively high health and safety and operational risks and need to be refurbished to, amongst other things, re-level city gate compounds, remove trip hazards, upgrade vehicle protection, upgrade site security, install access ladders and upgrade signage. A successful program of works will ensure that all City Gate assets comply with the current Australian Standards (AS2885, AS1657) and the Victorian Occupational Health and Safety (OH&S) Regulations, reduce the risk of adverse events leading to loss of supply, and assist in providing a safe working environment for operational personnel.
Options Considered	The following options have been considered: 1 Option 1: Do nothing, which will involve addressing non-conformance issues with reactive capex works, continuing to address minor issues through routine maintenance activities. Where possible update sites when performing other capex works (i.e. network expansion). 2 Option 2: Refurbish 11 city gate sites over the next AA period, and 12 over the following AA period. 3 Option 3: Refurbish 23 city gate sites over the next AA period.
Proposed Solution	Option 2 is the preferred solution because it is the most cost-effective solution and reduces the risks to human health and safety to as low as reasonably practicable in a manner that balances cost and risk.

Estimated Cost	The forecast capital expenditure for this project is $706 ($000, 2016), of which $412 ($000, 2016) will be spent in the next (2018-2022) Access Arrangement (AA) period, and $294 ($000, 2016) in the subsequent (2023-2027) AA period.

Consistency with the National Gas Rules (NGR)	The refurbishment of various degraded assets at city gates complies with the new capital expenditure criteria in rule 79 of the National Gas Rules (NGR) because:
	• 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)); and
	• it is justified under 79(2)(c) as it is required to:
	  ◦ maintain and improve the safety of services (79(2)(c)(i));
	  ◦ maintain the integrity of services (79(2)(c)(ii)); and
	  ◦ comply with a regulatory obligation or commitment (79(2)(c)(iii)).

Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Safety theme as its implementation will allow AGN to maintain the safe supply of natural gas to customers by reducing the risk of an operational failure at city gate and field regulator sites. More information detailing the results of our stakeholder engagement program is provided in Chapter 5 of the Access Arrangement Information document.
Supporting Information	• V38 Supporting Information 1 (NPV and Options Analysis)

1.3. Background

AGN has 100 City Gate and Field Regulator stations within its Victorian and Albury (NSW) regulated networks. Of these, 51 include fenced compounds (referred to as city gate compounds in the following text) with various equipment including water bath heaters, pressure regulator kiosks or pits, and above ground pipework. These facilities perform the functions of custody transfer metering and pressure reduction and control, from higher pressure pipelines owned by transmission pipeline entities into the AGN Victorian distribution networks.

Over the life of these city gate assets, changes in engineering and safety standards have resulted in degradation of these assets, with many no longer meeting the current engineering and industry standards. The Gas Distribution System Code requires compliance with current Australian Standards, while the Gas Safety Act, administered by Energy Safe Victoria, states that gas companies must minimise as far as possible the hazards and risks associated with gas to the public, customers and property.

1.3.1. ESV Audit

A recent Energy Safe Victoria (ESV) audit in December 2015 of 22 city gate compounds (out of 51 in our Victorian and Albury network) identified several non-conforming features and a list of observations pertaining to these facilities.

The non-conformance issues identified by the ESV included: lack of earthing on water bath heaters, where this was not a requirement at the time of installation; valves whose operation was compromised due to reaching end of life; and slam-shut panels either not operating (one site) or operating at elevated actuation pressures, possibly due to age or changed operating conditions.

Figure 1.1: No Earthing on Heater, Rosedale City Gate

Other observations raised by ESV highlighted: lack of signage referring to AGN/APA at stations; potential trip hazards and a range of safety improvements required under new standards.

1.3.2. 5 Yearly Station Integrity Review

In addition to ESV's audit results, AGN conducts 5 yearly in depth station integrity reviews of all City Gate and Field Regulator asset, with the most recent reviews completed in 2014-2015. Similar action items were identified by this process, including: removal of potential trip hazards in city gates; installing and painting bollards for impact protection and extending slabs around pits for safe entry to confined spaces.

Figure 2: WBH Slab Edge Exposed – Trip Hazard

1.3.3. Summary of Identified Issues

The issues identified above by the ESV and AGN can be categorised into those which generate operational risks and those that generate health, safety and environment (HSE) risks. Operational risks may give rise to poor pressure control, loss of supply due to equipment failure or vandalism, and damage to equipment due to vehicle impact. HSE risks may result in injuries to personnel from: slips, trips and falls at ground level; falls from a height; vehicle impact with personnel; manual handling; exposure to natural gas; and fire.

Of the 51 City Gate and Field Regulator sites with compounds, 49 were identified as having multiple issues which require rectification. A risk assessment of the identified issues was performed, and the 20 highest risk sites were constructed prior to 1995, while a further three were built in 1998. These 23 highest risk sites present both HSE and operational risks, while the remaining 26 sites largely have HSE risks of Moderate or lower ranking. The remaining two sites have been recently completed and require no immediate work.

These issues have developed over a number of years and are not typically within the scope of planned maintenance activities. Previous rectification activities have been conducted in an ad-hoc manner and consist of reactive works aimed at remediating immediate problems and high risk locations at the time these are identified. Examples include: relevelling, new bollards, and replacement of the security fence at the Wodonga City Gate compound, completed in 2014 (total cost $79,000); and works at the Benalla City Gate, completed in 2016, where isolated trip hazards within the compound have been eliminated and bollards have been painted to improve visibility ($3,100).

Table 1.3 below provides a summary of both the operational and HSE risks that have been identified, while Appendix C contains a list of the high risk sites.

Table 1.3: Summary of Issues

Operational	Health, Safety, Environment
Vehicle impact prevention bollards not present of do not meet current standards resulting in damage to equipment	Vehicle impact prevention bollards not present of do not meet current standards resulting in risk to personnel.
Degraded compound fencing requiring repair to address security risks	Trip hazards due to protruding equipment/slab edges
Site signage out of date	Trip hazards due to uneven surface within compound
Site drawings out of date	Secondary emergency exit gates not present or without single push exit bars
Pressure control equipment inoperable or operating at incorrect settings	Water bath heater access platforms unsafe or not provided

1.3.4. Impact and compliance issues

As indicated in Section 1.3.3, issues affecting the safety of personnel are addressed through operational maintenance activities, and major upgrades have been conducted in the past coinciding with other capital work at city gates. However, the volume of issues identified has resulted in the need for a planned program of capital works specifically focused on addressing these issues.

The issues identified present potential risks to AGN personnel performing maintenance activities within these city gate stations and may mean that AGN does not comply with its obligations under the Victorian *Occupational Health and Safety Act 2004* to provide and maintain a safe work place. Further, if some of the identified items are not addressed, the security of supply to domestic gas users may be affected.

The impacts of this problem are two-fold:

- HSE impacts such as minor medical treatment injuries, through to more serious injuries that result in lost time to injury (LTI), and in the most extreme cases serious consequences including disability or death.
- Operational impacts such as loss of supply to consumers due to vehicle impact, loss of supply or damage to downstream equipment due to slam-shut operation failure; and loss of supply due to vandalism or incorrect operation of valves.

In addition to the risks above, there is a compliance risk if stations are found to not comply with the current applicable Australian Standards. As identified above, a recent ESV audit of City Gate stations found several non-conformances with current standards, including:

- AS2885.1 Section 6.2.4.6, which establishes the requirements for station security, including two metre high fences, and a requirement for at least two exits to provide escape routes;
- AS 2885.1 Section 6.2.1 (e) and Appendix C2.1 (h) require that sites be designed to protect from external interference by vehicle impact;
- Access ladders to water bath heaters not complying with AS1657. Clause 1.1 of AS1657 outlines the scope to which this standard applies, and includes inspection ladders and access ways; and
- Trip hazards in city gate compounds not meeting duties under the Victorian Occupational Health and Safety Regulations 2007.

Schedule 3 of the Gas Distribution Rules sets out the Australian Standards applicable to gas distribution licensees, and defines Australian Standards as "the most recent edition of a standard publication by Standards Australia". Further, the Gas Safety Act specifically charges ESV with issuing minimum safety standards for gas related services, and with monitoring compliance of companies providing such services. The Gas Safety Act[1] also defines the general duties of gas companies as follows:

32 General duties of gas companies

A gas company must manage and operate each of its facilities to minimise as far as practicable:

1. the hazards and risks to the safety of the public and customers arising from gas; and
2. the hazards and risks of damage to property of the public and customers arising from gas; and
3. the hazards and risks to the safety of the public and customers arising from:
   a. interruptions to the conveyance or supply of gas; and
   b. the reinstatement of an interrupted gas supply.

Addressing the issues outlined above is therefore required to ensure that the AGN networks comply with the current Australian Standards, satisfy the requirements of the Gas Safety Act and

1 Gas Safety Act 1997 (Vic) section 32

Gas Distribution System Code[2], provide a safe working environment for operational personnel and to reduce the risk of adverse events leading to loss of supply.

1.4. Risk Assessment

A risk assessment has been performed on the risks associated with the identified issues, and is summarised in Table 1.4 below. The full risk assessment result is set out in Appendix A.

Table 1.4: Risk Rating

Risk Area	Untreated Risk Level
Health and Safety	High
Environment	Low
Operational	High
Customers	Low
Reputation	Moderate
Compliance	Moderate
Financial	Moderate
Untreated Risk Rating	**High**

As outlined in the table above, the untreated Health and Safety, and Operational risks were assessed as High.

Health and safety threats where sites do not meet the current industry standard for site vehicle protection include injury to personnel due to impact of a vehicle with the site. Further, uneven surfaces within city gate compounds pose a trip hazard, as do exposed slab edges. Uneven surfaces also pose a manual handling risk, especially where heavy equipment must be wheeled or rolled across compounds. At many City Gate sites AGN operates water bath heaters. In order to ensure proper operation, the water level in this equipment must be maintained. Water is added through a filling point located on top of the heater vessel, and this must be accessed using a ladder or access platform. At many sites the existing equipment is inadequate or does not meet the Australian Standard for access ladders and platforms, exposing personnel to a fall risk.

Similar operational threats exist, with lack of impact protection and ineffective site security specific examples of shortcomings in older stations. Where features are not at the current standard, for example vehicle impact bollard, the potential exists for pipework failure due to vehicle impact on a site, either due to a vehicle entering the site in an uncontrolled manner, or because of mobile plant and vehicle operating in proximity to unprotected or poorly protected pipework. Where security is insufficient theft of equipment (for example fire extinguishers) has occurred, posing a risk to personnel and the site. Vandalism of pipework, or unauthorised operation of valves, is also a risk where security is poor. Finally, if flow diagrams and site drawings are not current, there is potential for operators to operate incorrect valves, causing a loss of supply.

[2] Gas Distribution System Code v11

1.5. Options Considered

AGN has identified the following options to rectify the issues identified in section 1.3 and address the associated risks outlined in section 1.4, including:

- Option 1: Do nothing, which will involve addressing non-conformance issues with reactive capex works, continuing to address minor issues through routine maintenance activities. Where possible update sites when performing other capex works (i.e. network expansion).
- Option 2: Refurbish 11 city gate sites over the next AA period, and 12 over the following AA period.
- Option 3: Refurbish 23 city gate sites over the next AA period.

1.5.1. Option 1 – Do Nothing

Under the do nothing option, no major refurbishment of city gate stations would be conducted. Where HSE and non-conformance issues are identified, they would be addressed in an ad-hoc manner through capex works or when facilities are otherwise replaced or upgraded as required due to end of life or due to increased demand from organic growth of the network.

1.5.1.1. Cost/Benefit Analysis

The only benefit of this option is that it will avoid up-front capital expenditure. It is not, however, a costless option because non-conformance issues will still need to be addressed, but they will be addressed in an ad hoc reactive manner rather than a planned manner.

The other problem with this option is that deferring a planned program of works, or continuing with ad-hoc refurbishment, will continue to expose AGN to HSE, and operational risks. There is also potential for the condition and serviceability of city gate stations to deteriorate further and risks to increase. The risk associated with this option is therefore rated as High (see Appendix A).

Given the risks associated with this option and the fact that it would result in AGN failing to comply with regulatory and safety requirements, it is not considered a feasible option for a prudent operator and so is not considered in the quantitative cost benefit analysis in section 1.6.

1.5.2. Option 2 – 10 Year Refurbishment Program

The second option AGN has identified is to refurbish the 23 highest risk city gates over the next two AA periods (2018-2022 and 2023-2027). The refurbishment works include re-levelling city gate compounds, removing trip hazards, upgrading vehicle protection, upgrading site security, installing access ladders and upgrading signage.

In the first AA period (2018-2022) it would target 11 sites with the highest risk ranking, covering both the operational and HSE risks. Within the 11 sites identified for immediate action, sites would be grouped by location and type of work required, in order to maximise efficiency.

In the second AA period (2023-2027) the program would be repeated with the aim of treating the remaining 12 sites identified as high risk.

This would deliver risk reduction in both operational and HSE risks currently identified at 23 sites out of 51. In order to treat the already identified risk at the remaining sites (28)[3], and any

[3] 28 remaining sites comprise 26 sites with existing issues identified for action, and two new sites. Over the next 2 AA periods, it is expected that issues will arise at the 2 new sites that will require action in future AA periods.

hazards that emerge as these sites age, it will become necessary to upgrade them. Such upgrades are likely to occur beyond the 2023-2027 AA period.

1.5.2.1. Cost/Benefit Analysis

Benefits

With the refurbishment of 11 sites to be spread over the whole AA period, this option is considered achievable with the existing resources available, and offers a reduction in both operational and HSE risks over the 5 year period. Further, it complies with regulatory requirements as outlined in section 1.3.4 to maintain assets to the current standard and to minimise the risks and hazards associated with gas installations.

A planned program of works has the benefit of capturing efficiencies in the work to be performed. For example, grouping sites by geographic location yields savings on costs such as travel and accommodation for contractors, which can be as much as 10-30% of work package costs based on current project experience. Unquantified purchasing savings are also likely to be realised when performing similar upgrades at a number of city gate stations.

Costs

Based on quotes for similar work, the cost to treat the first 11 sites is estimated to be $412 ($000, real 2016) over the term of the next AA period.

The cost of refurbishment work at the next 12 sites is estimated to be $294 ($000, real 2016) for the AA period 2023-2027. This estimate is based on rectifying the already identified issues and assumes no further degradation of sites in the intervening time.

Increased future costs due to increased degradation of the remaining 28 untreated sites have been estimated as $21.1 ($000, real 2016) per site, based on the difference between the average cost to refurbish the worst 23 sites as proposed here, and the average cost to refurbish the remaining 28 sites given the issues identified at this time.

1.5.3. Option 3 – Comprehensive 5 year program

The third option AGN has identified is to refurbish the 23 highest risk city gates in the next AA period (2018-2022)

The program of works would target 23 sites for immediate action, as identified by the risk ranking, sites would be grouped by location and type of work required, in order to maximise efficiency.

This would deliver risk reduction in both operational and HSE risks currently identified at 23 sites out of 51. Of the remaining sites (28), it is likely that an ongoing upgrade program beyond the next AA period will be necessary to address lower level risks already identified, and any risks emerging as these sites age.

1.5.3.1. Cost/Benefit Analysis

Benefits

This option offers significant reduction in both operational and HSE risks over the 5 year period of the next AA period, with the residual risk falling from High to Moderate (see Appendix A).

By treating the 23 highest risk sites immediately, this option reduces the risk of a failure due to an already identified hazard. . Further, it complies with regulatory requirements as outlined in section 1.3.4 to maintain assets to the current standard and to minimise the risks and hazards associated with gas installations.

As with Option 2, a planned program of works has the benefit of capturing efficiencies in the work to be performed. For example, grouping sites by geographic location yields savings on costs such as travel and accommodation for contractors, which can be as much as 10-30% of work package costs based on current project experience. Unquantified purchasing savings are also likely to be realised when performing similar upgrades at a number of city gate stations.

By performing more work in the next AA period, the remaining 28 identified sites with lower risk ratings will not have aged as significantly as in Option 2, limiting the cost of any future refurbishment work at those sites. Based on the current estimates, the average cost of refurbishment per site for the 23 highest risk sites is $31 ($000, real 2016), while at the remaining sites, based on the existing/known hazards already identified, the refurbishment costs are estimated to average $9.7 ($000, real 2016) per site. The cost to refurbish these sites if they are left for 10 years or longer was recorded as a cost of $21.1 ($000, real 2016) per site in option 2. Therefore there is a benefit of $11.4 ($000, real 2016) per site.

Costs

Due to the higher volume of work that must be implemented over a five year period with this option, the costs include provision of a dedicated project manager, and additional costs for contractors to perform tasks that would be managed in-house under Option 2.

The total cost for this option is $1,470 ($000 real 2016), based on existing quotes for similar work, and includes $764 ($000, real 2016) for the provision of one FTE project manager for 5 years.

As stated above, a future cost of $1,035 ($000, real 2016) is required to refurbish the remaining 28 sites after the 2018-2022 AA period, based on the actions already identified at the remaining sites. No increase is predicted as these sites will are not expected to degrade significantly in the 5 year AA period.

1.6. Summary of Cost/Benefit Analysis

The table below provides a summary of the costs and benefits associated with each of the options.

Table 1.5: Summary of Cost/Benefit Analysis ($000, 2016)

Option	Benefits	Costs/Risks
Option 1	This option does not give rise to upfront capital expenditure, although AGN will incur costs for reactive works on rectifying some issues.	The city gates will not meet current standards or OH&S requirements. The risk associated with this option is therefore High.
Option 2	Significant reduction in both operational and HSE risks over a 10 year period	Costs of $706 ($000) comprising work on 23 city gate sites over 10 years, including expected future increase in costs due to deterioration of station assets. Total cost during the next AA period is $412 ($000), and for the following AA period is $294 ($000)
Option 3	Significant reduction in both operational and HSE risks over a 10 year period	Total cost of $2,505 ($000) comprising work on 51 city gate sites over 10 years, including provision for FTE project manager ($1,528 ($000)) Total cost during next AA period is $1,470 ($000)

A cost benefit analysis has been undertaken to quantitatively determine the least cost option, and the result of this analysis is shown in Table 1.6 below, which compares the net present value of the costs of:

- Option 2 - Institute a refurbishment programme over the ten years of the next and following AA Periods, and.
- Option 3 - Institute a refurbishment programme over the five years of the next AA Period.

As indicated in 1.5.1 above, the "Do Nothing" option is not considered a feasible option because it does not comply with current standards, OH&S requirements, or the general duties outlined in the Gas Safety Act. It has not therefore been included in the quantitative cost benefit analysis.

Options 2 and 3 require work to be executed over different time frames. In order to understand the cost of addressing the risks identified at all 51[4] sites, the time frame for each option was extended such that all sites would be refurbished at the completion of the given timeframe. In the case of Option 2 this required a 20 year period, while Option 3 would complete the work over a 10 year period.

Costs included the estimated cost of the work, which has been generated based on the issues identified for each site, with the cost of each activity based on current quotes. For Option 3, a benefit was recorded as the 28 lower risk sites will be refurbished sooner, reducing the costs associated with the work as there is expected to be less or no degradation compared to Option 2.

Table 1.6: Comparison of Options ($000, 2016)

				Next AA Period			Subsequent AA Periods	
Item	**NPV**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023-2042**	**Total**
Option 2	-971	-37	-74	-112	-112	-75	-885	-1,297
Option 3	-1,897	-245	-306	-306	-306	-306	-1,036	-2,186
Discount Rate (real pre-tax WACC)	**3.14%**							

Notes: Please see supporting Information 1 for more information

As this table shows, Option 2 is most cost effective of the two options[5] and also provides significant risk reduction over the term of the next AA period (see Appendix A). Given the results of this analysis, AGN has decided to implement Option 2 (the refurbishment of 23 city gates over 10 years from 2018 to 2027) at an estimated cost of $706 ($000, 2016) over the ten years, and $412 ($000, 2016) over the five years of the next AA period (2018-2022).

4 51 sites comprise 23 sites considered high risk, 26 sites with existing issues identified for action, and two new sites. Over the next two AA periods, it is expected that issues will arise at the 2 new sites that will require action in future AA periods.

5 An analysis period of 20 years has been chosen to model the benefits and costs associated with completing refurbishment works at the initial 23 sites and remaining 28 sites as outlined above. Option 2 requires 20 years to complete the work. Option 3 requires 10 years.

1.7. Proposed Solution

1.7.1. What is the Proposed Solution?

Option 2 is the preferred option, which will involve refurbishing 23 city gates over the next two AA periods with the refurbishment works including re-levelling city gate compounds, removing trip hazards, upgrading vehicle protection, upgrading site security, installing access ladders and upgrading signage.

This project will be executed over the next two AA periods, with the refurbishment of the first 11 sites to be carried out in the next AA period, which is considered achievable with the existing resources available, and offers a reduction in both operational and HSE risks over the 5 year period. In the following AA period, a further 12 sites will be refurbished.

1.7.2. Why are we Proposing this Solution?

Option 2 is being proposed because it is the most cost-effective solution (as highlighted in the cost benefit analysis results summarised above) and reduces the risks to human health and safety and operational risks to as low as reasonably practicable in a manner that balances cost and risk. Because this option targets the worst sites first,[6] it will result in the risk rating falling from High to Moderate in the next AA period. The other benefit of this option is that it can be carried out using internal resources, avoiding the added cost of a dedicated project manager that would be incurred under Option 3.

Finally, it is worth noting that this option is consistent with the findings from the stakeholder engagement program in which customers indicated that they value the current standard of reliability and are supportive of initiatives that maintain the reliability and safety of the network.

1.7.3. Forecast Cost Breakdown

The cost forecast for City Gate refurbishment is based on past work and current quotations. For each of the 23 sites considered for refurbishment under Option 2, the work required at each site has been assessed, and a standard cost applied. As the work is proposed over two AA periods, the total for each AA period is based on the sites to be refurbished.

The total cost to refurbish the 23 sites is estimated to be $706 ($000, 2016), of which $412 ($000, 2016) will be spent in the next AA period on 11 sites, at an average cost of $37.5 ($000, 2016) per site (see Appendix B for more detail).

The average annual cost for the second AA period is $24.5 ($000, 2016) for 12 sites. These costs are lower as the scope of works required is less involved given the condition of these sites is not as deteriorated as the sites due for refurbishment in the next AA period.

The volume of work outlined above was determined based on the estimated capacity to project manage this work, establish projects, and manage contractors with current resources available. This capacity was determined based on experience from similar projects, specifically where City Gate sites have been upgraded to increase capacity due to network expansion. Typically between one and three such upgrades can be completed in a calendar year.

It has been assumed that lessons learned from sites refurbished at the start of the AA period will be applied in subsequent years, therefore the volume of work increases after 2018 and 2019, as

6 The ranking used to determine which sites require treatment ensures that those presenting the highest risk are treated first, and is the basis for both Option 2 and Option 3.

shown in the table below. In addition, the unit rate assumes that the total cost to refurbish 11 sites in the next AA period, is spread equally across all 11 sites. In reality some sites require more work than others, however the exact order in which sites will be refurbished has yet to be determined. Variables such as risk rank, location, volume of work and contractor availability will determine the order in which sites are refurbished.

Table 1.7: Project Cost Estimate for the 2018-2022 AA Period ($000, 2016)

	2018	2019	2020	2021	2022	Total
Volume	1	2	3	3	2	11
Average Cost Per Site	$37.5	$37.5	$37.5	$37.5	$37.5	-
Total	**$37.5**	**$74.9**	**$112.4**	**$112.4**	**$74.9**	**$412**

* Numbers may not total due to rounding

1.7.4. Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN considers the forecast capex for this project to be:

- *Prudent* – The expenditure is necessary to ensure that the ongoing integrity of city gate equipment and sites is maintained and health and safety issues that could impact safety of AGN's personnel are minimised. It is also the most cost effective option and is therefore of a nature that a prudent service provider would incur.
- *Efficient* – There is not a significant reduction in risk for a 5-year program as against a 10-year program, and so an accelerated process is not proposed. The cost estimates for the various components of the works are based on previous work of a similar scope and current quotations for suppliers and contractors. The proposed expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur. The manner in which AGN intends the refurbishment works to be carried out (i.e. capturing cost efficiencies by grouping work of similar types and locations together), can also be considered efficient.
- *Consistent with accepted good industry practice* – The identification and rectification of city gate integrity issues and health and safety risks as outlined above, and the reduction of risk to as low as reasonably practicable in a manner that balances cost and risk is consistent with Australian Standard AS2885 and therefore in keeping with accepted and good industry practice.
- *Achieves the lowest sustainable cost of delivering pipeline services* – Delivering the project across the next AA two periods is the most cost-effective option and will allow the highest risk sites to targeted first, which will result in the lowest sustainable cost of delivering pipeline services over the longer run.

The capex can therefore be viewed as being consistent with rule 79(1)(a) of the NGR.

The proposed capex is also consistent with rule 79(1)(b), because the expenditure is necessary to:

- *maintain and improve the safety of services (rule 79(2)(c)(i))* – the proposed refurbishment works offer reduced risk of injury to the workforce, and reduced risk of a loss of supply.

- *maintain the integrity of services (rule 79(2)(c)(ii))* – the station refurbishment works improve integrity by reducing likelihood of vehicle impact on assets, and improving access of maintenance personnel; and
- *comply with a regulatory obligation or requirement (rule 79(2)(c)(iii))* – the proposed works ensure existing stations meet current Australian Standards and HSE regulations, in accordance with the Gas Distribution Code and Gas Safety Act.

Appendix A Risk Assessment

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Option Risk
Risk Untreated	**Likelihood**	*Likely*	*Possible*	*Possible*	*Possible*	*Possible*	*Unlikely*	*Unlikely*	**HIGH**
	Consequence	*Medium*	*Minor*	*Significant*	*Minor*	*Medium*	*Medium*	*Medium*	
	Risk Level	*High*	*Low*	*High*	*Low*	*Moderate*	*Moderate*	*Moderate*	
Residual Risk Option 1	**Likelihood**	*Likely*	*Possible*	*Possible*	*Possible*	*Possible*	*Unlikely*	*Unlikely*	**HIGH**
	Consequence	*Medium*	*Minor*	*Significant*	*Minor*	*Medium*	*Medium*	*Medium*	
	Risk Level	*High*	*Low*	*High*	*Low*	*Moderate*	*Moderate*	*Moderate*	
Residual Risk Option 2	**Likelihood**	*Possible*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Rare*	*Rare*	**MODERATE**
	Consequence	*Medium*	*Minor*	*Significant*	*Minor*	*Medium*	*Medium*	*Medium*	
	Risk Level	*Moderate*	*Low*	*Low*	*Low*	*Moderate*	*Low*	*Low*	
Residual Risk Option 3	**Likelihood**	*Possible*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Rare*	*Rare*	**MODERATE**
	Consequence	*Medium*	*Minor*	*Significant*	*Minor*	*Medium*	*Medium*	*Medium*	
	Risk Level	*Moderate*	*Low*	*Low*	*Low*	*Moderate*	*Low*	*Low*	

Appendix B Detailed Cost Breakdown

The following table indicates the expected cost and works to refurbish the 11 highest risk sites, as per the proposed option. The order and grouping of sites to be refurbished has yet to be determined.

RegNo	Site Name	Date Constructed	Level ground	Remove Isolated Trip Hazards	Upgrade Security	Install bar operated 2nd Gate	Install impact protection	Paint impact bollards	Replace site signage	Install WBH access ladder	**Total**
P4-108	Wangaratta	1975	$0	$3,500	$0	$3,500	$2,500	$650	$500	$1,500	**$12,150**
P8-001	Shepparton	1981	$37,000	$0	$15,000	$3,500	$2,500	$650	$500	$0	**$59,150**
P8-014	Sale	1969	$37,000	$0	$0	$3,500	$2,500	$650	$500	$1,500	**$45,650**
P4-148	Rosedale	1973	$37,000	$0	$0	$3,500	$2,500	$650	$500	$1,500	**$45,650**
P4-130	Moe	1980	$0	$3,500	$0	$3,500	$2,500	$650	$500	$0	**$10,650**
P5-022	Darnum	1997	$37,000	$0	$0	$3,500	$2,500	$650	$500	$0	**$44,150**
P4-134	Tatura	1982	$37,000	$0	$15,000	$3,500	$0	$650	$500	$1,500	**$58,150**
P4-163	Merrigum	1981	$37,000	$0	$15,000	$3,500	$0	$650	$500	$1,500	**$58,150**
P4-081	Drouin (Main Sth Rd)	1975	$37,000	$0	$15,000	$3,500	$2,500	$650	$500	$0	**$59,150**
P5-011	Benalla (Monsbent)	1985	$0	$3,500	$0	$3,500	$0	$650	$500	$1,500	**$9,650**
P4-164	Kyabram	1981	$0	$3,500	$0	$3,500	$0	$650	$500	$1,500	**$9,650**

Appendix C List of City Gate Sites to be Refurbished

23 City Gate Sites with Moderate and High Risk Issues

City Gate Site	Year Built	Summary of Risks
Wangaratta	1975	Trip hazards, emergency exit gate, impact protection, signage, WBH ladder
Shepparton	1981	Uneven surface, site security, emergency exit gate, impact protection, signage
Sale	1969	Uneven surface, emergency exit gate, impact protection, signage, WBH ladder
Rosedale	1973	Uneven surface, emergency exit gate, impact protection, signage, WBH ladder
Moe	1980	Trip hazards, emergency exit gate, impact protection, signage
Darnum	1997	Uneven surface, emergency exit gate, impact protection, signage
Tatura	1982	Uneven surface, site security, emergency exit gate, signage, WBH ladder
Merrigum	1981	Uneven surface, site security, emergency exit gate, signage, WBH ladder
Drouin (Main Sth Rd)	1975	Uneven surface, site security, emergency exit gate, impact protection, signage
Benalla (Monsbent)	1985	Trip hazards, emergency exit gate, signage, WBH ladder
Kyabram	1981	Trip hazards, emergency exit gate, signage, WBH ladder
Hampton Park	1988	Trip hazards, emergency exit gate, signage, WBH ladder
Healesville	1994	Uneven surface, site security, emergency exit gate, signage, WBH ladder
Benalla (Midland Highway)	1975	Emergency exit gate, impact protection, signage, WBH ladder
Echuca	1990	Trip hazards, site security, emergency exit gate, signage, WBH ladder
Trafalgar	1979	Uneven surface, emergency exit gate, impact protection, signage
Yarragon	1994	Uneven surface, emergency exit gate, impact protection, signage
Longwarry	1972	Trip hazards, site security, emergency exit gate, impact protection, signage.

Euroa	1980	Uneven surface, site security, emergency exit gate, signage
Traralgon	1976	Trip hazards, emergency exit gate, signage, WBH ladder
Koonoomoo	1998	Trip hazards, emergency exit gate, signage, WBH ladder
Rutherglen	1998	Trip hazards, emergency exit gate, signage, WBH ladder
Yarrawonga	1998	Trip hazards, emergency exit gate, signage, WBH ladder

Business Case – Capex V41

City Gate and Field Regulator Pipework Refurbishment

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	James Rudolph, *Field Maintenance Manager*
Approved By	Andrew Foley, *General Manager Victorian Networks*

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	Australian Gas Networks Limited (AGN) has 100 City Gate and Field Regulator stations within its s within its Victorian and Albury (NSW) regulated networks, including those in above ground kiosks, open air compounds and located within pits. These facilities perform the pressure reduction and control functions, from higher pressure transmission pipelines owned by pipeline entities into AGN's Victorian and Albury distribution networks. The pipe work, regulators, valves and fittings in these facilities are subject to a periodic touch-up painting program, which involves removing any local areas of peeling or de-laminated paint (ground back) and repainting. The paint touch-up process has generally maintained the coating in a fit state. However, the external condition at around half these sites is now reaching a level where touch up painting is no longer sufficient to effectively maintain the coating, with corrosion posing a real risk. The key risk posed by corrosion is that it can lead to a gas leak and/or component failure, which may result in a supply outage and health and safety risks. An in-situ repainting program is therefore required to address the risks posed by the condition of these assets.
Options Considered	The following options have been considered: 1 Option 1: No refurbishment program, continue to apply touch-up paint where required and replace components and pipe spools if they fail. 2 Option 2: Establish a program to repaint 50 sites over the next two Access Arrangement (AA) periods. 3 Option 3: Establish a program to repaint up to 50 sites over the next AA period.
Proposed Solution	Option 2 is preferred.
Estimated Cost	The forecast capital expenditure for this project is $510.5 ($000, 2016) over the next (2018 – 2022) Access Arrangement (AA) period, of which $255.2 ($000, 2016) will be spent in the next AA period and $255.3 ($000, 2016) in the subsequent AA period (2023-2027).
Consistency with the National Gas Rules	The repainting program complies with the new capital expenditure criteria in rule 79 of the National Gas Rules (NGR) because:

(NGR)	• 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)); and
	• it is justified under 79(2)(c) as it is required to:
	  • maintain and improve the safety of services (79(2)(c)(i));
	  • maintain the integrity of services (79(2)(c)(ii)); and
	  • comply with a regulatory obligation or requirement (rule 79(2)(c)(iii)).

Stakeholder Engagement	A key outcome of the stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Reliability and Safety themes as its implementation will allow AGN to maintain the safety of the network whilst continuing to provide a highly reliable supply of natural gas to customers by establishing a comprehensive repainting program to effectively manage the risk of a failure due to corrosion. More information detailing the results of the stakeholder engagement program is provided in Chapter 5 of the Access Arrangement Information document.
Supporting Information	• V41 Supporting Information 1 (NPV and Options Analysis 10yr)

1.3. Background

AGN has 100 City Gate and Field Regulator stations within its Victorian and southern NSW licence areas, including those in above ground kiosks, open air compounds and located within pits. These facilities perform the pressure reduction and control functions, from higher pressure transmission pipelines owned by transmission pipeline entities into the AGN Victorian distribution networks.

The preventative maintenance for these stations involves mechanical and instrumentation checks on a 6 month basis. Where necessary, local areas of peeling or de-laminated paint both the station pipework and equipment is removed (ground back) and the area is repainted, this work is conducted by internal operations staff during usual maintenance activities. The paint touch-up process has generally maintained the coating in a fit state. However, the external condition at around half these sites is now reaching a level where touch up painting is no longer sufficient to effectively maintain the coating. This is because the bulk of the protective paint has deteriorated to such an extent that corrosion of pipe work, regulators, valves and fittings is becoming a problem, as shown in Figure 1 below. The condition of the pipework shown below prior to painting is typical of the sites identified as highest risk and requiring attention.

Figure 1.1: Delaminating Paint and Corrosion in Field Regulator Pit – Alma Rd, Bundoora (2013)

Figure 1.2: Condition of Paint Immediately After Repainting (2013)

A recent Energy Safe Victoria (ESV) audit in December 2015 of 22 sites identified eight sites where paint deterioration was considered significant enough to warrant action. As a result of internal 5 yearly station integrity reviews at 50 sites, a further 18 stations have been identified as requiring significant paint remediation. With just over 35% of the field regulator and city gate sites visited by these audits requiring remediation immediately, a conservative estimate is that up to 50% of sites area may require repainting over the next five to ten years.

Energy Safe Victoria is charged with ensuring compliance with the Victorian Gas Safety Act 1997[1]. Part 3, Div 1, s32 of the Act, states that:

1 Gas Safety Act 1997 (Vic) section 32

"a gas company must manage and operate each of its facilities to minimise as far as practicable -

1. *the hazards and risks to the safety of the public and customers arising from gas; and*
2. *the hazards and risks of damage to property of the public and customers arising from gas".*

Therefore there is a clear regulatory obligation to take steps to reduce the risks associated with degraded paintwork. Further, the Australian Standard governing transmission pipelines, in Part 3 – Operation and Maintenance (AS2885.3)[2] requires that:

"Maintenance of stations shall ensure that -

1. *all devices and systems required to ensure the station operates within these limits are operable; and*
2. *the structural and pressure integrity of stations is not compromised over time."*

Compliance with AS2885 is called for through the Gas Distribution System Code[3].

While the volume of work proposed above is significant, some of the stations at which pipework requires repainting have also been identified for refurbishment in business case *V38 – City Gate Refurbishment.* Where possible, this work would be aligned for efficient use of internal operations and project management resources.

1.4. Risk Assessment

A risk assessment has been carried out using APA's established evaluation criteria, the results of which are summarised in the table below (see Appendix A for more detail). As the table highlights, the untreated Health and Safety, and Operational risks are High.

Table 1.3: Risk Rating

Risk Area	**Untreated Risk Level**
Health and Safety	High
Environment	Low
Operational	High
Customers	Low
Reputation	Low
Compliance	Low
Financial	Moderate
Untreated Risk Rating	**High**

2 AS2885.3 Section 8.1 "Basis of Section"
3 Gas Distribution System Code v11 Schedule 2

The key risk posed by the corroded pipework and fittings is that corrosion leads to gas leaks and/or component failure and results in the interruption of supply. City gate and field regulator stations typically supply significant geographic areas with thousands of users. The cost of a supply outage would therefore be significant in terms of relighting costs and, if the outage occurs over an extended period, Guaranteed Service Level payments may also need to be paid.

Furthermore, a loss of containment at a city gate or field regulator station may have health and safety impacts ranging from minor medical treatment injuries, through to more serious injuries, and in the most extreme cases serious consequences including disability or death. For example if workers or members of the public are present when a gas leak occurs, subsequent ignition of the resulting gas cloud is likely to cause major injury or death.

1.5. Options Considered

AGN has identified the following options to rectify the issues identified in section 1.3 and address the associated risks outlined in section 1.4, including:

- Option 1: Do nothing and continue to apply touch-up paint where required and replace components and pipe spools if they fail.
- Option 2: Establish a program repaint up to 50 sites over two AA periods.
- Option 3: Establish a program repaint up to 50 sites over the next AA period.

1.5.1. Option 1 – Do Nothing

The first option AGN has identified is to continue to apply touch-up paint where required and replace components and pipe spools if they fail.

1.5.1.1. Cost/Benefit Analysis

The only benefit of this option is that it will avoid up-front capital expenditure. It is not, however, a costless option because AGN will still need to apply touch-up paint and replace components and pipe spools if they fail.

Under this option, the paintwork at city gate and field regulator stations will continue to deteriorate, which may lead to a loss of supply or gas leaks due to failure of a component, or failure of the pipework. If this was to occur, AGN could incur significant costs relighting customers and potentially having to pay GSL payments. These costs are difficult to estimate given the range of sites and number of consumers connected to them, but if a city gate or field regulator fails and supply cannot be restored promptly, the on-cost to AGN could be significant.

The life of the external pipe work, valves and fittings can also be expected to be substantially reduced under this option, with an increased likelihood that assets will not realise their design life. Further future repairs are expected to be more expensive than refurbishment costs in the medium to longer term.

Under the Gas Safety Act it is a requirement that the risks associated with natural gas are managed and reduced as low as reasonably practicable. Further, AS2885.3 requires that:

Maintenance of stations shall ensure that -

1 all devices and systems required to ensure the station operates within these limits are operable; and

2 the structural and pressure integrity of stations is not compromised over time

This option does not materially reduce the risks identified above and is therefore not considered a feasible option. As a result this option is not considered in the quantitative cost benefit analysis in section 1.6.

1.5.2. Option 2 – 10 Year Repainting Program

The second option AGN has identified is to repaint the 50 city gates over the next two AA periods (2018-2022 and 2023-2027).

After assessing the condition of all sites, work in the first AA period (2018-2022) would target the 25 sites most in the worst condition (highest risk). Where possible, this work will be coordinated for sites that are to be refurbished as proposed in business case V38 and which also require repainting.

In the second AA period (2023-2027) the program would be repeated with the aim of treating the remaining 25 sites identified as high risk.

This volume of work is considered achievable using a combination of internal resources for project management and supervision, and external contractors to perform the work.

Further extension of this program may be required as other assets in the network age.

1.5.2.1. Cost/Benefit Analysis

Costs

The average cost per site to grit blast, prep and repaint station pipework in situ has been estimated as $10.2 ($000, 2016). This cost includes an internal project management resource and internal supervision and labour. Contractor costs have been estimated using current contract rates.

In the first AA period, the total capital cost of the proposed program is $255.2 ($000, 2016). Where possible, repainting work will be aligned with refurbishment work identified in the *City Gate Refurbishment* business case (V38). This will allow efficiencies for example with labour and travel to be captured.

Over the second AA period the capital cost of the proposed program is also $255.2 ($000, 2016), as the work volume is consistent in both years. As with the work over the first AA period, where possible, work will be aligned with refurbishment work at city gates.

As shown in the attached "V41 Supporting Information 1 (NPV and Options Analysis 15yr)" there is an operational cost included in the NPV analysis. This operational cost is associated with touch up painting of city gate pipework, as per current practice, and totals $25.9 ($000, 2016) over the next two AA periods. Once a city gate's pipework is repainted, touch up paint will not be required for 10 to 15 years resulting in reduced operational costs in future years. An allowance for touch up painting already forms part of AGN's base year operational costs, which is why this expenditure does not constitute a step change.

Benefits

This option effectively mitigates the risks associated with old, corroded and deteriorated paint work. In doing so, AGN can demonstrate compliance with the requirements of the Gas Safety Act and AS2885 as outlined above.

At the completion of the current cycle of proposed work (approximately 2027) the paint condition of the majority of city gates and field regulators will be in good condition, thereby reducing the ongoing maintenance costs in future AA periods.

1.5.3. Option 3 – 5 Year Repainting Program

The third option AGN has identified is to repaint all of the 50 sites over the next AA period (2018-2022). In a similar manner to Option 2, this work would, where possible, be coordinated for sites that are to be refurbished as proposed in V38 and which also require repainting.

This option would deliver risk reduction more rapidly than Option 2, however to achieve this volume of work over a five year period would require the addition of a project management resource, or the contracting of work to an external project management and supervision provider resulting in higher costs.

1.5.3.1. Cost/Benefit Analysis

Costs

The total cost of the proposed program over the next AA period is $900.35 ($000, 2016). The average cost per site to grit blast, prep and repaint station pipework in situ has been estimated as $13.9 ($000, 2016), excluding the cost of an external project manager. The per unit cost includes contractor supervisor and labour cost in addition to internal supervisor and fitter costs. The painting contractor costs have been estimated using current contract rates. Due to the volume of work, an external project manager has been costed for 6 weeks each year to plan and implement the program, at a total cost of $205.2 ($000, 2016).

As shown in the attached "V41 Supporting Information 1 (NPV and Options Analysis 10yr)" there is an operational cost included in the NPV analysis. This operational cost is associated with touch up painting of city gate pipework, as per current practice, and total $21.95 ($000, 2016) over the next two AA periods. Once a city gate's pipework is repainted, touch up paint will not be required for 10 to 15 years, resulting in reduced future operational costs. An allowance for touch up painting already forms part of AGN's base year operational costs, which is why this expenditure does not constitute a step change.

Benefits

This option effectively mitigates the risks associated with old, corroded and deteriorated paint work. In doing so, AGN can demonstrate compliance with the requirements of the Gas Safety Act and AS2885 as outlined above.

At the completion of the current cycle of proposed work (approximately 2023) the paint condition of the majority of city gates and field regulators will be in good condition, thereby reducing the ongoing maintenance costs in future AA periods.

1.6. Summary of Cost/Benefit Analysis

The table below provides a summary of the costs

Table 1.4: Summary of Cost/Benefit Analysis

Option	Benefits	Costs/Risks
Option 1	Increasing risk of failure resulting in high replacement and repair cost. Increasing risk of corrosion, resulting in a gas leak, component failure or supply interruption, which could result in AGN having to make Guaranteed Service Level (GSL) payments and incurring relighting costs. These costs have not been taken into account Does not meet general duties requirements of Gas Safety Act, or maintenance requirements of AS2885.3	Defers cost of refurbishment into the future
Option 2	Total capex cost over 2 AA periods of $510.4 ($000, 2016), Capex cost over next AA period $255.2 ($000, 2016) Opex cost over 2 AA periods $25.9 ($000, 2016) Opex cost over next AA period $14.6 ($000, 2016)	Reduces residual risk to low. Satisfies general duties requirements of Gas Safety Act, or maintenance requirements of AS2885.3 Achievable volume of work with no need for external project management resources
Option 3	Capex cost over next AA period $900.3 ($000, 2016) Opex cost over next AA period $12.0 ($000, 2016) Volume of work necessitates use of external project management resources	Reduces residual risk to low more quickly than Option 2. Satisfies general duties requirements of Gas Safety Act, or maintenance requirements of AS2885.3

A cost benefit analysis has been undertaken to quantitatively determine the least cost option, and the result of this analysis is shown in Table 1.5 below, which compares the net present value of the costs of:

- Option 2: Institute a repainting program to repaint pipework at 50 sites over the next two AA periods; and
- Option 3: Institute a repainting program to repaint pipework at 50 sites over the next AA period.

As indicated in 1.5.1 above, the "Do Nothing" option is not considered a feasible option because of the risks associated with this option and because it would result in AGN failing to meet its obligation to maintain assets in a prudent and safe manner. As outlined above, this obligation arises from the Gas Safety Act general duties, which specify that:

> *"A gas company must manage and operate each of its facilities to minimise as far as practicable -*
>
> 1. *the hazards and risks to the safety of the public and customers arising from gas; and*
> 2. *the hazards and risks of damage to property of the public and customers arising from gas"*

And further, the maintenance requirements of AS2885.3 which state that:

"Maintenance of stations shall ensure that—

1. *all devices and systems required to ensure the station operates within these limits are operable; and*
2. *the structural and pressure integrity of stations is not compromised over time."*

Therefore Option 1 has not been included in the quantitative cost benefit analysis.

The quantitative analysis has been conducted over three AA periods in order to capture the time period to refurbish all 50 city gate and field regulator stations identified in section 1.3 as requiring paint refurbishment. Once all 50 city gates have been repainted, a sustainment rate of 1 per year was included. Operational costs and associated savings which occur in future AA periods have also been captured for comparison.

Table 1.5: Summary Cost Benefit Analysis Option Comparison ($000, 2016)

	NPV 2016	Next AA Period					Subsequent AA Periods	
Item		**2018**	**2019**	**2020**	**2021**	**2022**	**2023-2032**	**Total**
Option 2	**-453**	34	54	74	64	43	**266**	**536**
Option 3	**-832**	142	197	224	210	140	**-**	**912**
Discount Rate (real pre-tax WACC)	**3.14%**							

As Table 1.5 shows, Option 2 is the most cost effective of the two options and also provides significant risk reduction over the term of the next AA period (see Appendix A). Given the results of this analysis, AGN has decided to implement Option 2 at an estimated cost of $270 ($000, 2016) over the next AA period.

1.7. Proposed Solution

1.7.1. What is the Proposed Solution?

Option 2 is the preferred solution and will involve repainting 50 city gate and field regulator stations where paint has been identified as significantly degraded, with the work spread equally over the next two AA periods.

1.7.2. Why are we Proposing this Solution?

Option 2 is being proposed because it is the most cost-effective solution (as highlighted in the cost benefit analysis results summarised above) and reduces the risks to human health and safety and operational risks to as low as reasonably practicable in a manner that balances cost and risk. Because this option targets the worst sites first,[4] it will result in the risk rating falling from High to Moderate in the next AA period. This option also satisfies the regulatory requirements as

[4] The ranking used to determine which sites require treatment ensures that those presenting the highest risk are treated first, and is the basis for both Option 2 and Option 3.

previously outlined. The other benefit of this option is that it can be carried out using internal resources, avoiding the added cost of a dedicated project manager that would be incurred under Option 3.

Finally, it is worth noting that this option is consistent with the findings from the stakeholder engagement program in which customers indicated that they value the current standard of reliability and are supportive of initiatives that maintain the reliability and safety of the network.

1.7.3. Forecast Cost Breakdown

The forecast cost of Option 2 is set out in Table 1.6.

The cost for each year of the proposed program was determined based on the average cost to repaint a station. The overall project is expected to be managed using internal resources, however the costs for each site include of one day each for a program co-ordinator, an internal supervisor, and internal fitter's labour. Internal labour costs are based on current internal labour rates, and the painting contractor's labour is based on current contract prices. The average cost to repaint city gate and field regulator sites in situ is $10.2 ($000, 2016) per site.

The total capital cost of the proposed program is $255.2 ($000, 2016) in each of the two AA periods that the program is proposed to be implemented in, as the work volume is the same in both AA periods.

Table 1.5 outlines the volume of work and cost estimate over the next AA period. The phasing is such that there is a gradual increase in work volume over the first three years of the AA period as the program is established. The decline towards the end of the AA period is to allow for increased volume if necessary. As indicated in the cost/benefit discussion above, where possible this work will be aligned with City Gate Refurbishment work (V38) to capture efficiencies in reduced travel time, labour duplication and scheduling.

Table 1.6: Project Cost Estimate for the Next AA Period ($000, 2016)

	2018	2019	2020	2021	2022	Total
Volume	3	5	7	6	4	25
Ave Capital Cost	$10.21	$10.21	$10.21	$10.21	$10.21	$10.2
Total Capital Cost	**$30.6**	**$51.1**	**$71.5**	**$61.3**	**$40.8**	**$255.2**

1.7.4. Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN considers the forecast capex for this project to be:

- *Prudent* – The expenditure is necessary to ensure that the ongoing integrity of city gate equipment and sites is maintained. The expenditure is also of a nature that a prudent service provider would incur.
- *Efficient* – There is not a significant reduction in risk for a 5-year program as against a 10-year program, and so an accelerated process is not proposed. The cost estimates for repainting are based on previous work of a similar scope and current contractor rates. The proposed expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur. The manner in which AGN intends the

repainting works to be carried out (i.e. coordinating work where possible with city gate refurbishment (V38) works), can also be considered efficient.

- *Consistent with accepted good industry practice* – The identification and rectification of city gate integrity issues and health and safety risks as outlined above, and the reduction of risk to as low as reasonably practicable in a manner that balances cost and risk is consistent with Australian Standard AS2885 and therefore in keeping with accepted and good industry practice.
- *Achieves the lowest sustainable cost of delivering pipeline services* – Delivering the project across the next AA two periods is the most cost-effective option and will allow the highest risk sites to targeted first, which will result in the lowest sustainable cost of delivering pipeline services over the longer run.

The capex can therefore be viewed as being consistent with rule 79(1)(a) of the NGR. The proposed capex is also consistent with rule 79(1)(b), because the expenditure is necessary to:

- *maintain and improve the safety of services (rule 79(2)(c)(i))* – safety is improved by reducing the likelihood of a city gate or field regulator set failing and releasing gas which presents a hazard to AGN operational staff, the consumer's staff, members of the public and property of the consumer or public.
- *maintain the integrity of services (rule 79(2)(c)(ii))* – the proposal to re-paint assets in degraded condition is a direct action to maintain the integrity of pipework and components in city gates and field regulators, to prevent degradation or failure as a result of corrosion due to exposure to the elements.
- *comply with a regulatory obligation or requirement (rule 79(2)(c)(iii))* – the proposed repainting of city gate and field regulator pipework meets the requirement of AS2885.3[5] – that:

  "Maintenance of stations shall ensure that—

  1. *all devices and systems required to ensure the station operates within these limits are*
     operable; and
  2. *the structural and pressure integrity of stations is not compromised over time."*

  and the Gas Safety Act 1997 Part 36, Div 1, s32 which states that:

  "a gas company must manage and operate each of its facilities to minimise as far as practicable -

  1. *the hazards and risks to the safety of the public and customers arising from gas; and*
  2. *the hazards and risks of damage to property of the public and customers arising from gas."*

[5] AS2885.3 Section 8.1 "Basis of Section"
[6] Gas Safety Act 1997 (Vic) section 32

Appendix A Risk Assessment

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Option Risk
Risk Untreated	**Likelihood**	*Unlikely*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	**HIGH**
	Consequence	*Major*	*Minor*	*Significant*	*Minor*	*Minor*	*Medium*	*Medium*	
	Risk Level	*High*	*Low*	*High*	*Low*	*Low*	*Moderate*	*Moderate*	
Residual Risk Option 1	**Likelihood**	*Unlikely*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	**HIGH**
	Consequence	*Major*	*Minor*	*Significant*	*Minor*	*Minor*	*Medium*	*Medium*	
	Risk Level	*High*	*Low*	*High*	*Low*	*Low*	*Moderate*	*Moderate*	
Residual Risk Option 2	**Likelihood**	*Rare*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	**MODERATE**
	Consequence	*Major*	*Minor*	*Significant*	*Minor*	*Minor*	*Medium*	*Medium*	
	Risk Level	*Moderate*	*Low*	*Moderate*	*Low*	*Low*	*Moderate*	*Moderate*	
Residual Risk Option 3	**Likelihood**	*Rare*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	**MODERATE**
	Consequence	*Major*	*Minor*	*Significant*	*Minor*	*Minor*	*Medium*	*Medium*	
	Risk Level	*Moderate*	*Low*	*Moderate*	*Low*	*Low*	*Moderate*	*Moderate*	

Appendix B Detailed Cost Breakdown

[redacted]

Business Case – Capex V44

Transmission & Network Isolation Valve Replacement

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	Michael Gallagher, *Engineering Manager*
Approved By	Andrew Foley, *General Manager Victorian Networks*

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	Australian Standards AS2885.1 and AS4645.1 require isolation valves to be installed for emergency management and maintenance purposes. Through the routine preventative maintenance program, Australian Gas Networks (AGN) has identified four isolation valves that are seizing and require replacement because they pose a risk to human health and safety and the operation of the network. One of these valves is located at a major intersection and needs to be relocated because it poses an occupational health and safety risk (OH&S) to operational personnel. If the seized isolation valves are not replaced, then an expedient response to an emergency on the pipeline would be hindered, which could affect the safety and integrity of services. If such a situation were to occur there would be two options available to manage the leak: • close alternative transmission or network valves, which means that a larger number of customers would be affected; or • mobilise an emergency repair crew to complete a flow stopping operation, which would come at considerable cost and delay (i.e. in excess of $100,000 and up to 48 hours after the event depending on the availability of equipment from emergency contractors). In both of these cases, the cost to customers could be quite significant, which underscores the importance of replacing the seized valves.
Options Considered	The following options have been considered: 1 Option 1: Do nothing (i.e. maintain existing seized valves). 2 Option 2: Replace the network isolation valves at 4 locations.
Proposed Solution	Option 2 has been selected because it is the most cost effective way of managing the risks associated with seized valves and is consistent with AS2885.1 and AS4645.1.
Estimated Cost	The forecast capital expenditure (capex) for this project over the next (2018 – 2022) Access Arrangement (AA) period is $633.76 ($000, 2016)
Consistency with the National Gas Rules	The proposal to replace isolation valves at 4 pressure regulating facilities complies with the new capex criteria in rule 79 of the National Gas Rules (NGR) because:

(NGR)	• 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)); and
	• it is justified under 79(2)(c) as it is required to:
	  • maintain and improve the safety of services (79(2)(c)(i));
	  • maintain the integrity of services (79(2)(c)(ii)) and
	  • comply with a regulatory obligation or commitment (79(2)(c)(iii)).

Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is consistent with the Safety theme as its implementation will allow us to maintain the safe supply of natural gas to customers by maintaining isolation valves in optimum condition to allow a quick, effective response to a potential incident More information detailing the results of AGN's stakeholder engagement program is provided in Chapter 5 of our Access Arrangement Information document.

1.3. Background

Australian Standards AS2885.1 (Pipelines - Gas and Liquid petroleum) and AS4645.1 (Gas distribution network management) require transmission pipeline and network operators to install and maintain isolation valves to allow for expedient isolation of the pipeline or network for emergency and maintenance purposes (see Appendix B for the relevant excerpts). The quantity and location of these valves will depend on the design of the asset, the valve location (urban vs rural), the pipe material used and the consequences of any loss of containment.

AGN's Victorian and Albury networks consist of 167 transmission valves (branch and mainline valves) and 169 critical network valves. The operations of these valves are checked continuously under a preventative maintenance program by System Operation personnel.

The preventative maintenance program has identified one transmission main line valve (T14-LV02), one transmission branch valve (T13-BV05) and two CBD network isolation valves (TCHP-LV01 and TCHP-LV03) that have seized and are inoperable. The isolation valves in the latter of these cases are in the City High Pressure distribution network, which supplies approximately 41,700 customers in Melbourne CBD. Isolation valve TCHP-LV01 is critical to the supply of gas to approximately 20,000 of these CBD customers. Given the density of occupied buildings in the CBD and the number of people who reside or work in the CBD, operational isolation valves are of critical importance. Currently, the risk of seizure is managed by the injection of anti-seizure lubricant by operational personnel during the preventative maintenance schedule.

In addition to these issues, the transmission branch valve, T13-BV05, is located in a major intersection of Mornington-Tyabb Rd and Frankston-Flinder Rd, which means that operating this valve poses an occupational health and safety (OH&S) risk to operational personnel.

Table 1.3 below provides a summary of the 4 isolation valves, while Appendix A shows the location of the valves.

Table 1.3: Transmission and Network Isolation Seized Valves

Facility ID	Valve Location	Valve Type	Maximo Asset Number
TCHP-LV01	William St, Melbourne	CBD network isolation valve	1028960
TCHP-LV03	Queens St, Melbourne	CBD network isolation valve	1028962
T013-BV05	Tyabb Rd, Mornington 3931	Transmission branch valve	1028356
T14 LV02	Frankston-Dandenong Rd, 3175	Transmission mainline valve in pit	1011222

Seizing valves reduces the ability of AGN operations staff to isolate transmission pipelines or sections of the distribution network in the event of an emergency or for maintenance. In response to an emergency, operations personnel would be dispatched to operate the valve, typically within a one to two hour time frame. Without correctly functioning valves, two other options would have to be considered for isolation:

- Shut down alternative isolations valves on the pipeline or network – The problem with this option is that it widens the group of customers that would be affected by the loss of supply because a wider area would be impacted.
- Mobilise a specialist emergency contractor – The problem with this option are that it costs a considerable amount to mobilise a contractor (>$100k), there is a time delay with mobilising contractors (minimum 24 hours) and it is also dependent on the availability of contractor crews and equipment.

AGN has an existing program of works to replace seizing valves. In 2016, Watsonia Rd and Langwarrin will be completed under this program. Given the age of the network and valves, it is anticipated that occurrences of valve seizures will continue which will require operational management and future replacement programs.

1.4. Risk Assessment

A risk assessment has been carried out using APA’s established evaluation criteria (detailed in Appendix A – Risk Assessment) to produce an estimated level of risk, which is summarised in Table 1.4. As this table highlights the untreated risks associated with the four valves has been assessed as "High”.

Table 1.4: Risk Rating

Risk Area	Untreated Risk Level
Health and Safety	High
Environment	Negligible
Operational	High
Customers	Moderate
Reputation	Moderate
Compliance	Moderate
Financial	Negligible
Untreated Risk Rating	**High**

The key risks are to health and safety (particularly the safety risk to the public) and operations. Transmission and network isolation valves are key components of the pipelines and network. The valves are required to be operational for maintenance activities or to isolate the pipelines or network during emergencies. Maintenance and emergency response within the Victorian and Albury networks would be seriously impeded if a valve were not operational when required. Isolations would need to be made at other locations, which would affect much larger parts of the network than if the seized valve could simply be turned off. Currently, the risk of seizure is managed by the injection of anti-seizure lubricant by operational staff.

There is an additional OH&S risk for transmission branch valve T013-BV05. This valve is located at the intersection of Mornington-Tyabb Rd and Frankston-Flinders Rd, which is a major intersection. Operation of this valve requires complex traffic management and lane shutdowns. In the event of an emergency, arranging traffic management approvals with local road authority may not be expedient. In addition, the depth of cover of this valve inhibits the ability of System Operations to maintain it in optimum condition.

1.5. Options Considered

AGN has identified the following options to address the safety related risks outlined in section 1.4:

- Option 1: Do nothing; or
- Option 2: Replace the network isolation valves at four locations.

1.5.1. Option 1 – Do Nothing

The "do nothing" option in this case would see the periodic valve maintenance by System Operations personnel continue under the current scheduled program and the four seized valves left in place. Under this option the seized valves would continue to be maintained under this program to the extent that they can be.

1.5.1.1. Cost/Benefit Analysis

The benefit of this option is that it does not give rise to any upfront replacement costs. However, the health and safety and operational risks outlined in section 1.4 would continue to exist, with the untreated risk remaining high (see Appendix A).

1.5.2. Option 2 – Isolation valves replacement program

This option entails the replacement of the identified transmission and network valves at four locations with approved specification valves. In addition, the transmission branch valve, T13-BV05, will need to re-located as the current location is situated in a major intersection.

1.5.2.1. Cost/Benefit Analysis

The benefits of this option are that:

- quick and effective isolation of the transmission pipeline and distribution network within Melbourne CBD will be possible for maintenance or during an emergency, removing the risk that large areas of downstream customers are affected because of the need to isolate at other sites;
- due to the location of T013-BV05 at a major intersection, the OHS risk to personnel operating the valve will be removed; and

- the residual risk associated with the valves at these locations will be reduced from High to Moderate (see Appendix A).

The cost of replacing the four isolation valves and relocating T013-BV05 is estimated to be $633.76 ($000, 2016) (see section 1.7.3 for more detail). This estimate is based on actual costs of similar projects recently completed.by AGN.

1.6. Summary of Cost/Benefit Analysis

A summary of the costs and benefits of the two options is shown in Table 1.5 below.

Table 1.5: Summary of Cost/Benefit Analysis

Option	Benefits	Costs/Risks
Option 1: Do nothing	No upfront capital expenditure on new valves	AGN would be unable to isolate the pipeline or network at these four locations, which means that supply to a larger number of customers could be affected in the event of an emergency in these locations. The health and safety and operational risks associated with these valves would remain high. The OH&S risk for valve T013-BV05 would remain. AGN would not comply with the provisions in AS2885 and AS4645 relating to isolation valves.
Option 2: Isolation valve replacement program at 4 locations	Replacing the valves at the four locations will mean that the valves can operate as they are intended and permit the quick and effective isolation of transmission pipelines and network for maintenance or emergencies. Moving the valve T013-BV05 would also address the OH&S risks currently posed by the location of this valve. The health and safety and operational risks associated with these valves would fall from high to moderate. Addresses regulatory compliance for isolation valves in accordance with AS2885 and AS4645.	Capex: $633.76 ($000, 2016)

1.7. Proposed Solution

1.7.1. What is the Proposed Solution?

AGN proposes to replace the identified isolation valves at the four locations (Option 2) and to relocate the transmission branch valve (T013-BV05).

1.7.2. Why are we Proposing this Solution?

AGN is proposing to implement Option 2 because it is the most cost-effective way of managing the risks associated with the seized valves and is consistent with the requirements set out in AS2885 and AS4645. Implementing this option will mean that transmission pipelines and the

Melbourne CBD network can be isolated in the event of an emergency or for maintenance. The risks to public safety will be reduced, the number of affected customers will be reduced and scheduled maintenance can proceed without hindrance. Relocating valve T013-BV05 will also reduce the OH&S risks associated with this valve.

Option 1 is not being proposed, as it is inconsistent with the requirements of AS2885 and AS4645 and will not reduce the risk associated with these valves to as low as reasonably practicable (ALARP).

AGN has also taken into account the following factors in the selection of this solution:

- *Technical* – A replacement program addresses the issue of seizing isolation valves. There is no other low cost solution that would address the issue.
- *Cost Effectiveness* – The replacement program is the only effective solution that addresses the issue of seized valves. To not replace the valves would expose AGN to much higher costs in the event of an emergency incident on the transmission pipeline lines or within the Melbourne CBD. An emergency incident would require the mobilisation of a specialist emergency repair contractor with a minimum mobilisation time of 24 hours and the closure of alternative isolation valves. Closure of alternative isolation valves would affect a greater number of customers, particularly in the Melbourne CBD. It could also lead to relatively high rectification costs, given the costs associated with relighting and the potential for AGN to have to make Guaranteed Service Level payments if customers cannot be restored within 12 hours.
- *Project delivery* – This project will be delivered by December 2022. This will allow the program of works to coincide with other planned works such as the Cast Iron Mains Replacement Program within the Melbourne CBD and transmission pipeline intelligent pigging programs. This allows an efficient use of resources, which will be required to complete the works. The works will be completed using existing resources (both internal and external labour).
- *Stakeholder feedback* - AGN has undertaken a comprehensive engagement program to better understand the values of stakeholders. During this engagement, stakeholders noted that they valued initiatives that improve the safety, reliability and customer service of the network. Consistent with these three insights, replacement of the identified valves will increase safety, increase reliability and reduce the number of customers affected if an incident occurred.

1.7.3. Forecast Cost Breakdown

The scope of works to replace the identified valves includes:

- *Design and Planning* – Detailed alteration designs will be required for each of the 4 valve locations. These designs will need to meet all the regulatory requirements. AGN will also need to obtain Energy Safe Victoria’s (ESV) consent to construct and operate the new valves.
- *Procurement* – AGN will need to procure the specified valves from its approved supply panel. The panel contains pre-approved suppliers, which ensures reduced procurement lead time and competitive pricing of materials.
- *Installation* – A mix of internal and external resources will be required to remove the existing valves and install the new valves. This installation will coincide with other planned AGN works, such as the cast iron mains replacement program and transmission pipeline pigging. This will allow efficient use of resources and minimise operational risks.
- *Commissioning* – Once the valves are installed they will need to be commissioned by AGN operations personnel.

- *Change management* – Once the valves are commissioned the pipeline drawings will need to be updated to reflect changes. The Maximo asset management system will also need to be updated with changes and ensure the preventative maintenance program meets AGN requirements.

Tables 1.6 and 1.7 set out the forecast cost of carrying out this project, which is based on similar works that have recently been completed in AGN's Victorian network. In arriving at this estimate, the following assumptions have been made about the scope of work for each valve:

- TCHP-LV01 is located in the Melbourne CBD. Road closure with after hours or weekend works will be required. Works to be programmed during Melbourne CBD cast iron mains replacement for efficiency.
- TCHP-LV03 is located in the Melbourne CBD. Road closure with after hours or weekend works will be required. Works to be programmed during Melbourne CBD cast iron mains replacement for efficiency.
- T013-BV05 is located at major intersection. Road closure with after hours or weekend works will be required.
- T14 LV02 valve to be replaced with valve suitable for intelligent pig, to allow for future inspection of the transmission pipeline. Replacement valve will not be the same length of existing valve (face to face). Therefore replacement of valve will require altering the pipe work within the existing valve pit.

More detailed cost estimates are contained in Appendix D.

Table 1.6: Estimated Cost of Isolation Valve Replacements ($000, 2016)

Valve ID	Item	Cost
TCHP-LV01, William St CBD	Material	[redacted]
	Site Works	[redacted]
	Design, Planning & PM	[redacted]
Sub-Total		[redacted]
TCHP-LV03, Queens St CBD	Material	[redacted]
	Site Works	[redacted]
	Design, Planning & PM	[redacted]
Sub-Total		[redacted]
T013-BV05, Mornington-Tyabb Rd	Material	[redacted]
	Site Works	[redacted]
	Design, Planning & PM	[redacted]
Sub Total		[redacted]
T14 LV02, Frankston-Dandenong Rd	Material	[redacted]
	Site Works	[redacted]
	Design, Planning & PM	[redacted]
Sub Total		**108.3**
Program Total		**633.7**

Table 1.7: Capex ($000, 2016)

	2018	2019	2020	2021	2022	Total
Materials	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Site Works	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Design, planning & PM	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	**99.6**	**97.5**	**114.8**	**213.5**	**108.3**	**633.7**

Note: proposed spend on T013-BV05 to be spread over 2020 and 2021.

1.7.4. Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN considers the forecast capex for this project to be:

- *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. Maintaining transmission and network in optimum condition for maintenance and emergencies is a necessary expenditure.
- *Efficient* – The valve replacement program will use existing internal and external labour resources that have extensive experience in completing this work in a safe and cost effective manner, with external labour to be obtained through a competitive tendering process. Materials will also be sourced through AGN's procurement panel of suppliers, which has been established through a competitive procurement process. The expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur. In addition, the CBD network isolation valves works would be conducted during the cast iron mains replacement program for efficiency.
- *Consistent with accepted and good industry practice* – Addressing the risks associated with the seizing transmission and network isolation valves 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 Standards AS4645 and AS2885.
- *To achieve the lowest sustainable cost of delivering pipeline services* – Replacing the seizing transmission and network isolation valves in a planned manner will result in a lower sustainable cost of delivering pipeline services over the longer term because it will avoid the costs of obtaining specialist emergency repair contractors and the costs that will be imposed on customers if a greater section of the network needs to be isolated..

The capex can therefore be viewed as being consistent with rule 79(1)(a) of the NGR. The proposed capex is also consistent with rule 79(1)(b), because the expenditure is necessary to:

- *maintain and improve the safety of services (rule 79(2)(c)(i))*; Maintenance and emergency response within the network would be impeded if a valve were not operational when required,
- *maintain the integrity of services (rule 79(2)(c)(ii))*; Maintaining these critical vales minimises the impact of maintenance and emergency operations. If a valve were not operational when required, I\isolations would need to be made at other locations, which would affect much larger parts of the network.
- *comply with a regulatory obligation or commitment (79(2)(c)(iii)):* Network isolation points are a requirement under both AS2885 and AS4645. The Network Safety Case and Emergency Plans identify these valves as critical assets.

Appendix A Risk Assessment

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels
Risk Untreated + Option 1 - Do nothing	**Likelihood**	*Occasional*	*Unlikely*	*Occasional*	*Unlikely*	*Unlikely*	*Occasional*	*Unlikely*	
	Consequence	*Major*	*Insignificant*	*Major*	*Medium*	*Medium*	*Medium*	*Insignificant*	
	Risk Level	*HIGH*	*Negligible*	*HIGH*	*Moderate*	*Moderate*	*Moderate*	*Negligible*	**HIGH**
	Likelihood	*Possible*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	
Residual Risk Option 2 Isolation valve replacement	**Consequence**	*Medium*	*Insignificant*	*Insignificant*	*Insignificant*	*Insignificant*	*Minor*	*Insignificant*	
	Risk Level	*Moderate*	*Negligible*	*Negligible*	*Negligible*	*Negligible*	*Low*	*Negligible*	*Moderate*

Appendix B AS4645.1 and AS2885.1 excerpts on pipeline/network isolation.

AS4645

4.9 SECTIONAL ISOLATION

4.9.1 General

The design of sectional isolation shall be in accordance with the results of the FSA or operational requirements of the network, including those relating to—

(a) operating pressure;

(b) the volume of gas;

(c) material type;

(d) operating and maintenance requirements;

(e) accessibility;

(f) local physical conditions including earthquakes, landslides and floods;

4.9.2 Isolation valve requirements

Isolation valves shall comply with the following:

(a) An isolation valve, and associated fittings and accessories, shall be fit for purpose and the design shall ensure compliance with relevant Standards nominated. The specific requirements of AS/NZS 4645.2 and AS/NZS 4645.3 shall apply as appropriate to the pipe network material.

AS2885.1

4.6.4 Isolation valves

Valves shall be provided to isolate the pipeline in segments for maintenance, operation, repair and for the protection of the environment and the public in the event of loss of pipeline integrity. The position and the spacing of valves shall be approved.

The location of valves shall be determined for each pipeline. An assessment shall be carried out and the following factors shall be considered:

(a) The fluid.

(b) The security of supply required.

(c) The response time to events.

(d) The access to isolation points.

(e) The ability to detect events which might require isolation.

(f) The consequences of fluid release.

(g) The volume between isolation points.

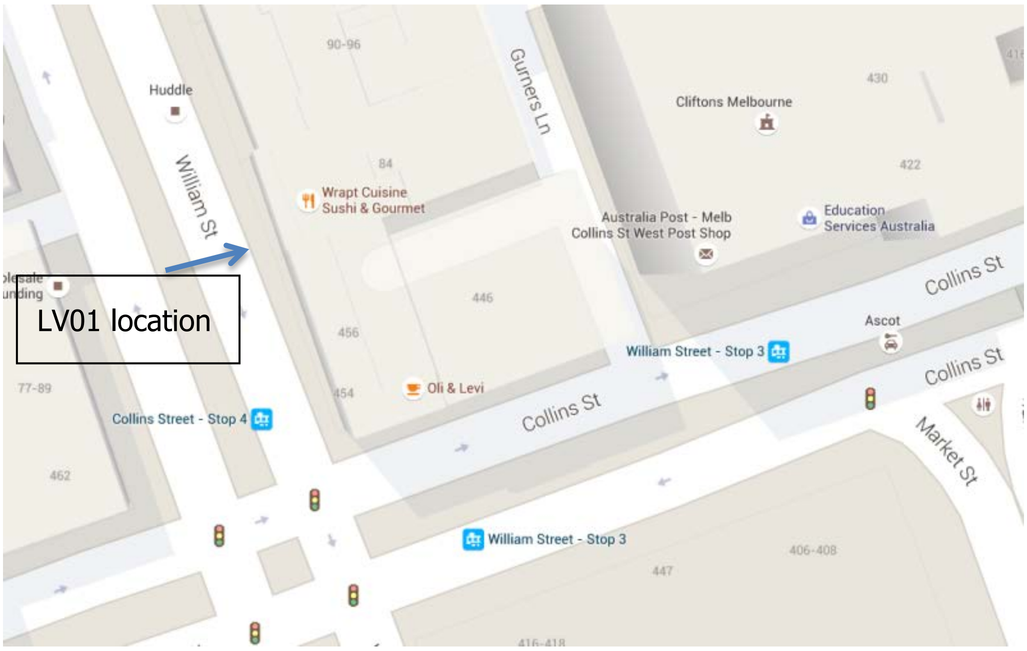
(h) The pressure.

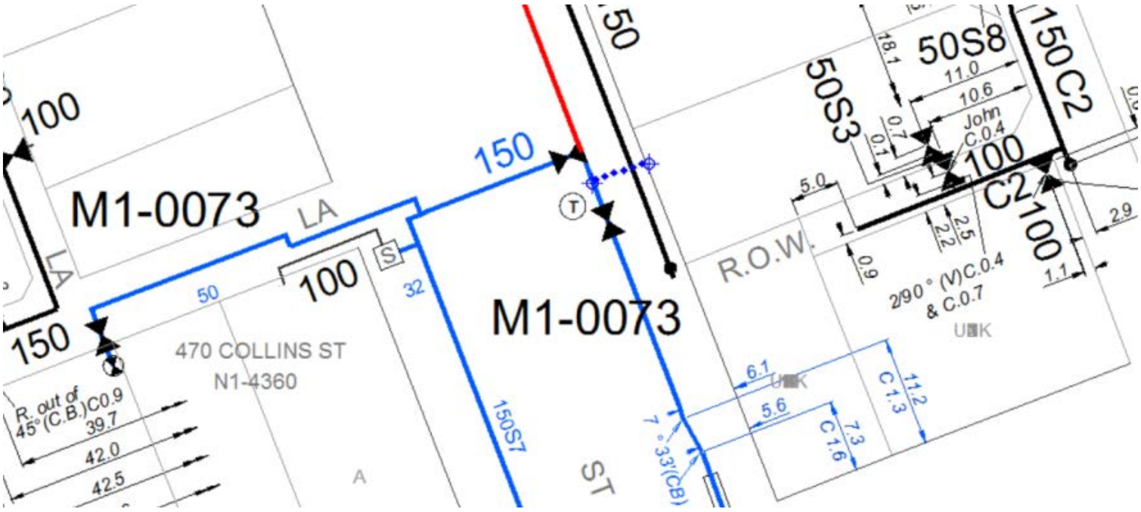
(i) Operating and maintenance procedures.

For guidance for the spacing of mainline valves, see Table 4.6.4.

Appendix C Isolation Valve Locations

TCHP-LV01-Wiliams St, Melbourne 3000

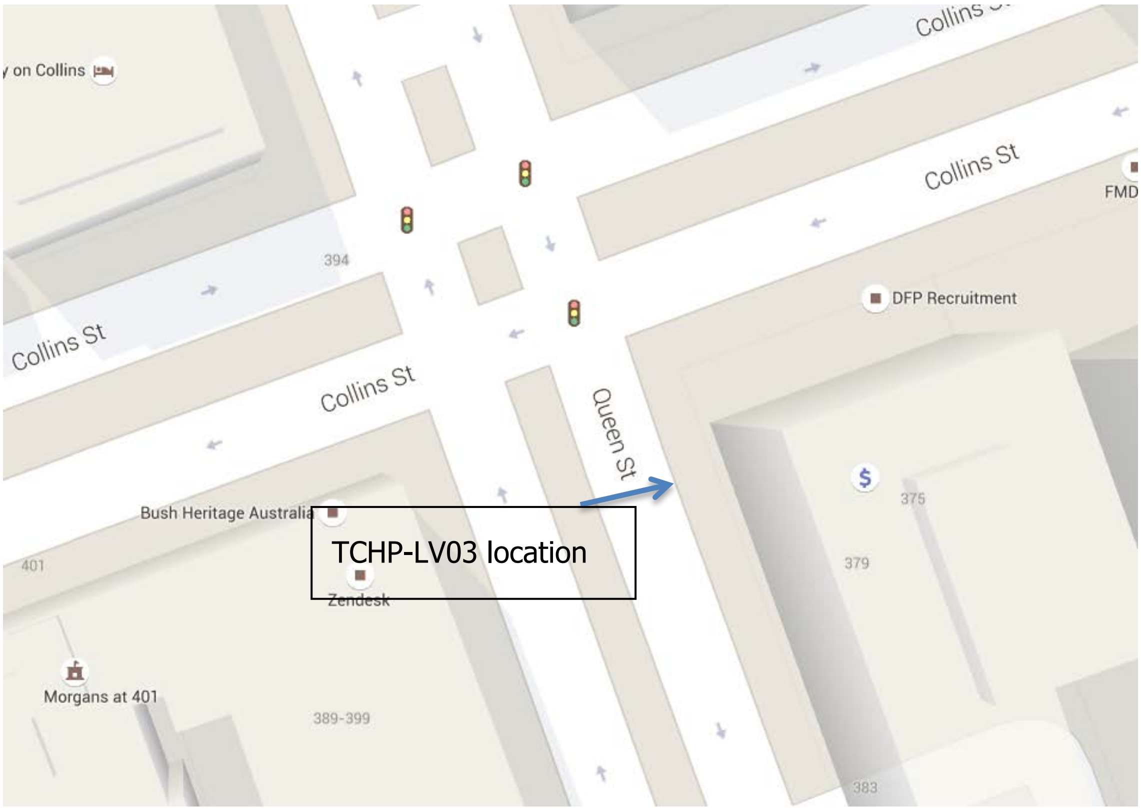




TCHP-LV01 Estimate Details

[redacted]

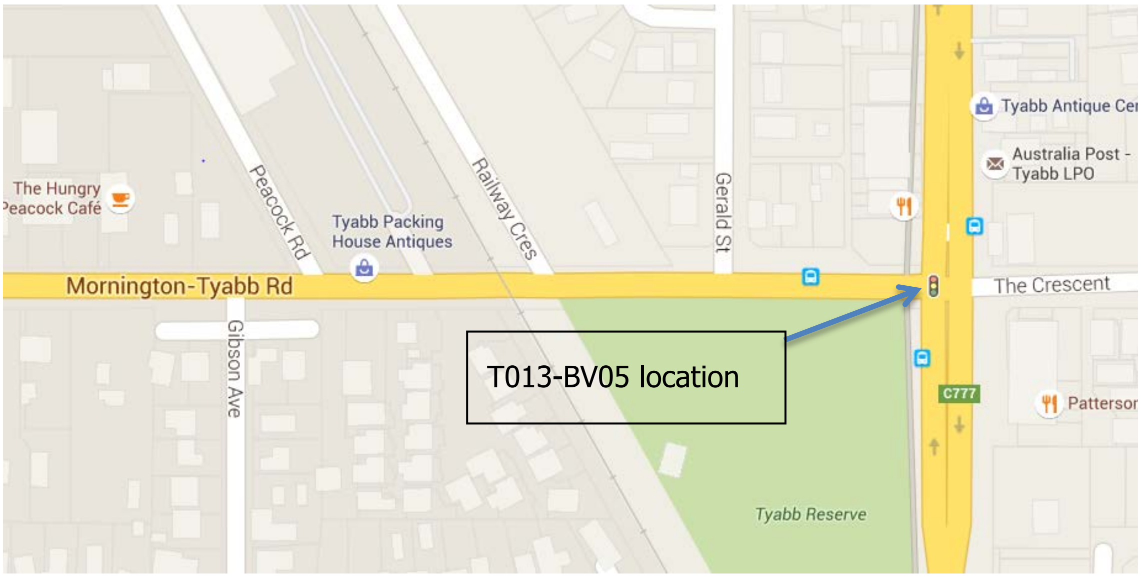
TCHP-LV03-Queens St, Melbourne 3000

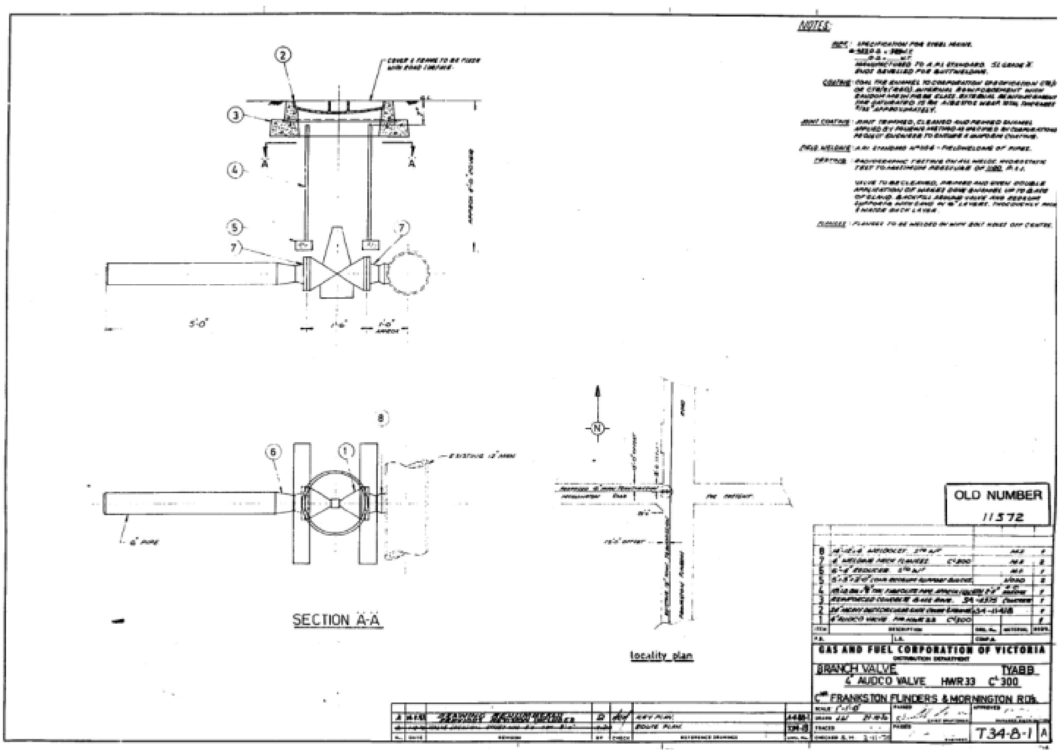


TCHP-LV03 Estimate Details

[redacted]

T013-BV05 Mornington-Tyabb Rd, Mornington 3931

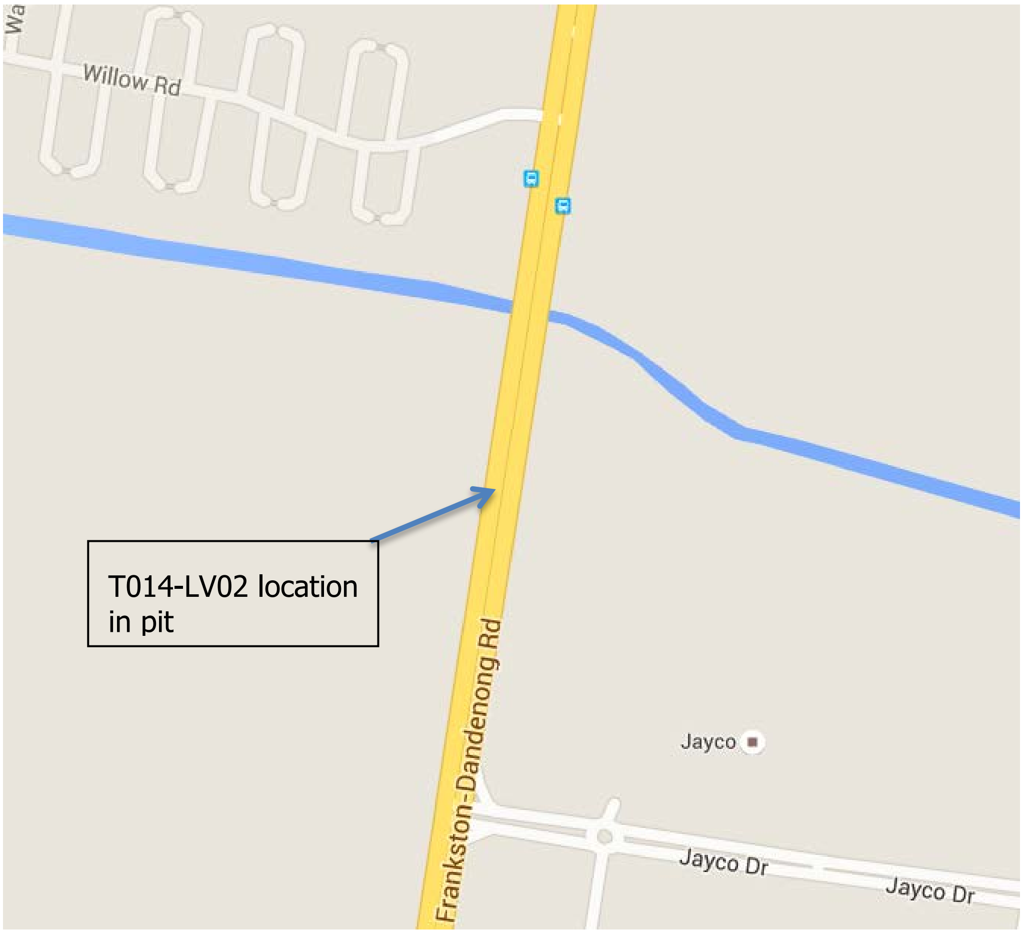


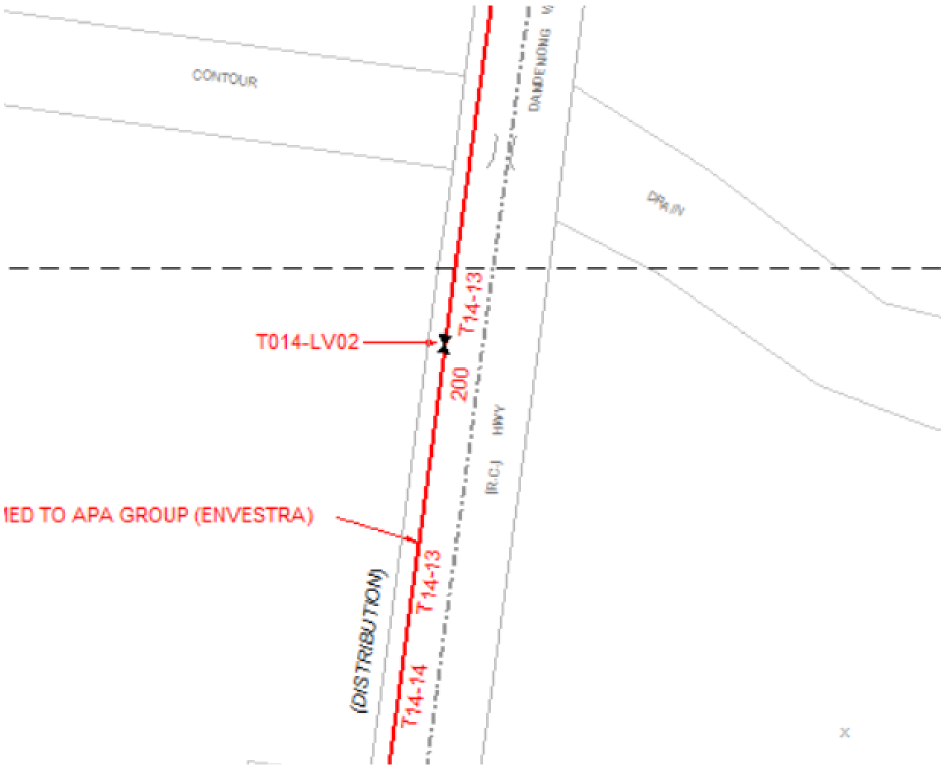

NOTES:
SECTION A-A
locality plan
OLD NUMBER
11572
GAS AND FUEL CORPORATION OF VICTORIA
BRANCH VALVE
TYABB
4" AUDCO VALVE HWR 33 C^L 300
C^NR FRANKSTON FLINDERS & MORNINGTON RDS.
T34-8-1
A

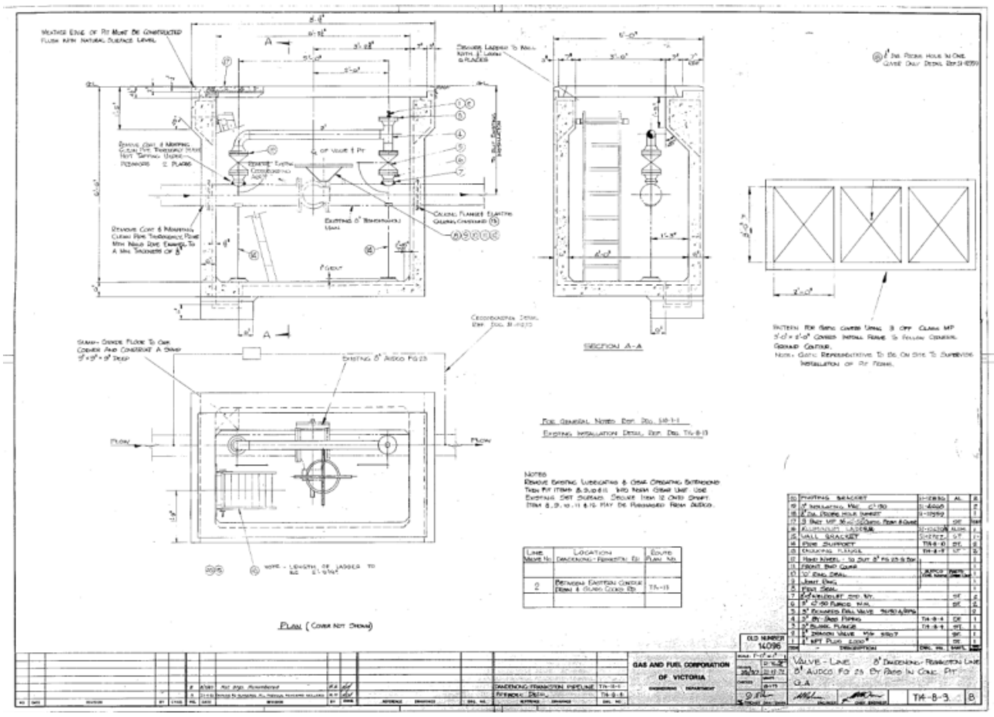
T013-BV05 Estimate Details:

[redacted]

T014-LV02 Frankston-Dandenong Rd, 3175






SECTION A-A
PLAN (COVER NOT SHOWN)
GAS AND FUEL CORPORATION OF VICTORIA
OLD NUMBER 14096
TH-8-3

T014-LV02 Estimate Details:

[redacted]

Business Case – Capex V62

Bushfire Preparedness

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	Roberto Ferrari, *Manager Capital Projects*
Approved By	Andrew Foley, *General Manager Victorian Networks*

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	The primary driver for this project is the risk that Australian Gas Networks Limited's (AGN) Victorian and Albury distribution systems may contribute to property damage and/or personal injury and/or fatality in the event of a bushfire if any of the components of a meter set are damaged and cause an uncontrolled gas release.
Options Considered	The following options have been identified to reduce the risks posed by the two distribution systems in the event of a bushfire: 1 Option 1: Do nothing 2 Option 2: Install Thermal Safety Devices (TSDs) in all new services and retrofit in existing services upstream of the meter control valve in bushfire prone areas[1]. 3 Option 3: Install TSDs in all new services upstream of the meter control valve and retrofit in existing services downstream of the meter control valve in bushfire prone areas. Option 3 is consistent with the option AGN proposed for the South Australian network, which was recently approved by the AER.[2]
Proposed Solution	Option 3 has been selected because it is the most cost effective way to reduce the risk across the network to as low as reasonably practicable and achieves a reasonable balance between residual risk and cost, consistent with Australian Standard AS4645.
Estimated Cost	The forecast capital expenditure (capex) over the next (2018-2022) Access Arrangement (AA) period is $2,947 ($000, $2016).

Consistency with the National Gas Rules (NGR)	The installation of the TSDs complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because:
	• 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)); and
	• it is justified under rule 79(2)(c) as it is required to:
	  • maintain and improve the safety of services (79(2)(c)(i)); and
	  • maintain the integrity of services (79(2)(c)(ii)).

1 Note: The term 'bushfire prone areas' in this business case refers to the areas within the Extreme Fire Zone boundaries as determined by the Country Fire Authority of Victoria.

2 AER, Final Decision: South Australian Access Arrangement 2016-2021, Attachment 6 – Capital Expenditure, May 2016, p. 6-41

Stakeholder Engagement	AGN has undertaken a comprehensive engagement program to better understand the values of our stakeholders. During this engagement, stakeholders told us that they valued initiatives that improve the safety of our network and were supportive of investments that minimise fire risk. Installing TSDs, which results in gas supply being shut off in the instance of a fire, increasing the safety of nearby people and property, is consistent with these customer insights, with 92% of workshop participants indicating support for AGN fitting the devices to reduce the risk of fire. During the stakeholder engagement workshops, workshop participants revealed a perception that bushfire risk in Victoria and Albury has been increasing over time.

1.3. Background

Victoria has had a long history of damaging bushfires. This includes devastating bushfire events such as the Black Saturday Bushfires in 2009, which killed 173 people and burned more than 2000 properties, with several towns left unrecognisable. Every year, the affected areas include communities within AGN's distribution area. The Black Saturday Bushfires in particular, occurred in the eastern part of Victoria and damaged some of AGN's assets, predominantly in Narre Warren. The majority of network assets affected by the fires were consumer installation meter control valves, regulators, meters and associated fittings.

These assets are not designed to withstand the intense heat generated by bushfires and as a consequence uncontrolled gas escapes may occur, which can ignite and/or add fuel to existing fires, increasing the radiant heat on nearby properties. Such situations can arise even after the main fire front has passed. The hazardous conditions created expose gas emergency crews and emergency services personnel to significant risk when attempting to conduct site assessments and/or to excavate mains or services to facilitate shutting off gas supply in the event meter control valves have been destroyed by fire.

Following the Victorian Bushfire Royal Commission, AGN considered it prudent to gain an understanding of potential future risk and evaluate options for risk mitigation through the installation of Thermal Safety Devices (TSDs) in each service inlet in bushfire prone areas. In this regard, the Country Fire Authority (CFA) provided valuable data to AGN from the Victorian Fire Risk Register (VFRR) in respect to extreme fire prone areas within Victoria.

A TSD is a passive thermal device for protection of combustible gas pipes and fittings in extreme heat situations such as bushfires. The device prevents the escape of gas from a gas service when its temperature reaches 100°Celsius. The TSD has an external steel body and an internal heat-sensitive valve, which shuts off the gas supply at this temperature. Its heat resistance characteristics make it suitable for high temperatures generated by bushfires.

In the last AA review for the 2013-2017 AA period, AGN proposed to fit the TSD on the inlet side (upstream) of the meter control valve to prevent any uncontrolled gas escape in the event that the meter control valve, regulator, meter and associated fittings were damaged by fire. This proposal was not accepted by the AER:

> *"The AER does not consider that Envestra has adequately demonstrated the need to retrofit these devices to all gas services in bushfire prone areas. In reaching this conclusion the AER considered the absence of specific legislative requirements to either install thermal safety devices in new installations or to retro fit to existing installations and the absence of specific recommendations from the Victorian Bushfire Royal Commission. Further the AER has no evidence retrofitting these thermal safety devices reflects accepted good industry practice."*[3]

[3] AER Access Arrangement Draft Decision, Envestra Ltd, 2013-17, Part 2 Attachments, p. 134.

The AER has, however, recently accepted a similar proposal by AGN for the AA period 2016/17 – 2021/22 for its South Australian networks to install TSDs using a different installation configuration, which makes it more economical.[4]

This business case considers applying the same technical specifications as those approved for the South Australian network and presents an alternative to the one submitted by the Victorian business five years ago. While this proposal doesn't alleviate the risks to the same level as the prior proposal, it is not as expensive and achieves a reasonable balance between the required expenditure and the risk mitigation.

More particularly, this business case considers the fitting of the TSD downstream of the meter control valve. By doing this, the retrofitting of TSDs will not require excavation and squeezing off an underground section of polyethylene service pipe or, in the case of a steel service, excavating at the gas main in the street and shutting off gas at the service tee. This alternative will imply a simpler and quicker TSD fitting process and, as a consequence, a lower cost due to the reduced labour.

Additionally, this business case considers the fitting of a TSD as a requirement for all new services constructed in bushfire prone areas.

In terms of the views of our customers, taking action to address the risk of bushfires is considered consistent with the findings from our stakeholder engagement program in which 94% of workshop participants indicated support for AGN fitting TSDs in order to reduce the risk of fire. Customers demonstrated greater levels of support for installing TSDs to all new and replacement meters in all areas (63%), rather than the reduced scope of installing TSDs to new and replacement meters in bushfire prone areas only (31%).

As Deloitte comments, customers:

> *"… showed support (63%) for a rolling installation of safety devices to all new and replacement meters in all areas (as well as in bushfire areas). This sentiment was expressed consistently across the workshops, however more strongly in the regional areas (76%) than the metropolitan locations (50%)."*[5]

It is estimated that approximately 20,600 properties are located in bushfire prone areas within AGN's distribution area. The term 'bushfire prone area' is used in this context to refer to the area within the Extreme Fire Zone boundaries as determined by the Country Fire Authority of Victoria. Appendix C shows the Extreme Fire Zones in the Melbourne metropolitan area.

[4] AER, Final Decision: South Australian Access Arrangement 2016-2021, Attachment 6 – Capital Expenditure, May 2016, p. 6-41.
[5] Deloitte, "*Customer Insights Report*", July 2016, pg. 22.

1.4. Risk Assessment

If TSDs are not installed in bushfire prone areas, the existing risks and consequences resulting from uncontrolled gas escapes occurring in the event of a bushfire will continue. These risks range from Moderate to High as highlighted in Table 1.3, which sets out the untreated risks associated with this project. The highest risk categories are:

- *Health and Safety* – Due to the potential exposure of AGN employees or contractors, firefighters and residents to intense radiant heat of a fire during gas shut off operations under emergency conditions, and the potential for the distribution system to contribute to the fires, which may give rise to additional personal injury, fatalities and/or property damage;
- *Environmental* – due to devastating nature of the fires and their effect on flora and fauna; and
- *Reputational* – given the significant attention that bushfires attract from the general public every year and the community reaction that may be generated if AGN assets are seen as contributing to fire damage.

Further detail on the risk assessment is provided in Appendix A to the Business Case.

Table 1.3: Risk Rating

Risk Area	Untreated Risk Level
Health and Safety	High
Environment	High
Operational	Negligible
Customers	Moderate
Reputation	High
Compliance	High
Financial	Moderate
Untreated Risk Rating	**High**

1.5. Options Considered

AGN has identified the following options to deal with the risks posed by the Victorian distribution system in bushfire prone areas:

1. Option 1: Do nothing;
2. Option 2: Install TSDs in all new services and retrofit in existing services upstream of the meter control valve in bushfire prone areas.
3. Option 3: Install TSDs in all new services upstream of the meter control valve and retrofit in existing services downstream of the meter control valve in bushfire prone areas.

The second of these options is equivalent to the option that AGN proposed in the last Victorian AA reviews, while the third option is equivalent to the option that the AER approved for South Australia.

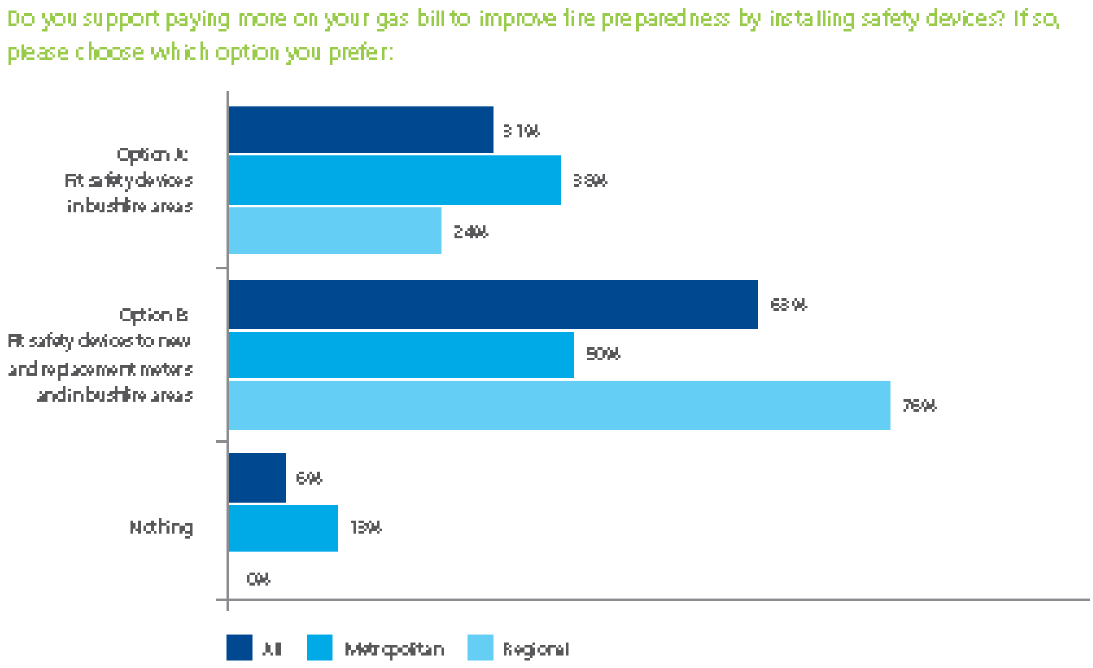
Further detail on these options is provided below.

In terms of the findings from our stakeholder engagement program, AGN presented three options to workshop participants regarding the potential installation of TSDs:

- *Option A* – Fit TSDs to services in bushfire prone areas at a cost of $0.50 per annum on the average customer's bill.
- *Option B* – Fit TSDs to all new and replacement services across the Victorian distribution network, at a cost of $3.60 per annum on the average customer's bill.
- *Option C* – Do nothing at a cost of $0 per annum on the average customer's bill.

The results of this testing is detailed in Figure 1.1 below.

Figure 1.1: Total Workshop Support for Fire Preparedness by Investment Option[6]



1.5.1. Option 1 – Do Nothing

The first option AGN has identified is to do nothing. If this option is chosen, no action will be taken to address the potential for uncontrolled gas releases due to bushfires damaging gas infrastructure. Meter control valves vary in design, specification and age, and many of their components are not designed to withstand the high temperatures generated by a bushfire. As a consequence, they could be damaged during a fire and generate a gas escape and ignite, increasing the radiant heat and aggravating the fire conditions. In addition, if the meter control valve is damaged by the fire, it is likely that shutoff operations to control the gas escape will demand additional effort and time.

6 Deloitte, "*Customer Insights Report*", May 2016, pg. 23. Provided as Attachment 5.7 to our Access Arrangement Information document.

1.5.1.1. Cost/Benefit Analysis

The benefit of this option is that it does not give rise to any upfront costs. It will, however, mean that residents and properties in bushfire prone areas, AGN employees, contractors and firefighters will be exposed to a greater risk of injury, fatality and property damage in the event of a bushfire, which could result in significant compensation claims if AGN is found to be liable in any way. In addition, potential gas releases during a bushfire will make an incremental contribution to damage to residential housing and also to environmental damage, especially to the local flora and fauna.

AGN also notes that this option received little support in the customer workshops held as part of AGN's stakeholder engagement program, with only 6% of workshop participants supportive of this option. More particularly, none of the regional customers who participated in these workshops supported this option.

1.5.2. Option 2 – Install TSDs to all new and existing service connections in bushfire prone areas upstream of the meter control valve

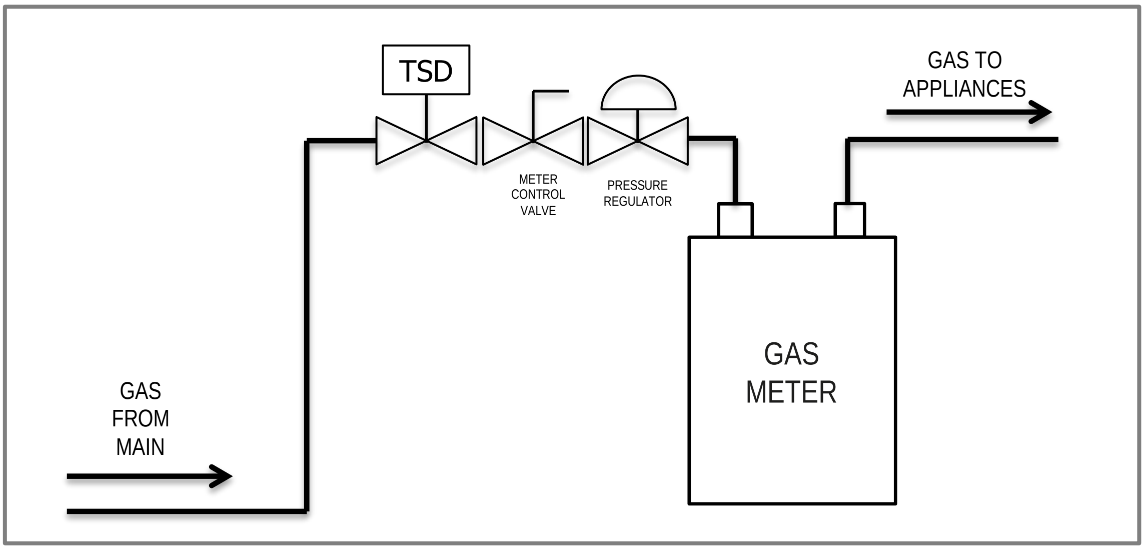
As proposed five years ago, this option consists of the installation of TSDs to all new services and the retrofitting of TSDs to existing services in bushfire prone areas. The installation of the TSD in each service connection will be such that it maximises the protection against an uncontrolled gas release due to damage to the meter set components in the event of fire. This configuration is shown in Figure 1.2, which illustrates that any gas release from damage caused to the meter control valve, pressure regulator or meter will be prevented by the TSD installed upstream of all components in the meter set.

However, retrofitting the TSDs under this configuration requires the interruption of the gas supply between the gas main and the inlet of the meter control valve. This work, as a consequence, entails excavation work to squeeze off the polyethylene service pipe or, in the case of a steel service, excavating at the gas main in the street and shutting off gas at the service tee.

It is, as noted in section 1.3 estimated that approximately 20,600 properties are located in bushfire prone areas within AGN's distribution area. It is proposed to retrofit TSDs to all of these meters within the next AA period taking into account that bushfire events occur almost every summer within AGN's licensed areas. With a planned replacement evenly distributed across the five years of the AA period, the resulting volume for retrofitting of TSDs is 4,120 per year. Also, assuming an annual growth of 1.7%[7] in these areas, an additional 340 new services with TSDs per year will be installed, making a total of volume 22,300.

[7] This growth rate is consistent with the independent forecasts developed for AGN by Core Energy.

Figure 1.2: Configuration for Option 2



The above annual volume of valves to be installed is considerably more than the proposed South Australian annual volume (approximately 1,900), however the ability to deliver this additional volume has been discussed with the changeover contractor, who has confirmed that they will be able to mobilise the additional resources required to meet this volume.

1.5.1.2. Cost/Benefit Analysis

This option provides the best technical solution as it ensures the interruption of the gas flow to any component in the meter set that could be damaged by a fire, including the meter control valve, the pressure regulator or the gas meter. In terms of risk, the improvement in risk reduction is significant when compared to the Do Nothing option and marginally better than Option 3.

The costs of implementing this option are however substantially higher than the cost of the other options because it requires excavation of the service to retrofit the TSD. Specifically, this option is estimated to cost $8,665 ($000, 2016), for the installation of 22,300 TSDs.

This cost estimate is based on similar assumptions to those that were submitted to the AER five years ago for the current AA period; however, material and labour costs have been updated. Volumes have also been updated with the latest available information from the Victorian Government about bushfire prone areas and existing customers in such areas.

The cost estimate assumes the use of a two-man crew to retrofit TSDs in existing services as excavation work will be required. Also, the use of a Supervisor was included in the cost for site work planning, coordination and overall project management. Finally, Compliance and Technical support costs were included as this would be a new activity for the operational teams, which will require the development of work procedures and the inclusion in the technical audit program to ensure compliance with requirements.

For new services, the only cost that needs to be taken into account is the cost of the TSD, because the addition of this component is not expected to increase the service laying times significantly.

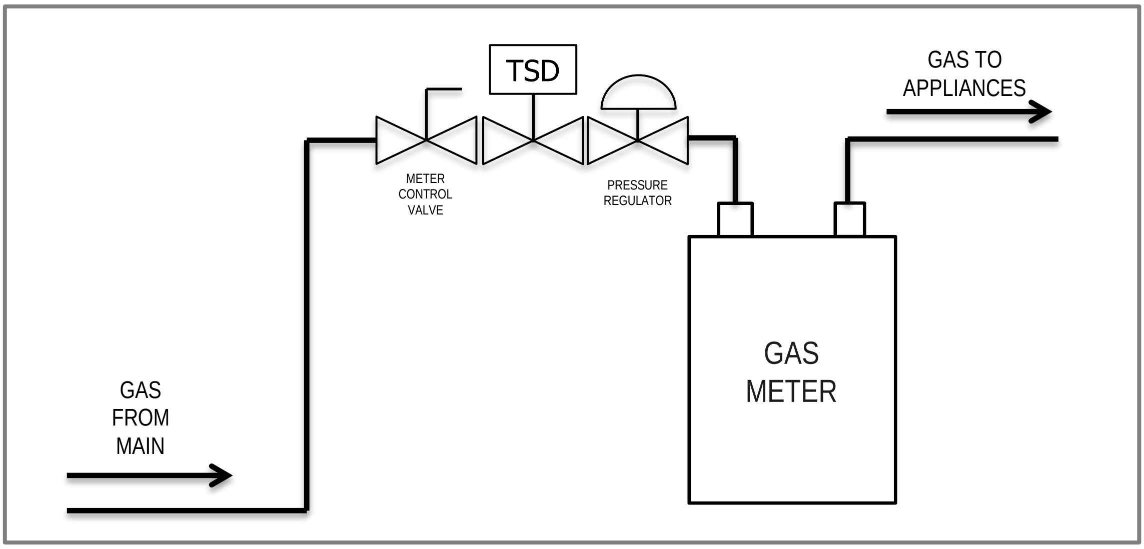
Further detail on the cost estimate for Option 2 can be found in Appendix B.

1.5.3. Option 3 – Install TSDs to all new and existing service connections in bushfire prone areas downstream of the meter control valve

The third option that AGN has identified has similar effects to Option 2 presented above with a slight difference in the configuration. As shown in Figure 1.3 below, Option 3 involves installing the TSD downstream of the meter control valve. Under this configuration, TSDs can be retrofitted by closing the meter control valve and disassembling the meter set. As a consequence, isolation of the service pipe from the main in the street is not required. This means that, rather than the use of a two-man crew with excavating equipment, this work can be completed by a single gas fitter with the use of hand tools.

The only drawback of this option is the fact that the TSD will not prevent an uncontrolled gas release due to damage to the meter control valve. Meter control valves normally have bodies that could withstand high temperatures. However, they can still leak through the stem hole in their bodies if the internal seals are damaged, as it has been seen in actual fire situations. In any case, a leak as described above is expected to be of a relatively small magnitude given the minimal gap between the stem and the stem hole.

Figure 1.3: Configuration for Option 3



The simpler retrofitting means that this option has a significantly lower cost when compared to Option 2, while achieving only slightly higher levels of residual risk.

It is still proposed to use the configuration presented for Option 2 for new services, as there is no benefit in installing the TSD downstream, given that the TSD can be fitted upstream of the meter control valve for only the cost of the TSD itself.

Similar to Option 2, the changeover contractor has confirmed that they will be able to mobilise the additional resources required to meet the proposed volume.

1.5.3.1. Cost/Benefit Analysis

The residual risk for this option is considered slightly higher than that assessed for Option 2 but it is significantly lower than the risk associated with the Do Nothing option. While this option does not offer the same level of safety in the case of a bushfire as Option 2, it still improves the current situation significantly and would prevent uncontrolled gas fires due to damage in most of the meter set components. The fact that the meter control valve would be installed upstream of the TSD means it would not be fully protected by it. However, as mentioned above, the only risk that would remain untreated would be that of a leak through the valve stem opening. The simpler and quicker installation, on the other hand, makes this the preferred option due to the significant reduction in retrofitting costs and the marginal difference in residual risk levels.

Implementing this option is expected to cost $2,947 ($000, 2016), for installing 22,300 TSDs. This estimate is lower than Option 2 because less labour and materials will be required to retrofit the TSD downstream of the meter control valve. Specifically, the cost estimate for retrofits assumes the use of a gas fitter and a similar rate used for a meter refix in normal hours and updated material costs. As with Option 2, the assumed volumes have been updated with the latest available information from the Victorian Government about bushfire prone areas and existing customers in such areas.

Further detail on the cost estimate for Option 3 can be found in Appendix B and section 1.7.4.

1.6. Summary of Cost/Benefit Analysis

The table below provides a summary of the costs, risks and benefits associated with the three options.

Table 1.4: Summary of Cost/Benefit Analysis

Option	Benefits	Costs/Risks
Option 1	Avoids upfront capex of $2.9m to $8.7m	While there are no upfront costs associated with this project, the health and safety and environmental risks associated with this option are High because there is still a continuing risk that the distribution system will contribute to extended damage and/or personal injury in the event of a bush fire.
Option 2	Reduces health and safety, environmental, financial and reputational risks from High to Moderate in the event of a fire.	$8,665 ($000, 2016)
Option 3	Reduces health and safety, environmental, financial and reputational risks from High to Moderate in the event of a fire. While the protection provided by this option in the event of a fire is not as great as Option 2, as explained in section 1.5.3, it provides a similar level of risk reduction as Option 2, with significantly lower costs.	$2,947 ($000, 2016)

1.7. Proposed Solution

1.7.1. What is the Proposed Solution?

AGN proposes to carry out Option 3.

1.7.2. Why are we Proposing this Solution?

Option 3 has been selected because it is the most cost effective way to reduce the risk across the network in a manner that achieves a reasonable balance between residual risk and cost, consistent with Australian Standard AS4645. The adoption of this option is also in keeping with the option that the AER recently approved for the South Australian network, which is more cost-effective than Option 2.

After consideration of the above options analysis, and the results from the stakeholder engagement process detailed below, AGN is proposing to install TSDs to all new and replacement meters in bushfire prone areas only. AGN believes that this proposal achieves an appropriate balance between managing both risk and cost, with the focus being on the areas within its distribution network with the highest risks associated with the propagation of uncontrolled fires.

1.7.3. Stakeholder Engagement

Our customers told us that they value initiatives that improve the safety of our network. Additionally, feedback received in customer workshops indicated that there was strong support for an initiative such as this, with 94% of participants supportive of the installation of TSDs[8]. This result can be broken down further, as detailed below:

- 31% of workshop participants supported the installation of TSDs to all new and replacement meters in bushfire prone areas only; while
- 63% of workshop participants supported the wider installation of TSDs to all new and replacement meters throughout the Victorian network.
- Workshop participants also revealed a perception that bushfire risk in Victoria has been increasing over time.

1.7.4. Forecast Cost Breakdown

The table below provides a summary of the capex that is forecast to be incurred in the next AA period for Option 3, which has been estimated on the basis of the following assumptions:

- *Materials* - The cost of the TSD is based on the quoted price provided by the supplier of the valves that are being installed in the South Australian network. In the case of existing installations, provision has also been made for the cost of an additional fitting to obtain alignment at the meter outlet.
- *Labour* - The labour costs have been based on a simple average of the Meter Refix service rate across the Victorian regions of the gas fitting services contract that has been established through a competitive tender. Provision has also been made for supervision, project management and compliance related activities by APA, although the cost of these direct labour activities is assumed to decrease over time.
- *Forecast volumes* - The number of existing services in bushfire prone areas was obtained by overlaying the bushfire prone area map obtained from the Country Fire Authority of Victoria with AGN's network map. This resulted in an estimate of 20,600 existing services. Provision has also been made for new services, which have been estimated to grow at a rate of 1.7% of existing services. This resulted in an estimate of 1,700 new services over the next AA period. The annual volumes were determined with the objective of retrofitting TSDs to all existing

[8] Deloitte, "*Customer Insights Report*", May 2016, pg. 23. Provided as Attachment 5.7 to our Access Arrangement Information document.

meter in bushfire prone areas within the next AA period. The basis of this proposal is that it is likely that bushfires will occur every year and, as a consequence, there is some urgency in completing the whole program in a relatively short period. The resulting annual work volume under this criterion is considered appropriate with current contractual arrangements and achievable from an operational point of view, and the changeover contractor has confirmed that he will be able to mobilise additional resources to deliver this volume.

A more detailed cost breakdown can be found in Appendix B.

Table 1.5: Project Cost Estimate ($000, 2016)

	2018	2019	2020	2021	2022	Total
New connections						
Volume	340	340	340	340	340	**1,700**
Unit Cost	$12	$12	$12	$12	$12	
Existing connections						
Volume	4120	4120	4120	4120	4120	**20,600**
Unit Cost	$153	$145	$140	$136	$136	
Total Cost	**$636**	**$600**	**$582**	**$564**	**$564**	**$2,947**

Table 1.6: Project Cost Estimate, by cost ($000, 2016)

	2018	2019	2020	2021	2022	Total
Materials	$90	$54	$36	$18	$18	**$215**
Direct Labour	$120	$120	$120	$120	$120	**$600**
Contracted Labour	$426	$426	$426	$426	$426	**$2,132**
Total Cost	**$636**	**$600**	**$582**	**$564**	**$564**	**$2,947**

1.7.5. Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN considers the forecast capex for this project to be:

- *Prudent* – The expenditure is necessary in order to maintain and improve the safety of services to customers and the public by ensuring that gas does not flow unimpeded in a bush fire, and that protection of life and property is maximised. The expenditure is therefore of a nature that would be incurred by a prudent service provider.
- *Efficient* – The work has been spread across a period of years to ensure the program can be managed and supervised in an efficient and controlled manner with estimated labour rates based on current contractor tendered rates. The proposed expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.

- *Consistent with accepted good industry practice* – Identifying and reducing risks to as low as reasonably practicable is consistent with good industry practice and is reflected in Australian Standard AS4645 (Gas Distribution Networks).
- *Achieves the lowest sustainable cost of delivering pipeline services* – Reducing risk to as low as reasonably practicable in a manner that effectively balances costs and risks in this case is consistent with the objective of achieving the lowest sustainable cost given the scale of the liability claims that could be made if the distribution network contributes to extended damage and/or personal injury in the event of a fire.

The capex can therefore be viewed as being consistent with rule 79(1)(a) of the NGR.

The proposed capex is also consistent with rule 79(1)(b), because the expenditure is necessary to:

- maintain and improve the safety of services (rule 79(2)(c)(i)) to provide a means to shut gas of in the extremely hazardous conditions of a bushfire; and
- maintain the integrity of services (rule 79(2)(c)(ii)), which include maintaining the security of supply. By providing a means of isolating the service pipe from the fire, gas supply can be restored more quickly than if there is no TSD present.

Appendix A Risk Assessment

The top panel in the table below sets out the results of the risk assessment assuming the TSDs are not installed, while the bottom panel sets out the residual risks if Option 3 is implemented in the manner described in this business case. The Asset Management Plan provides further information on APA's risk assessment framework.

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels
Risk Untreated Option 1	**Likelihood**	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	***High***
	Consequence	*Significant*	*Significant*	*Minor*	*Medium*	*Significant*	*Medium*	*Medium*	
	Risk Level	*High*	*High*	*Low*	*Moderate*	*High*	*Moderate*	*Moderate*	
Residual Risk Option 2	**Likelihood**	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	***Moderate***
	Consequence	*Significant*	*Significant*	*Minor*	*Medium*	*Significant*	*Medium*	*Medium*	
	Risk Level	*Moderate*	*Moderate*	*Negligible*	*Low*	*Moderate*	*Low*	*Low*	
Residual Risk Option 3	**Likelihood**	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	***Moderate***
	Consequence	*Significant*	*Significant*	*Minor*	*Medium*	*Significant*	*Medium*	*Medium*	
	Risk Level	*Moderate*	*Moderate*	*Negligible*	*Low*	*Moderate*	*Low*	*Low*	

Appendix B Cost Estimates

The table below provides further detail on the cost of implementing Option 2 ($2016).

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]								
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]								
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

*Numbers in the table may not sum due to rounding

**Includes motor vehicle

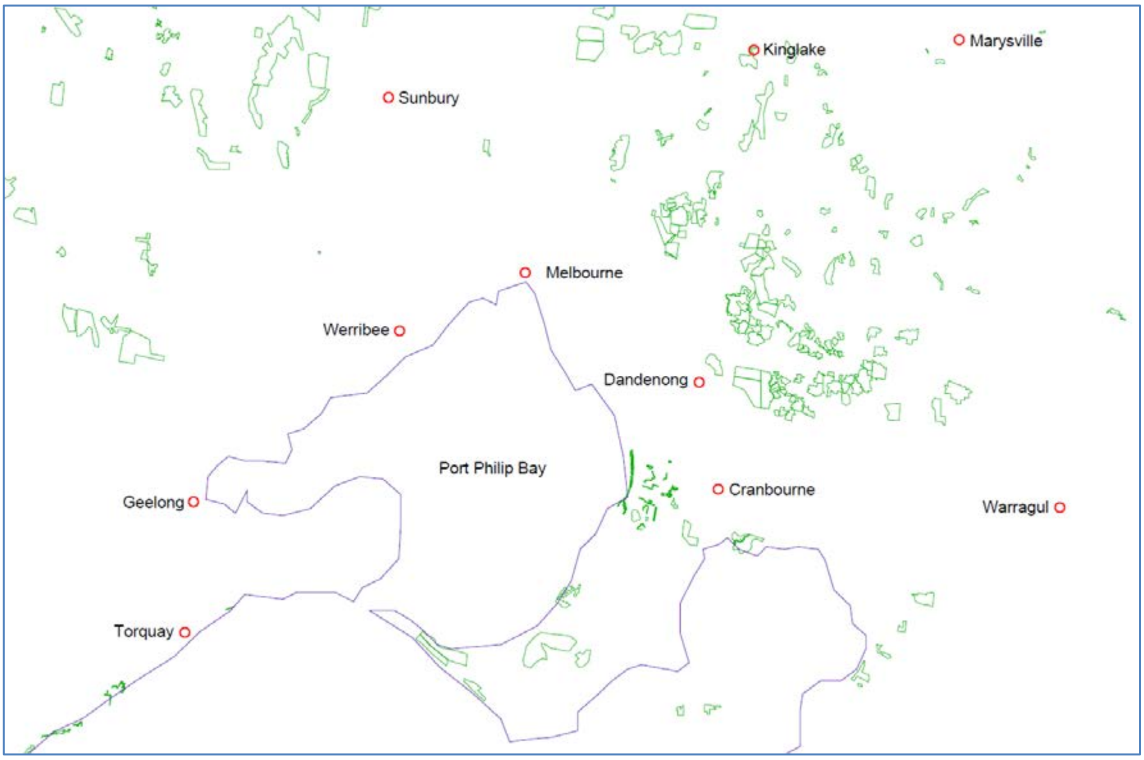
The table below provides further detail on the cost of implementing Option 3 ($2016).

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]								
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]								
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

*Numbers in the table may not sum due to rounding

**Includes motor vehicle

Appendix C Extreme Fire Zones, Melbourne Metropolitan Area



Business Case – Capex V79

I&C Meter Set Refurbishment Program

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	James Rudolph, *Field Maintenance Manager*, APA Group
Approved By	Andrew Foley, *General Manager Victorian Networks*, APA Group

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	Australian Gas Networks Limited's (AGN's) Victorian & Albury network has approximately 3,250 industrial and commercial (I&C) meter sets, typically consisting of large regulators, filters, pilots and valves, connecting pipework and the meter itself. While the meters on these sets are changed on a 10-year basis, the meter assembly remains in place, with some installations over 40 years old. The external condition at many I&C meter sets is now reaching a level where touch up painting is no longer sufficient to effectively maintain these meters. This is because the bulk of the protective paint has deteriorated to such an extent that corrosion of meter assembly pipe works, regulators, valves and fittings is becoming a problem. Approximately 1,950 of these I&C meter sets (out of the 3,250) have been identified as potentially requiring re-painting or replacement over the next 15-20 years. This number is based on the estimated number of large outdoor meter sets (delivering minimum 40scm/hr).
Options Considered	The following options have been considered to address the risks posed by the degradation of the I&C meter sets: • Option 1: No refurbishment program, continue current practices to apply touch-up paint where required and replace components and meter sets when they fail. • Option 2: Implement a program to comprehensively recoat I&C meter sets at 732 (refer Group One on page 3) locations of the 1,950 assessed as presenting the highest risk during the next Access Arrangement (AA) period. Continue or expand the program beyond 2022 to treat the remaining locations and any additional ones identified in the intervening period. • Option 3: Replace the piping and components at I&C meter sets identified as highest risk with all new assemblies (approximately 325 units in total). • Option 4: Implement a program to recoat I&C meter sets at 651 locations and replace 81 I&C meter sets with all new assemblies (refer Group One on page 3) totaling 732 sites.
Proposed Solution	Option 2 is the preferred solution because it is the most cost effective way of managing the risks associated with the corrosion of I&C meter sets.
Estimated Cost	Option 2 is estimated to cost $3,820 ($000, 2016) in capital expenditure (capex) over the next AA period. Further capex is anticipated in future AA periods to complete the program.

Consistency with the National Gas Rules (NGR)	The refurbishment of I&C meter sets complies with the new capex criteria in rule 79 of the National Gas Rules (NGR) because:
	• 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)); and
	• it is justified under rule 79(2)(c) as it is required to:
	  • maintain and improve the safety of services (79(2)(c)(i));
	  • maintain the integrity of services (79(2)(c)(ii)); and
	  • comply with a regulatory obligation or requirement (rule 79(2)(c)(iii)).

Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Reliability and Safety themes as its implementation will allow AGN to maintain the safety of the network whilst continuing to provide a highly reliable supply of natural gas to our customers by establishing a comprehensive meter set repainting program to effectively manage the risk of a failure due to corrosion. More information detailing the results of the stakeholder engagement program is provided in Chapter 5 of the Access Arrangement Information document.
Supporting Information	• V79 Supporting Information 1 (NPV and Options Analysis 25yr)

1.3. Background

The Victorian network has approximately 3,250 I&C meter sets, typically consisting of large regulators, filters, pilots and Over Pressure Shut Off (OPSO) valves, connecting pipework and the meter itself. While the meters on these sets are changed on a 10-year basis, the meter assembly remains in place, with some installations over 40 years old.

The preventative maintenance for these larger meter assemblies involves mechanical and instrumentation checks on a 6 monthly or 12 monthly basis. These checks include testing the pressure settings are correct, that regulators lock-up, and that over pressure protection devices function correctly. All joints and fittings are leak tested using a leak test fluid and pipework and components are visually inspected for damage and corrosion. Paint on steel components serves as the main protection against corrosion, and as such, the condition of paintwork is also checked during preventative maintenance activities to identify areas where paint is no longer protecting the steel surface of components.

Where necessary, local areas of peeling or de-laminated paint are removed (ground back) and the area is repainted. This work is conducted by internal operations staff during usual maintenance activities. The paint touch-up process has generally maintained the coating in a fit for purpose state. However, the external condition at many I&C meter sets is now reaching a level where touch up painting is no longer sufficient to effectively maintain corrosion protection coating. This is because the bulk of the protective paint has deteriorated to such an extent that corrosion of meter assembly pipe works, regulators, valves and fittings is becoming a problem. Significant corrosion has been observed on a number of meter sets, as highlighted in the regulator top cover shown in Figure 1.1 and the pipework in Figure 1.2. The uneven paint surface also visible in the picture indicates past touch-up painting has been performed.

Figure 1.1: Corrosion on Regulator Body Cap, I&C Meter Set

Figure 1.2: Delaminating Paint & Corrosion on I&C Meter Set Pipework

To address the safety and integrity of service related risks posed by corrosion, the meters will either need to be replaced or be subject to on-site grit blasting and extensive repainting[1] of the pipework, regulator and valve bodies.

Approximately 1952 sites have been identified as potentially requiring re-painting or replacement over the next 15-20 years. This number is based on the estimated number of large outdoor meter sets (delivering minimum 40scm/hr). This total has then been divided into four groups, based on the following assumptions:

- Group One: 732 meter sets assessed as highest risk meter sets, typically older or located in corrosive environments.
- Group Two: 610 meter sets assessed as moderate to high risk, typically similar location and age to Group 1 meters, but in better condition.
- Group Three: 488 meter sets assessed as moderate risk, typically newer installations, located in less corrosive environments.
- Group Four: 122 meter sets, assessed as moderate to low risk, typically new or near new units.

[1] More extensive painting consists of completely grit blasting the meter set and reapplying new paint. This work is done by a contractor.

Over the remainder of the current AA period, AGN maintenance staff will collect information on I&C meter sets located outdoors in the course of their usual duties. This information will be used to assess the condition of these meter sets to better facilitate prioritising the work according to the risk as outlined above.

A similar meter set repainting program has recently been approved by the AER in relation to AGN's South Australian network.[2]

1.4. Risk Assessment

A risk assessment has been carried out using AGN's established evaluation criteria, with the untreated risk associated with corrosion of I&C meter sets assessed as "Moderate".

Further detail on the risk assessment can be found in Appendix A.

Table 1.3: Risk Rating

Risk Area	Untreated Risk Level
Health and Safety	Moderate
Environment	Negligible
Operational	Moderate
Customers	Low
Reputation	Low
Compliance	Moderate
Financial	Negligible
Untreated Risk Rating	**Moderate**

The key health and safety related risk posed by the corroded meter sets is that the corrosion leads to gas leaks and/or component failure (e.g. a regulator cap leaks, valve sealing issues). AGN staff, contractors, and members of the public may be exposed to a hazardous gas environment in the event of a failure.

Failure of an I&C meter set component or pipework is also an operational risk, where failure results in the interruption of supply to customers. As I&C meter sets typically supply a single customer, the volume of customers potentially affected by a single site failure is low, but the impact of a gas outage on the customers supplied (generally businesses), is likely to be significant. While AGN's liability varies depending on contract terms, typically damage to third party equipment or injury to personnel may result in AGN being liable for losses. Loss of supply to an industrial user also has implications if the affected party has recourse to recover lost production costs via their contract. Finally, if a failure is significant, it may be necessary to reduce system pressures or isolate a particular part of the AGN network. This may affect multiple industrial users and potentially thousands of domestic customers.

2 AER, Draft Decision for AGN South Australian Networks Access Arrangement 2016-21, November 2015, Attachment 6 – Capital Expenditure, p. 6-47

Compliance risk arises were AGN is found to be operating in breach of the gas distribution license or applicable Acts. The gas distribution license is issued by the Essential Services Commission, while Energy Safe Victoria is charged with ensuring compliance with the Gas Safety Act 1997. The distribution license invokes a number of Australian Standards including AS4645.1 (2008) Gas Distribution Networks. Section 7 of AS4645.1 requires that all maintenance activities be carried out in compliance with a Formal Safety Assessment, and that

> *"maintenance shall be managed to ensure a safe and adequate gas supply to consumers in an environmentally sound manner"*[3].

The Gas Safety Act also requires that[4]:

> *"a gas company must manage and operate each of its facilities to minimise as far as practicable -*
> *(a) the hazards and risks to the safety of the public and customers arising from gas; and*
> *(b) the hazards and risks of damage to property of the public and customers arising from gas".*

The compliance risk associated with failure to maintain I&C meter sets in accordance with these regulations has been assessed as Moderate due the large population of metersets (i.e. 1952 meters assessed as being in poor condition) and the likely high frequency of occurrence, rather than the severity of the risk.

1.5. Options Considered

AGN has identified the following options to address the risks outlined in section 1.4:

- Option 1: Continue current practices to apply touch-up paint where required and replace I&C components and meter sets if they fail (i.e. no refurbishment).
- Option 2: Implement a program to comprehensively re-paint I&C meter sets located outdoors at 1952 locations over four AA periods. In the next AA period, the work volume would comprise approximately 732 locations, the Group 1 meter sets identified in Section 1.3. As stated above, selection of exactly which meter sets fall into each group would be based on actual condition, in order to ensure the meter sets representing the highest risk are refurbished first. As identified above, this program is likely to continue beyond 2022 to treat the remaining locations and any additional ones identified in the interim.
- Option 3: Replace the piping and refurbish components at 325 I&C meter sets. The volume of work is reduced when compared to Option 2 due to the greater complexity of replacement versus in-situ painting. Based on data collected by maintenance personnel, those meter sets considered high risk will be prioritised for replacement. Based on the estimated time required per meter set for planning and implementation, AGN has the ability to replace a maximum of 325 units over five years. It is expected that this program would continue in future AA periods with a similar volume of work.
- Option 4: Combining elements of Option 2 and Option 3, this option would be structured to repaint the majority of meter sets as per Option 2. Further, where the condition of meter sets is identified as at risk of causing failure, those meter sets would be replaced. The ratio of meter sets requiring replacement versus repainting over the next AA period is assumed to be approximately 1 in 9 based on data recently collected by maintenance staff regarding the condition of meter sets.

[3] AS4645.1 Section 7.1 "Basis of Section".
[4] Gas Safety Act 1997 (Vic) section 32.

1.5.1. Option 1 – Do Nothing (i.e. no refurbishment program)

This option involves the application of touch-up paint where required and the replacement of components and meter sets in the event that components become unserviceable or fail. While touch-up paint will be applied, the paintwork will continue to deteriorate. This deterioration may lead to a loss of supply or gas leaks due to failure of a component, or failure of the pipework.

The life of the external pipe work, valves and fittings can also be expected to be substantially reduced, with an increased likelihood that assets will not realise their design life. Further future repairs are expected to be more expensive than refurbishment costs in the medium to longer term.

1.5.1.1. Cost/Benefit Analysis

Costs

This option incurs the following costs:

- *Refurbishment or replacement on failure* – Failures are expected to occur, and increase in number over time as more and more sites reach the point where normal touch-up painting and planned maintenance is no longer able to control corrosion. If the meter sets that have been identified as being in poor condition are not refurbished (either through repainting or replacement of parts) there is a risk that corrosion activity will cause a gas leak, or component failure and an interruption of supply. Furthermore, components such as valves, filters and regulators may become unfit for service. When failures occur or components are identified as unfit for service, reactive replacement of regulators, valves or meters, and repainting of all meter set pipework, or if necessary replacing the whole meter set installation, would incur costs greater than a planned program of similar works.

  The number of, and increase in, failures used in Option 1 modelling in "V79 Supporting Information 1 (NPV and Options Analysis 25yr)" (refer to tab "Work Volume) is based on the assumption that the frequency of failures in the next AA period will be insignificant, but will begin to increase if no planned remediation work is undertaken in the next period.
- *Life of assets* – The life of the pipe work, valves, filters, regulators and fittings can also be expected to be substantially reduced with future repair or replacement more expensive than refurbishment costs in the medium to longer term.

The NPV analysis considers the capital costs of this option, however any costs to AGN arising from loss of supply to industrial and commercial users in the event of an I&C meter set failure are not included, and may be significant, especially if supply cannot be restored promptly, or in the event that damage to property occurs.

With regards to compliance risks outlined in Section 1.4, this option does not fully address the requirements of AS4647 or the Gas Safety Act to manage assets to minimise the threat to property and the public as far as practicable.

Benefits

The main benefit of this option is deferring the immediate cost of replacing or carrying out a comprehensive grit-blasting and painting program into future AA periods. This approach equates in practice to a reactive "after the event" replacement program rather than a more prudent risk-based preventative maintenance program. Under an "after the event" approach customer outage is unavoidable if the need for coating remediation is not identified early enough to prevent failure or complete replacement of the meter set pipework and components is required.

1.5.2. Option 2 – In Situ Refurbishment of 732 Meter Sets

This option would involve implementing a program to refurbish 732 I&C meter sets identified as the highest risk over the next AA period. The proposed refurbishment program would continue in the following three AA periods in order to re-condition all 1952 meter sets identified above. The volume of work would decrease over the subsequent AA periods until a sustainment level is reached. The table in Figure 3 shows how the proposed program may be implemented and extended over a 50 year period.

The program of work commences as a refurbishment program, to bring meter sets already in service up to standard, and ensure they meet their design life. This also reduces the risks associated with poor condition meter sets as quickly as practicable given the available resources. Focusing on treating the Group 1 meter sets in the next AA period allows an initial focus on the backlog of meter sets requiring refurbishment, and provides a basis for the development of a sustainable program over future AA periods. A sustainable program will ensure capacity is available to refurbish new meter sets installed due to organic growth as they age. These new meter sets will require refurbishment 25 to 30 years after commissioning.

Following the initial four AA periods (20 years), all existing meter sets will have been refurbished. After this point in time, it can be expected that the paint on those first refurbished will again be starting to deteriorate, and an ongoing sustainment program will be required. The volume of work for a sustainment program will be less than in the initial AA periods, as shown in Figure 1.3 below.

Figure 1.3: Proposed Refurbishment Program with Ongoing Sustainment Option (Number of sites)

	AAP Start Year										
	2018	2023	2028	2033	2038	2043	2048	2053	2058	2063	2068
Group 1	732			122	122	122	122	122	122	122	122
Group 2		610			122	122	122	122	122		122
Group 3			488			122	122	122	122		122
Group 4				122			61	61			
	732	610	488	244	244	366	427	427	366	122	366
	Refubishment phase										
				Sustainment phase							

Prior to the next AA period, I&C meter sets will be assessed and prioritised in order to maximise risk reduction.

1.5.2.1. Cost/Benefit Analysis

Costs

The capital cost to grit blast, prepare and repaint I&C meter sets in situ is estimated to be $4,979 ($2016) per set. This cost includes internal labour and contractor costs. The costs for contract blasting and painting services have been estimated using current contract rates, which have been established through a competitive tender. In addition, for each year of the program the cost for a dedicated project manager for 12 weeks has been included to plan the expected volume of work, at a cost of $35 ($000, 2016) per year. The proposed program over the next AA period is therefore projected to cost a total of $3,820 ($000, 2016) in capex.

Benefits

This option effectively mitigates the risks associated with old, corroded and deteriorated paint work and, in so doing, reduces the residual risk to Low (see Appendix A). In reducing the risk to low, this option demonstrates a practical approach to managing the condition of I&C Meter sets to reduce the risk of failure, and therefore meets the requirements of AS4645 and the Gas Safety Act. Further, taking preventative action by refurbishing high risk meter sets in the next AA period will limit the occurrence of failures requiring full replacement, therefore avoiding significant capital expense in future periods.

At the completion of the refurbishment phase of proposed work (approximately 2033) the paint condition of the majority of outdoor meter sets greater than 40scm/hr size will be in good condition. As a result, in future AA periods (2033 onwards), the number of meter sets requiring repainting will be reduced, as shown in Figure 1.3 above, delivering capital expenditure savings.

1.5.3. Option 3 – Replace I&C Meter Sets

This option involves the full replacement of meter sets where coating has deteriorated significantly. Replacing meter sets costs more than refurbishing them, due to new materials and increased labour.

Based on the estimate that each meter set to be replaced will require up to three days of project management time, in addition to a project planning phase of 12 weeks, the maximum work volume per year is 81 units. This volume would require significant external labour to be employed to fabricate and install the replacement meter sets.

Using the maximum unit per year estimate, over the next AA period this option would aim to replace 325 meter sets, or an average of 65 meter sets per year[5]. The units to be replaced would be selected from the Group 1 I&C meter sets (see Section 1.3 above). As with Option 2, further data on the condition of meter sets will be collected prior to the commencement of the next AA period, and this will be used to determine the priority of meter set replacements.

With no repainting program, it is likely that as meter sets age their coatings will deteriorate, resulting in the need to replace meter sets in the future. This program will therefore need to be repeated in future AA periods with a similar volume of work. In order to provide a conservative comparison with Option 2, the proposed program of replacing 325 meter sets over five years has been continued in future AA periods in the NPV analysis.

1.5.3.1. Cost/Benefit Analysis

Costs

The average capital cost to build and install a new meter set is $24,603 ($2016). This includes labour for an internal project manager, supervisor and fitter for each site to be replaced, and contract resources to fabricate the meter set and assist with installation. In addition, to manage the volume of work and establish the replacement program, the cost of a separate project manager has been added, at $35 ($000, 2016) in the first year, reducing to $23.5 ($000, 2016) in years 2-5. The cost of replacing 325 meter sets in the next AA period is estimated to cost $8,125 ($000, 2016) in capex.

Benefits

This option mitigates the risks associated with old and deteriorated paint work where meter sets are replaced. However, because the number of meters that would be replaced is lower than the number of meters that would be refurbished under Option 2, this option is less effective at mitigating the risks identified in Section 1.4). In only partially reducing the risks associated with

[5] 325 meter sets to be refurbished over five years, starting with 49 in year 1, reaching a maximum of 81 sets per year in the second and third years of the Access Arrangement Period. This allows for project ramp up in the initial year, and leaves capacity in the final year to account for unforeseen delays.

failure of I&C meter sets, this option may not meet the requirements of AS4645 and the Gas Safety Act to reduce the risks as far as practicable.

1.5.4. Option 4 – Mixed Repaint and Replace Program

This option combines elements of Option 2 and Option 3 and, in so doing, aims to mitigate the risks associated with paint deterioration and aged components in I&C meter sets. This option would be structured to repaint the majority of meter sets as per Option 2. Further, where the condition of meter sets is identified as at risk of causing failure, those meter sets would be replaced.

The volume of work is aligned with that in Option 2, with all Group 1 meter sets refurbished or replaced in the next AA period, and half of the Group 2 meter sets. Of the 732 meter sets to be refurbished, approximately 81 would be replaced, while the remainder (651) would be repainted in situ. These volumes are considered achievable using dedicated internal resources and using contractor labour for painting, construction and installation where appropriate. The ratio of meter sets to be replaced versus repainted is a conservative estimate based on the currently available information on condition of meter sets. As with the options above, data on the condition of meter sets will be collected prior to the commencement of the next AA period, and this will be used to better determine the priorities for replacement and repainting.

1.5.4.1. Cost/Benefit Analysis

Costs

This cost of this option includes a dedicated project management resource and internal labour for both painting and replacing meter sets. Contractor costs have been estimated using current contract rates, which have been established through a competitive tender. The cost of this repaint and replace program over the next AA period is estimated to be $5,429 ($000, 2016) in capex.

Benefits

This option effectively mitigates the risks associated with old, corroded and deteriorated paint work and reduces residual risk to Low (see Appendix A). In reducing the risk to low, this option satisfies the requirements of AS4645 and the Gas Safety Act to reduce the risk of damage to property and personnel as far as practicable.

At the completion of the current cycle of proposed work (approximately 2033) the paint condition of the majority of outdoor meter sets greater than 40scm/hr size will be in good condition. As a result, in future AA periods (2033 onwards), the number of meter sets requiring repainting will be reduced, as shown in Figure 1.3 above, delivering capital expenditure savings.

1.6. Summary of Cost/Benefit Analysis

The table below provides a summary of the costs, benefits and risks associated with each of the options.

Table 1.4: Summary of Cost/Benefit Analysis

Option	Benefits	Costs/Risks
Option 1	No capex cost over next AA period Increasing risk of failure resulting in high replacement and repair cost.	Total capex cost over next five AA periods $19,923 ($000, 2016) Increasing risk of corrosion, resulting in a gas leak, component failure or supply interruption, which could result in AGN having to make Guaranteed Service Level (GSL) payments and incurring relighting costs. These costs have not been taken into account.
Option 2	Initially high workload, slowly reducing to a sustainment level by fifth AA period. Reduces residual risk to low.	Total capex cost over five AA periods of $12,419 ($000, 2016), Capex cost over next AA period $3,820 ($000, 2016)
Option 3	Full replacement of 325 I&C meter sets every 5 years over the period. Reduces residual risk to moderate	Total capex cost over five AA periods of $40,624 ($000, 2016), Capex cost over next AA period $8,125 ($000, 2016)
Option 4	Replacement of 81 meter sets in each AA period, and repainting of the remainder. Reduces residual risk to low.	Total capex cost over five AA periods of $27,320 ($000, 2016), Capex cost over next AA period $5,429 ($000, 2016)

To compare the options outlined, AGN has compared the present value of the costs associated with each option. This analysis has been conducted over five AA periods (25 years) in order to capture the time that it is assumed to refurbish all 1952 I&C meter sets identified in Section 1.3. The longer period also shows the reduction in work volumes in future AA periods and allows the operational costs, and associated savings (which occur several years after the capex) to be captured for comparison. The results of this analysis are set out in Table 1.5.

Before looking at this table, it is worth noting that while operational costs and estimated costs for replacing units for Option 1 have been included in the cost benefit analysis, it is not considered a feasible option given both:

- the risks associated with corrosion; and
- the requirement in Australian Standards AS4645 and AS2885, and the Gas Safety Act that risks be managed to as low as reasonably practicable.

Option 1 has not therefore been included in the NPV analysis summary table below.

Further, as noted in Section 1.5.1, the costs associated with any loss of supply to an I&C customer in the event of a meter set failure are not included in the NPV analysis. These costs are difficult to estimate given the range of consumers and activities in which gas is used, however if a meter set fails and supply cannot be restored promptly, AGN's liability could be significant.

Table 1.5: Comparison of Options ($000, 2016)

	NPV 2016	Next AA Period 2018	2019	2020	2021	2022	Subsequent AA Periods 2023 - 2042	Total
Option 2	-9,209	-588	-762	-946	-762	-762	**-8,599**	**-12,419**
Option 3	-27,899	-1,241	-2,016	-2,016	-1,623	-1,229	**-32,499**	**-40,624**
Option 4	-19,080	-818	-1,358	-1,358	-1,076	-818	**-21,891**	**-27,320**
Discount Rate (real pre-tax WACC)	**3.14%**							

As the results in Table 1.5 show, Option 2 is the most cost effective of the feasible options over the 25 year period considered.

1.7. Proposed Solution

1.7.1. What is the Proposed Solution?

AGN proposes to carry out Option 2, which will involve repainting all 1,950 meter sets of 40 scm/hr and greater that are located outdoors. This program of work will be implemented over five AA periods, with more than half the meter sets to be repainted in the first two AA periods to target the oldest and highest risk meter sets, with work reducing to a sustainment level over the following periods.

1.7.2. Why are we Proposing this Solution?

Option 2 is being proposed because it is the most cost effective way of managing the risks associated with I&C meter sets. Put another way, it provides the best risk reduction for the least capex over the 25 year period assessed, as highlighted by the NPV analysis presented above. This option addresses the hazard presented by the highest risk I&C meter sets currently in service (Group 1) and a significant proportion of the second highest risk group (Group 2). Further, by forward loading the repainting work in the first two AA periods this option reduces the work required in future AA periods, and makes a sustainment program more achievable at the completion of this program. Finally, this option meets requirements in the Gas Safety Act, Gas Distribution Code and Australian Standard 4645 to manage facilities to minimise as far as practicable the hazards associated with gas and gas installations.

1.7.3. Forecast Cost Breakdown

The forecast cost of carrying out Option over the next AA period 2 is set out in Table 1.6. This forecast was determined using the volume breakdown presented, based on a distribution of the total number of sites to be treated, spread over several AA periods, as detailed in Appendix C.

Table 1.6: Project Cost Estimate ($000, 2016)

	2018	2019	2020	2021	2022	Total
Volume / yr	111	146	183	146	146	732
Average Capital Cost / site	$5.29	$5.22	$5.17	$5.22	$5.22	$5.22
Total ($000, 2016)	**$587**	**$762**	**$946**	**$762**	**$762**	**$3,820**

Note: Numbers may not total due to rounding. Average costs vary over the AA period because of the inclusion of fixed costs.

Forecast volume

The volume of work was determined based on the following assumptions:

- 3250 meter sets >40 scm/hr or maintained by Systems Operations (I&C meter sets)
- 1952 meter sets (60% of 3250) estimated to be in open air enclosures/locations.
- Of the 1952, four groups of meters, based on condition, as outlined in Section 1.3.
- Repainted meter sets do not require touch up paint for 5 to 10 years.
- Repainted meter sets will need to be repainted again after 25 years.

Labour

Using the proposed program phasing outlined in Appendix C, the cost for each year of the proposed program was determined. Each meter set to be repainted was estimated to require one day of project management, an internal supervisor for one day, and an internal fitter's labour for one day. In addition to the internal labour costs, painting and grit blasting services will be provided by an approved contractor. The cost of this service is based on similar recently completed work, and existing contract prices. The average cost per unit to repaint an I&C meter set in situ is $4.979 ($000, 2016).

In addition to the average cost per meter set, the cost of a dedicated project manager utilised for 12 weeks each year ($35.1 ($000, 2016)) is included, to plan and deliver the volume of work associated with this option. This cost is spread across the number of units to be painted each year, and accounts for the difference in average cost per unit over the next AA period, as shown in Table 1.6.

It is estimated that the average time on site for APA and contractor labour to carry out the refurbishment is ½ to 1 day (refer to Appendix B), or 6-12 days per month for an average of 12 units / month. On this basis the target of an average of 146 refurbishments per year is seen as readily achievable.

Timing of the work

Table 1.6 outlines the volume of work and cost estimate over the next AA period. The phasing is such that there is a gradual increase in work volume over the first three years of the AA period as the program becomes established. The decline towards the end of the AA period is to allow for increased volume if routine maintenance work over the balance of the current AA period and into the next AA period identifies more high priority meter sets than is currently estimated.

1.7.4. Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN considers the forecast capex for this project to be:

- *Prudent* – This expenditure is necessary in order to maintain the safety and integrity of services because unchecked corrosion activity could lead to gas leaks and/or component failure resulting in the interruption of gas supply. The expenditure is therefore of a nature that a prudent service provider would incur. The options analysis outlined above, also shows that AGN has selected the least cost feasible option.
- *Efficient* – Without the proposed expenditure the external pipe work valves and fittings can be expected to further deteriorate and corrode, reducing the life of these assets and/or making future repairs more expensive. When coupled with the fact that Option 2 is the most cost effective feasible option and will be carried out in the least cost manner by using a combination of internal and external resources, the proposed expenditure can be considered consistent with what a prudent service provider acting efficiently would incur.
- *Consistent with accepted good industry practice* – It is good industry practice to identify risks and take action to address those risks, and to ensure that assets undergo refurbishment when required to extend asset life. Addressing the corrosion related risks associated with the meter sets is also consistent with the requirement in Australian Standards AS4645 that risks be managed to as low as reasonably practicable and in a manner that balances costs and risks.
- *Achieves the lowest sustainable cost of delivering pipeline services* – The proposed project is necessary to maximise the life of the I&C meter sets that have been identified as being in poor condition. Without the proposed expenditure the external pipe work valves and fittings would further deteriorate and corrode, reducing the life of these assets and making future repairs more expensive. In the long term, the costs of not undertaking the proposed project would be considerably greater. The proposed expenditure is therefore consistent with the objective of achieving the lowest sustainable cost of delivering pipeline services.

The capex can therefore be viewed as being consistent with rule 79(1)(a) of the NGR.

The proposed capex is also consistent with rule 79(1)(b), because the expenditure is necessary to:

- *maintain and improve the safety of services (rule 79(2)(c)(i))* - safety is improved by reducing the likelihood of an I&C meter set failing and releasing gas which presents a hazard to AGN operational staff, the consumer's staff, members of the public and property of the consumer or public.
- *maintain the integrity of services (rule 79(2)(c)(ii))* - the proposal to re-paint assets in degraded condition is a direct action to maintain the integrity of pipework and components in I&C meter sets, to prevent degradation or failure as a result of corrosion due to exposure to the elements.
- *comply with a regulatory obligation or requirement (rule 79(2)(c)(iii))* – the proposed repainting of I&C meter sets complies specifically the requirements of AS4645.1 Section 7.1 – that: " Maintenance shall be managed to ensure a safe and adequate gas supply to consumers in an environmentally sound manner"[6], and the Gas Safety Act 1997[7] Part 3, Div 1, s32 which states that:

[6] AS4645.1 Section 7.1 "Basis of Section".
[7] Gas Safety Act 1997 (Vic) section 32.

"a gas company must manage and operate each of its facilities to minimise as far as practicable -
(a) the hazards and risks to the safety of the public and customers arising from gas; and
(b) the hazards and risks of damage to property of the public and customers arising from gas".

Appendix A Risk Assessment

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Option Risk
Risk Untreated	Likelihood	*Possible*	*Rare*	*Possible*	*Unlikely*	*Unlikely*	*Possible*	*Possible*	MODERATE
	Consequence	*Medium*	*Minor*	*Medium*	*Minor*	*Minor*	*Medium*	*Insignificant*	
	Risk Level	*Moderate*	*Negligible*	*Moderate*	*Low*	*Low*	*Moderate*	*Negligible*	
Residual Risk Option 1	Likelihood	*Possible*	*Rare*	*Possible*	*Unlikely*	*Unlikely*	*Possible*	*Possible*	MODERATE
	Consequence	*Medium*	*Minor*	*Medium*	*Minor*	*Minor*	*Medium*	*Insignificant*	
	Risk Level	*Moderate*	*Negligible*	*Moderate*	*Low*	*Low*	*Moderate*	*Negligible*	
Residual Risk Option 2	Likelihood	*Rare*	*Rare*	*Rare*	*Unlikely*	*Unlikely*	*Rare*	*Unlikely*	LOW
	Consequence	*Medium*	*Minor*	*Medium*	*Minor*	*Minor*	*Medium*	*Insignificant*	
	Risk Level	*Low*	*Negligible*	*Low*	*Low*	*Low*	*Low*	*Negligible*	
Residual Risk Option 3	Likelihood	*Rare*	*Rare*	*Possible*	*Unlikely*	*Unlikely*	*Rare*	*Possible*	Moderate
	Consequence	*Medium*	*Minor*	*Medium*	*Minor*	*Minor*	*Medium*	*Insignificant*	
	Risk Level	*Lowe*	*Negligible*	*Moderate*	*Low*	*Low*	*Low*	*Negligible*	
Residual Risk Option 4	Likelihood	*Rare*	*Rare*	*Rare*	*Unlikely*	*Unlikely*	*Rare*	*Unlikely*	LOW
	Consequence	*Medium*	*Minor*	*Medium*	*Minor*	*Minor*	*Medium*	*Insignificant*	
	Risk Level	*Low*	*Negligible*	*Low*	*Low*	*Low*	*Low*	*Negligible*	

Appendix B Detailed Cost Breakdown

[redacted]

[redacted]

Business Case – Capex V83

Transmission Pipeline Modification for In-Line Inspections

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	Matthew Read, *Integrity Engineer*
Approved By	Andrew Foley, *General Manager Victorian Networks*

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	The majority of Australian Gas Networks Limited's (AGN) Victorian Networks transmission pipelines were constructed to various outdated standards, legislation and technology, and are not configured to accommodate In-Line Inspection (ILI) tools.[1] Without the ability to undertake ILI, the structural integrity of pipelines can only be demonstrated as compliant with Australian Standard (AS) 2885.3-2012 (Pipelines – Gas and Liquid Petroleum: Operations and Maintenance) by conducting excavations and direct inspections. These excavations are typically at locations where there is evidence that the pipeline coating has disbonded. Some pipelines are installed with vintage coatings which are showing increasing signs of degradation, and increasing the likelihood of corrosion defects developing, potentially leading to pipeline failure, thus making it increasingly difficult to demonstrate pipeline structural integrity in accordance with AS 2885.3-2012. To reduce the risks associated with the safety and integrity of services provided by these pipelines, AGN has been investigating the options for modifying the pipelines so they can be inspected by ILI. ILI inspections have a high probability of detecting steel defects within a high degree of accuracy along the pipeline length. This is required to demonstrate the integrity of pipelines and ensure the health and safety of the public in the vicinity of the pipeline. By having detailed knowledge about each pipeline's condition, AGN will be able to put in place targeted and effective measures to ensure the security of supply to customers. AGN has identified two pipelines; Dandenong to Frankston and North Melbourne to Fairfield, both of which were constructed with vintage coatings and are now showing signs of significantly increasing coating degradation. The Dandenong to Frankston pipeline, which is 24 kilometres (km) in length, is used to supply approximately 45,000 customers, while the North Melbourne to Fairfield pipeline is 11 km in length and used to supply 50,000 customers. If these pipelines are allowed to degrade, then it could lead to a significant gas escape and loss of supply to the customers supplied by these pipelines.
Options Considered	The following options have been considered to identify the issues identified with these two highest risk pipelines: • Option 1: Do nothing. Continue direct examination excavations on coating defect sites nominated as mandatory to excavate by APA policy.

[1] In-Line Inspection (ILI) tools are propelled internally down the pipeline by flowing fluid and examine the internal dimensions and condition of the pipe wall, to identify defects that may require attention.

Proposed Solution	• Option 2: Commence a program to inspect and modify the two pipelines to accommodate ILI tools. • Option 3: Commence a program to recoat accessible sections of the two pipelines. • Option 4: Increase the number of direct examination excavations to include 50% of coating defect sites nominated as "candidate" sites under APA policy. Option 2 is proposed because it is the most cost effective way to monitor the risks associated with deteriorating pipeline coatings on the Dandenong to Frankston and North Melbourne to Fairfield pipelines.
Estimated Cost	Option 2 is estimated to cost $13,951 ($000, $2016) over the next Access Arrangement (AA) period, of which $7,986 ($000, $2016) is expected to be spent on the Dandenong to Frankston Pipeline and $5,965 ($000, $2016) on the North Melbourne to Fairfield pipeline. Of the above cost, $13,622 is capital expenditure (capex), and $329 is operating expenditure (opex).
Opex Step Change	The opex of $329 ($000, 2016) does not require a step change in base year opex, as it replaces the excavations due to DCVG surveys on these pipelines.
Consistency with the National Gas Rules (NGR)	The refurbishment complies with the new capex criteria in rule 79 of the National Gas Rules 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)). The opex component also satisfies rule 94 because 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.
Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Reliability and Safety themes as its implementation will allow AGN to maintain the safety of our network whilst continuing to provide a highly reliable supply of natural gas to customers by modifying transmission pipelines, conducting ILI and subsequently excavating and inspecting anomalies discovered. More information detailing the results of the stakeholder engagement program is provided in Chapter 3 of the Access Arrangement Information document.
Supporting Information	• V83 Supporting Information 1: NPV and Options Analysis.

1.3. Background

The Dandenong to Frankston (24.0km) and North Melbourne to Fairfield (11.1km) transmission pipelines were constructed in 1962 and 1971 respectively. The majority of the alignment for these pipelines is located within road reserves that traverse through suburban or industrial areas, which are more sensitive to failure than pipelines located in rural regions. These pipelines convey natural gas for the purpose of distribution to residential and industrial consumers equating to approximately 45,000 customers for the Dandenong to Frankston pipeline and approximately 50,000 customers for the North Melbourne to Fairfield pipeline. A summary of technical details for both pipelines is provided in Appendix A of this business case.

These transmission pipelines are over 40 years old and are now in the second half of their design life. Although different standards, legislation and technology were applied for each pipeline, neither pipeline was constructed to accommodate ILI tools. Both pipelines are coated with Coal Tar Enamel (CTE), which is a vintage coating that is no longer used for new pipeline construction. In both pipelines, the CTE now shows signs of increasing deterioration.

Pipeline coating plays a significant role in preventing corrosion, thereby maintaining structural integrity of a pipeline. In the presence of a deteriorating coating, a pipeline becomes more reliant on Cathodic Protection (CP) to prevent corrosion and growth in corrosion becomes a higher probability.

Action is therefore required to ensure the ongoing safety and integrity of services.

Demonstrating structural integrity of the pipeline is crucial for verifying that the pipeline is safe to operate, and is required for compliance with the current Australian Standard AS2885.3-2012 (Clause 6.5), which states:

> *"The Licensee shall implement processes and procedures to monitor and assess pipe wall integrity to maintain the required wall thickness.*
>
> *To maintain pipe wall integrity, the Licensee shall ensure the following requirements are met:*
>
> > *(a) Sufficient wall thickness shall be maintained at all locations, to contain fluid at the system MAOP. The minimum allowable wall thickness shall be assessed as follows:*
> >
> > *(i) For a new pipeline, and for an in-service pipeline containing no corrosion anomalies or uniform general wall thickness loss, the minimum wall thickness shall be calculated in accordance with AS 2885.1.*
> >
> > *(ii) For a pipeline with anomalies, the minimum wall thickness shall be assessed in accordance with Section 9.*
> >
> > *(b) Sufficient structural integrity shall be maintained at joints to prevent leakage at the MAOP.*
> >
> > *(c) Where the safety management study identifies environment-related cracking, HIC or corrosion fatigue, the pipelines shall be inspected for evidence of both longitudinal and circumferential cracks in accordance with the PIMP.*
> >
> > *(d) The pipeline shall be inspected for evidence of material and construction anomalies in accordance with the PIMP.*
> >
> > *(e) The results of inspections shall be analysed and the outcomes incorporated in the PIMP.*
> >
> > *(f) Corroded pipelines shall be inspected for the extent of internal and external corrosion in accordance with the PIMP and the rate of corrosion shall be determined."*

There are two principle methods for demonstrating structural integrity of a pipeline:

- Indirectly measure the pipeline coating for faults in the CP current and conduct direct examination[2] at identified faults to inspect the pipeline for steel deterioration; or
- Indirectly measure the thickness and condition of the pipeline steel by ILI and verify results by direct examination.

1.3.1. Indirect Measurement of Coating Faults

Indirect measurement of the pipeline coating condition is typically conducted by taking surface measurements of electrical current which escapes through coating faults (Direct Current Voltage Gradient (DCVG) survey). The surface measurement provides an indication of the size of the coating fault, but is dependent on a number of factors, which may lower the relative accuracy of the measurement. Direct examination by excavation is then conducted on a mandatory basis for coating faults of a certain size, with other sites considered candidates for excavation based on the AS 2885.1-2012 Location Classification, CP and previous direct examination history. It is expected that if defects in the steel pipeline wall are present on the pipeline they will be at coating fault locations; however, there is generally little correlation between the size of a coating fault and magnitude of defects in the steel.

Furthermore, factors such as soil type or defect shape may impact accuracy of measurements and lead to a lower probability of detecting faults. There are also sections of pipelines, such as under river or rail crossings and in some sections of road reserve, which cannot be inspected by this method. These types of sections account for approximately 4.7% and 8.5% of the Dandenong to Frankston and North Melbourne to Fairfield pipeline alignments respectively.

Overall, this method only provides a sample of locations where the pipeline steel condition has been assessed, and must be extrapolated for the remaining portion of the pipeline, which has not been inspected or directly examined.

APA policies, developed to ensure compliance with Australian Standards, require mandatory excavations to inspect the condition of the coating and underlying pipe steel when the voltage gradient measured at the ground surface by the DCVG survey is above a threshold value (greater than 15% IR drop[3]). Further, defects between 5% and 15% IR drop must be considered as a site that is a candidate for excavation, assessed using other factors described within the policy. Throughout the rest of this business case, these two categories of defect sites found by DCVG surveys are referred to as "mandatory" and "candidate" sites respectively.

Table 1.3 provides a summary of the results of indirect measurement (DCVG survey) of coating faults for the Dandenong to Frankston and North Melbourne to Fairfield pipelines. Both pipelines have a significantly higher coating fault rate per kilometre than other AGN pipelines in the Victoria and Albury networks.

[2] Direct examination is physically excavating and exposing the pipeline, removing the coating, cleaning the pipeline steel and examining and measuring any defects present. Other inspection methods which do not do this are considered to be indirect examination.

[3] IR Drop (equivalent to voltage drop) is a measure of the voltage gradient measured at the ground surface associated with a coating defect on the buried steel pipeline.

Table 1.3: Summary of Coating Surveys

Pipeline	Coating Survey Year	Coating Faults Detected	Total Coating Fault Sites for Excavation*	Mandatory Coating Fault Sites Excavated**	Comments/Excavation Results Summary
Dandenong to Frankston	1993	101			Coating fault excavation data not available
	2005	167	43	43	Nine instances of corrosion identified, most significant at 17.3% wall thickness loss
	2010	351	93	34	Six instances of corrosion identified, most significant at 15.7% wall thickness loss
North Melbourne to Fairfield	1994	198			Coating fault excavation data not available
	2005	220	77	29	Six instances of corrosion identified, most significant at 4.7% wall thickness loss
	2011	360	165	39	Eight instances of corrosion identified, most significant at 6.3% wall thickness loss

*Total defect sites where the IR drop is > 5%

**Total defect sites where the IR drop is >15%

It can be seen from this table that the total number and severity of the faults are increasing significantly for both pipelines. The total number of coating defect sites of concern (mandatory + candidate) is increasing at a greater rate than the number requiring mandatory excavation. Thus the mandatory sites excavated over time are providing a progressively lower direct assessment sample size of the potential corrosion along the pipelines' length.

1.3.2. In-Line Inspection

ILI involves inserting an intelligent pigging tool into the pipeline, which takes measurements of the pipeline steel condition as it is propelled by natural gas flow through the pipeline. This method has a high probability of detecting steel defects within a high degree of accuracy along the pipeline length. A more effective targeted repair program can then be developed rather than be based on coating faults where there may be no correlation with the type or magnitude of steel defects. This significantly reduces the risk of a pipeline defect degrading to failure point and creating a safety incident or impacting downstream consumers, and provides a better means for demonstrating the pipeline is suitable for continued operation at the end of its design life.

The latest revision of AS2885.3-2012 (Clause 6.6) requires that consideration be given to modifying pipelines to permit inspection by ILI when they are not capable of accommodating an ILI tool.

ILI is considered good industry practice for demonstrating pipeline structural integrity, with the APA Pipeline Management System[4] requiring that all new pipelines greater than or equal to DN150 be designed to accommodate ILI tools. AGN and other pipeline operators have modified existing pipelines to accommodate ILI where they were not originally constructed for these tools, and this type of modification has previously been approved by the Australian Energy Regulator (AER) (refer to Appendix B). These modifications were approved on the basis of maintaining structural integrity and mitigating the safety and reliability risks associated with operating high pressure pipelines. The AER considered that the investment for these modifications to be prudent and consistent with good industry practice.

An AGN pipeline that is currently undergoing modification to accommodate ILI is the Dandenong to Crib Point transmission pipeline. The condition of the Dandenong to Crib Point Pipeline at the time of AER approval[5] is consistent with the Dandenong to Frankston and North Melbourne to Fairfield pipelines.

1.3.3. Pipeline Summary

As shown in Table 1.3, corrosion events have been detected on both the Dandenong to Frankston and North Melbourne to Fairfield pipelines, with these events initiating prior to 2005. It is extremely difficult to determine the rate of growth for corrosion, particularly in the absence of the comprehensive data that can be obtained from ILI. The corrosion growth rate is dependent on a number of localised factors such as soil type and CP levels. These factors are subject to a range of uncertainty and may vary greatly along the length of a pipeline. If an industry standard corrosion growth rate of 0.4mm/year is applied to corrosion events detected from coating faults identified in 2005, it is possible that they may reach failure point within 14 years (i.e. 2019). Given that the number of coating faults and potential corrosion sites is increasing, there is an increased probability that one of these sites will develop into a leak.

Due to the type of coating and the age of these pipelines it is becoming increasingly difficult to demonstrate that the structural integrity of these pipelines complies with the latest revision of AS2885.3-2012 (Clause 6.5). In the absence of being able to conduct ILI on these pipelines, there is increasing relianance on coating fault excavations which only provide a localised view of corrosion at any one point on the pipeline, and only a small statistical sample of the entire pipeline length. Corrosion events can be extremely localised, and in order to develop a broad understanding of corrosion along the whole of the pipelines, a larger number of samples than the coating fault excavations is required.

AGN has also undertaken a comprehensive stakeholder engagement program to better understand the values and needs of our stakeholders and customers. During this engagement, customers told us that they valued initiatives that maintain the reliability and improve the safety of our network. Consistent with this, ensuring that corrosion on major transmission mains is minimised and that the integrity of these pipelines is assured contributes to the provision of a safe supply of natural gas.

Our stakeholder engagement program also found that given the current very high level of gas supply service reliability, understandably, no participants supported investments to deliver a level of reliability beyond what they currently experience. Although participants did not want to invest in improving reliability, they do value the current levels, and are supportive of investment that

4 The Pipeline Management System is a set of engineering documentation, whose content is in accordance with AS 2885, which is a mandatory requirement of AS 2885, and describes how the pipeline is designed, operated and maintained.

5 The business case that the AER approved was V04 Refurbishment of Dandenong to Crib Point Pipeline. See AER, Access Arrangement Final Decision Envestra Ltd, Part 2 Attachments, March 2013, p. 94.

maintains it. During our workshops, participants also told us that they do not want to see an increased level of outages; rather they would like the status quo to continue.

1.4. Risk Assessment

The principal risk in this case is related to a failure of the pipeline as a result of corrosion or deterioration of a pipeline defect. The stress level for these pipelines is such that a propagating rupture is very unlikely; however, a failure of a localised corrosion site could result in a significant gas release. This could potentially impact the safety of residents and industries in close proximity to the pipeline and depending on the location and time of year could result in major leak and disruption of supply industrial and residential consumers.

The overall untreated risk has been rated as 'High' as per APA's Risk Management Policy, which is summarised in Table 1.4 (details in Appendix C) because the health and safety, operational, reputational and financial risks are high.

Table 1.4: Risk Rating

Risk Area	Untreated Risk Level
Health and Safety	Moderate
Environment	Low
Operational	High
Customers	High
Reputation	High
Compliance	Moderate
Financial	High
Untreated Risk Rating	**High**

This project's risk assessment has taken into account:

- risk to health and safety for residents and industries in close proximity to the pipeline alignment from the collection of natural gas from an unidentified leak and subsequent ignition; and
- risk to operational supply to up to approximately 45,000 in the case of the Dandenong to Frankston Pipeline and 50,000 customers in the case of the North Melbourne to Fairfield Pipeline (including major industrial and commercial customers) in the area from a worst case failure event, such as a leak at the start of a pipeline.

1.5. Options Considered

Four options have been identified to mitigate the risks associated with the pipelines that are unable to be inspected by ILI. Hydrostatic testing (as allowed by AS 2885.3) was not considered an option because it would require shut down of the pipeline for a number of weeks and would result in loss of supply to customers supplied by the downstream networks which are fed from these pipelines.

- Option 1: Do nothing. Continue direct examination excavations on coating defect sites nominated as mandatory to excavate by APA policy;
- Option 2: Modify the Dandenong to Frankston and North Melbourne to Fairfield pipelines in the next AA period to accommodate ILI tools;
- Option 3: Recoat the Dandenong to Frankston and North Melbourne to Fairfield pipelines where accessible; and
- Option 4: Conduct additional excavations on the pipelines to include all mandatory and half of candidate sites.

1.5.1. Option 1 – Do Nothing

The first option AGN has identified is to do nothing. Under this option, AGN would continue regular DCVG surveys and subsequent inspection of the pipeline by direct assessment at mandatory coating fault sites. This could continue until either significant corrosion degradation is identified that requires reactive repair at much higher costs than planned works, or a pipeline failure event occurs. Continuing the inspections based on coating fault results and direct assessment following reactive repairs or incidents will not address the risk of subsequent similar events at different locations.

1.5.1.1. Cost/Benefit Analysis

The benefit of this option is that there are no additional upfront capital costs. The sites for mandatory excavation found at each 5-yearly survey would continue to be excavated consistent with current practice. There are, however, a number of additional operational costs and risks associated with this option, including:

- Ongoing operational costs of the pipeline by means of coating inspection and subsequent excavations at mandatory sites of $561 ($000, 2016) and $625 ($000, 2016) for the Dandenong to Frankston and North Melbourne to Fairfield pipelines, respectively for the next five yearly inspection. These costs are initial costs estimated from the number of anticipated coating faults requiring excavation into the future (see below), and the estimated cost of coating fault excavations of $12,750 per site, from the recently approved South Australian business case for the same activity (SA21a). Because of the anticipated increase in coating faults, they are expected to escalate over time.
- As the pipeline coatings continue to deteriorate, it is estimated that mandatory coating fault sites may increase by 10 faults (which is a broad average of the deterioration rate observed across the 2 pipelines, from Table 1.3) for each pipeline for each five yearly coating survey and will subsequently escalate excavation costs.
- A worst case failure event could result in loss of supply to the numbers of customers supplied by the pipeline, at a cost between $15,300 ($000, 2016) or $17,000 ($000, 2016) for the Dandenong to Frankston and North Melbourne to Fairfield pipelines, respectively.[6] A failure event could also result in damage to public property and loss of life. These costs are based on costs of relighting customers fed by these pipelines, and Guaranteed Service Level (GSL) payments for a prolonged supply interruption, which would be the case should a leak develop

[6] These estimates have been calculated using a relight cost of $40 per connection and assuming a Guaranteed Service Level payment of $300 per connection.

which requires shutting down the pipeline for repairs[7]. In a situation where the pipeline failure is not a worst case failure event, it is likely that some customers can be backfed from other networks and this cost would be lower.

- Some sections of pipelines will remain inaccessible for coating inspection and excavations, such as under river or rail crossings and underneath some sections of road pavement or concrete. These types of sections account for approximately 4.7% and 8.5% of the Dandenong to Frankston and North Melbourne to Fairfield pipeline alignments, respectively.
- There is no reduction in risk for this option, as identified in Section 1.4 (refer to Appendix C for risk ranking). The overall risk remains High.
- AGN will have limited means demonstrating continuing pipeline integrity in compliance with the requirement of AS 2885.3-2012 (Clause 6.5), that minimum pipe wall thickness is maintained at all locations, as not all locations can be accessed by the pipeline coating measurement inspection method. Because of this, once the end of pipeline life is reached, it is likely that the pipelines will require replacement.

1.5.2. Option 2 – Modification of Pipelines to Accommodate ILI Tools

The second option AGN has identified is to convert the Dandenong to Frankston and North Melbourne to Fairfield pipelines to be inspected by ILI tools in the next AA period.

This option has two expenditure components, capex and opex. The capex component will entail:

- Engineering investigation and physical proving of pipeline features to determine modifications required for the pipeline to be capable of ILI. This will include physical verification of features such as offtakes and combined bends and will confirm what features need to be modified to accommodate the ILI tool. Each pipeline will require different modifications depending on the current configuration; however, both pipelines will require installation of pig trap risers, pig traps and replacement of line valves while only the Dandenong to Frankston pipeline may require replacement of offtakes and bends.
- Land negotiation, approval and compensation for new temporary or permanent pig launcher and receiver locations.
- Design, procurement and fabrication of new pig launchers and receivers.
- Design, procurement and fabrication of other modifications required to make the pipeline capable of ILI. This includes replacement of line valves for most pipelines, and may include other modifications identified during the engineering investigation.
- Approval by regulatory bodies (i.e Energy Safe Victoria (ESV)) and other stakeholders.
- On-site construction and commissioning.
- Carrying out an ILI inspection run to identify anomalies and defects in the pipe wall.

Once the ILI inspection run is complete on each pipeline, the data is assessed and excavations undertaken at nominated locations to directly examine and repair the anomaly or defect. This expenditure is opex, as it is the same activity as is undertaken at present for locations identified by DCVG surveys.

[7] The Guaranteed Service Level (GSL) payment is intended to ensure that customers are compensated if an energy distribution company does not meet certain minimum performance standards. The amount payable and the conditions under which a GSL payment is triggered are set out in Part E of the Code. For supply interruptions, repeated or lengthy interruptions would incur a GSL of between $150 and $300 per affected customer. Refer ESC website for a copy of the Code: http://www.esc.vic.gov.au/document/energy/26123-gas-distribution-system-code-2/

1.5.2.1. Cost/Benefit Analysis

The costs of making the Dandenong to Frankston and North Melbourne to Fairfield pipelines capable of ILI include the following:

- Costs for engineering investigation and modification of the Dandenong to Frankston pipeline, are estimated at $7,986 ($000, 2016). This includes:
  - subject to the engineering investigation, capex of $7,822 ($000, 2016) for replacement of four line valves, five tees / offtakes, installation of two pig traps as well as conducting the ILI run. and
  - Opex of $164 ($000, 2016) for the validation and repair excavations.
- Costs for engineering investigation and modification of the North Melbourne to Fairfield pipeline, are estimated at $5,965 ($000, 2016). This includes:
  - subject to the engineering investigation capex of $5,800 ($000, 2016) for replacement of three line valves and installation of two pig traps as well as conducting the ILI run, and.
  - Opex of $164 ($000, 2016) for the validation and repair excavations.

It is worth noting that the detailed engineering investigation may identify additional modifications required to make each pipeline capable of accommodating ILI over and above the scoping that has been undertaken for this business case.

The benefits for this option are as follows:

- This option significantly reduces the likelihood of a pipeline failure due to corrosion, and reduces the residual risk to Moderate (refer to Appendix C for details).
- Accurate inspection data for the whole of the pipelines (not just where indicated by coating defects) which clearly shows the location, nature and magnitude of pipe wall thickness loss due to corrosion, or other anomalies such as unidentified construction or subsequent third party defects. Having such data will enable high risk areas of the pipelines to be addressed and repaired more efficiently and effectively.
- AGN will be able to demonstrate that the pipelines comply with AS 2885.3-2012 (Clause 6.5).
- Baseline data will be obtained for assessing extension of the pipeline life once the design lives are reached.

1.5.3. Option 3 – Recoat Pipelines

The third option that AGN has identified is to recoat all accessible sections of pipelines. Implementing this option will involve pipeline excavation of the majority of the alignment, removal of existing coating, inspection of the pipeline, defect repair where necessary, recoating in-situ with a modern coating and reinstatement. This option would initially focus on areas of the pipelines with large amounts of coating faults.

This option won't allow for the pipelines to be inspected by ILI; however with modern coating materials, application methods and quality control the risk of a pipe wall defect developing to failure point within the design life of the pipeline is greatly reduced. Future management of structural integrity of the pipelines would then rely on indirect assessment of the coating and subsequent direct inspection. Sections which are currently inaccessible, such as underneath river or rail crossings, will not be able to be recoated under this option and will be subject to the same risk as Option 1, but the overall risk on the pipelines would be reduced as the length of pipeline exposed to vintage coating is decreased.

1.5.3.1. Cost/Benefit Analysis

The costs for this option for both pipelines include:

- Costs for recoating the Dandenong to Frankston pipeline have been estimated at $33,500 ($000, 2016).
- Costs for recoating the North Melbourne to Fairfield pipeline have been estimated at $16,700 ($000, 2016).

Although the implementation of this option will reduce the likelihood of a failure event, there is no overall reduction in residual risk for this option for the life of the recoated pipelines. This is because undetected corrosion may still develop on the pipeline, especially in sections which are not accessible. In this regard, it is worth noting that while physically examining the majority of the pipeline length, there will still be areas that cannot be examined, and so AGN will still have difficulty demonstrating that it fully complies with AS 2885.3-2012 (Clause 6.5). It is for these reasons that the residual risk for this option is still rated as High (see Appendix C for more detail).

The benefits of this option are as follows:

- Direct examination of pipelines that are recoated will enable physical inspection, assessment and repair where necessary of the majority of the length of the pipeline.
- Modern coating is also less likely to degrade in the life of the pipeline and is likely to allow for extension of pipeline life.

1.5.4. Option 4 – Additional Dig-Ups

The fourth option AGN has identified is to conduct additional excavations on the pipelines to include all mandatory and half of the candidate sites. This will provide a larger sample size of potential corrosion sites than Option 1, however, will only marginally decrease the risk of unidentified corrosion developing on the pipeline due to the unpredictable and localised nature of corrosion.

1.5.4.1. Cost/Benefit Analysis

The costs for this option include:

- Ongoing operational costs of the pipeline by means of coating inspection and subsequent excavations at mandatory and half of candidate sites of $953 ($000, 2016) and $1,428 ($000, 2016) for the Dandenong to Frankston and North Melbourne to Fairfield pipelines, respectively for the next five yearly inspection. These costs are initial costs estimated from the number of anticipated coating faults requiring excavation into the future (see below), and the estimated cost of coating fault excavations of $12,750 per site, from the recently approved South Australian business case for the same activity (SA21a). Because of the anticipated increase in coating faults, the volume of excavations are expected to escalate over time.

  As the pipeline coatings continue to deteriorate, it is expected that mandatory and candidate coating fault sites will increase by 10 and 64 faults, respectively (which, as in Option 1, is a broad average of the deterioration rate observed across the 2 pipelines, from Table 1.3) for each pipeline for each five yearly coating survey and will subsequently escalate costs. It is thus anticipated that the total number of sites for excavation at each 5 yearly survey will increase by 42 (10 mandatory and 32 candidate sites).
- A worst case failure event could result in loss of supply to the number of customers listed in Section 1.3, at a cost between $15,300 ($000, 2016) or $17,000 ($000, 2016) for the Dandenong to Frankston and North Melbourne to Fairfield pipelines respectively. A failure

event could also result in damage to public property and loss of life. These costs are based on costs of relighting customers and Guaranteed Service Level (GSL) payment for outages longer than 18 hours. In a situation where the pipeline failure is not a worst case failure event, it is likely that some customers can be backfed from other networks and this cost would be lower.

- Some sections of pipelines will remain inaccessible for coating inspection and excavations, such as under river or rail crossings and underneath some sections of road pavement or concrete. These types of sections account for approximately 4.7% and 8.5% of the Dandenong to Frankston and North Melbourne to Fairfield pipeline alignments, respectively.
- With limited means to demonstrate continuing pipeline integrity in a manner which complies with the requirements of AS 2885.3, once the end of a pipeline life is reached it is likely that replacement will be required.

The benefits of this option are as follows:

- Modest reduction in the risk ranking identified in Section 1.4 (refer to Appendix C for risk ranking).
- AGN will have a greater basis for demonstrating compliance with the requirement of AS 2885.3-2012 (Clause 6.5), but will still have difficulty demonstrating that minimum pipe wall thickness is maintained at all locations, as not all locations can be accessed by the pipeline coating measurement inspection method.

1.6. Summary of Cost/Benefit Analysis

Table 1.5: Summary of Cost/Benefit Analysis

Option	Benefits	Costs/Risks
Option 1	No upfront capital costs	• Ongoing costs of $561 ($000, 2016) and $625 ($000, 2016) for pipelines coating inspections escalating every five years, escalating as the coating condition deteriorates • Some sections of the pipeline will remain inaccessible for inspection • Worst case cost of relight and GSL payment costs due to loss of supply of between $15,300 ($000, 2016) to $17,000 ($000, 2016) per occasion. • Residual risk ranking of High
Option 2	The benefits of this option are as follows: • Inspection of entire pipeline through ILI will enable the nature and magnitude of pipeline steel deterioration to be identified and the location accurately determined. • AGN can demonstrate compliance with Clause 6.5 of AS 2885.3. • Baseline data will be obtained for assessing extension of pipeline life • Residual risk reduced from High to Moderate.	• Total cost of $13,951 ($000, 2016) • Ongoing costs of $650 - 683 ($000, 2016) likely every 10 years to conduct ILI runs.

Option 3	• Direct examination of pipeline sections which are recoated, enabling physical inspection and assessment. • AGN can only demonstrate that Clause 6.5 of AS 2885.3 is complied with for the majority of the pipeline, but not at all locations along the full length. • Modern coating less likely to degrade in life of pipelines.	• Total initial cost of $50,200 ($000, 2016) • Residual risk remains High
Option 4	• No upfront capital costs. • Better knowledge of condition of the pipeline. • AGN can only demonstrate that Clause 6.5 of AS 2885.3-2012 is complied with for the areas excavated and (if necessary) repaired, but not at all locations along the full length.	• Ongoing costs of $935 ($000, 2016) and $1,428 ($000, 2016) every five years for pipeline coating inspections, escalating as the coating condition deteriorates • Some sections of the pipeline will remain inaccessible for inspection • Worst case cost of relight and GSL payments due to loss of supply of between $15,300 ($000, 2016) to $17,000 ($000, 2016) per occasion. • Residual risk ranking of High

1.6.1. Cost/Benefit Analysis Modelling

The four options have been subjected to cost / benefit analysis modelling, the results of which are summarised in Table 1.7 below (see Supporting Information 2 for further detail).

Table 1.6: Cost/Benefit Analysis Results

Option	NPV ($000, $2016)
Option 1	**-$20,195**
Option 2	**-$14,881**
Option 3	**-$47,984**
Option 4	**-$33,178**
Discount Rate (real pre-tax WACC)	**3.14%**

As the table shows, Option 2 is the lowest cost option.

An analysis period of 34 years has been used, to provide for the need to replace the pipelines at the end of their design lives in Options 1 and 4, (2046 for Dandenong to Frankston and 2051 for North Melbourne to Fairfield), as described in Section 1.5.1. However, AGN recognises that it is impractical to forecast the need to completely replace both pipelines within this timeframe, and that decisions on replacement would be made much closer to the end of each pipeline's life. AGN has therefore adopted a more conservative approach for the purpose of this NPV analysis, and assumed that only half of each pipeline needs to be replaced. The costs of this ($18,430 ($000, 2016) for Dandenong to Frankston, and $12,790 ($000, 2016)) are shown in years 37-39 of the NPV analysis for Options 1 and 4.

1.7. Proposed Solution

1.7.1. What is the Proposed Solution?

Of the options presented in Section 1.5, Option 2 has been selected because it is the least cost option and the most cost effective way to reduce the risk associated with corrosion and deterioration of pipelines and achieves a reasonable balance between residual risk and cost.

1.7.2. Why are we Proposing this Solution?

Option 2 is being proposed because it provides the most cost effective method of being able to demonstrate structural integrity of the pipelines and lowering the risk of pipeline failure due to unknown deterioration resulting from undetected corrosion. In relation to the other three options, it is worth noting the following:

- While Option 1 is lower cost in terms of immediate capital cost, it does not reduce the risk profile for the pipelines. The total number of coating defects is expected to continue increasing along with the volume of subsequent excavations required. With limited ability to demonstrate continued fitness for purpose at the end of the pipelines' lives, they would require replacement at that time at very high cost.
- Option 3 is technically feasible but is significantly more expensive and so is not considered the most cost-effective solution. It will still result in some areas of the pipeline not being able to be physically examined by direct means.
- Option 4 provides a larger sample of the corrosion sites and issues along the pipeline, but does not provide for full compliance with AS 2885.3, because not all the pipeline is able to be verified for structural integrity.

Additionally, AGN's stakeholder engagement program has helped better understand the values and needs of our stakeholders and customers. During our engagement with customers, we heard that customers valued initiatives that maintain the reliability and improve the safety of our network. Consistent with this, ensuring that corrosion on major transmission mains is minimised and that the integrity of these pipelines is assured contributes to the provision of a safe supply of natural gas.

When it was outlined to customers that the majority of AGN's expenditure program is centred either around maintaining the level of reliability or maintaining and improving network safety, understandably, no participants supported investments to deliver a level of reliability beyond what they currently experience, although they do value the current levels, and are supportive of investment that maintains it.

1.7.3. Forecast Cost Breakdown

1.7.3.1. Capex Component

A detailed cost estimate is included in Appendix D, which provides information for sources of estimates and assumptions. The forecast costs are summarised in the following tables:

Table 1.7: Project Cost Estimate

	2018	2019	2020	2021	2022	Total
Dandenong to Frankston Pipeline	354	1,957	4,992	683	-	7,986
North Melbourne to Fairfield Pipeline	-	267	2,327	2,721	650	5,965
Total	**354**	**2,224**	**7,320**	**3,404**	**650**	**13,952**

Table 1.8: Capex/Opex Split

	2018	2019	2020	2021	2022	Total
Capex	354	2,224	7,320	3,240	486	13,623
Opex	-	-	-	164	164	329
Total	**354**	**2,224**	**7,320**	**3,404**	**650**	**13,952**

The detailed cost breakdown has been prepared for individual items based on the costs of comparable projects recently completed (such as the Amcor Pipeline decommissioning, Wandong City Gate, Melrose Drive Field Regulator, Tumut Valley Pipeline Pigging and Donnybrook City Gate) the bulk of which have been competitively tendered, as well as estimates used for Business Case V54 "Refurbishment of the Dandenong to Crib Point Pipeline".

The following assumptions have been made in preparation of the cost breakdown:

- Compulsory acquisition will not be required to obtain land for the pig trap sites.
- New weld procedures will be required to complete the works.

The timing of the work above reflects the 4 stages of each project:

- Year 1 – Engineering investigation and physical proving
- Year 2 – Pig Trap installation
- Year 3 – Valve replacement
- Year 4 – ILI run and validation / repair excavations

The two projects are staggered by one year so that as one stage (e.g. pig trap installation) is complete on the first pipeline, the same activity will commence on the other.

1.7.3.2. Opex Component

Following the initial ILI, the operating practices for the pipeline will change from indirect measurement of pipeline coating and subsequent coating fault excavations to ILI examinations and subsequent targeted excavations for direct examination of identified defects and comparison of actual defects to the ILI data. This will provide the data for development of future ILIs and repair programs.

It is anticipated from previous experience with pipelines modified to undertake ILIs, that the opex associated with the direct examination excavations generated from ILIs will be similar when compared with those generated from DCVG surveys. This is because while more defect sites would be generated by the ILI, the pipe wall characteristics are measured very accurately by the ILI tool, and the defects and anomalies can be assessed accurately. Thus only those actually requiring repair or detailed examination are excavated, rather than having to perform excavations to assess the pipe wall condition.

Thus a step change in base year opex is not anticipated to be required.

1.7.4. Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN considers the forecast capex for this project to be:

- *Prudent* – AGN has considered four alternatives, and has selected the option, and that which reduces, in the most cost effective manner, the overall residual risk associated with coating degradation in older pipelines to as low as reasonably practicable consistent with AS 2885.3-2012.
- *Efficient* – The estimated costs for this project are considered to be efficient because they are based on a similar program of works developed following an engineering investigation into modifying a pipeline to be able to accommodate an ILI tool (V54 Dandenong to Crib Point). Materials and the construction contractor costs will be obtained through a competitive tender process. The expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would occur.
- *Consistent with accepted good industry practice* – ILI of transmission pipelines is seen as the industry standard for demonstrating pipeline integrity. For pipelines with vintage coatings which are degrading, ILI is the most complete and accurate method available to identify corrosion and other integrity issues and thus ensure the reduction of risk is to as low as reasonably practicable in a manner that balances cost and risk. It will also allow compliance with AS 2885.3-2012 (Clause 6.5) to be demonstrated.
- *Achieves the lowest sustainable cost of delivering pipeline services* – The NPV of the proposed solution is the lowest of the options considered and will also reduce risks to an acceptable level, enabling the delivery of services to continue in a sustainable manner and maintaining reliability of supply at the lowest sustainable cost of delivering pipeline services over the long-term.

The capex can therefore be viewed as being consistent with rule 79(1)(a) of the NGR.

The proposed capex is also consistent with rule 79(1)(b), because the expenditure is necessary to:

- maintain and improve the safety of services (rule 79(2)(c)(i)) by improving the ability to detect potential pipeline leakage location, especially those locations that are inaccessible to ground surface based indirect assessment methods;
- maintain the integrity of services (rule 79(2)(c)(ii)) by providing an enhanced ability to detect deteriorating corrosion protection levels and pipeline defects by carrying out ILI runs; and
- maintain AGN's capacity to meet existing levels of demand for services existing at the time the capex is incurred (rule 79(2)(c)(iv)) by conducting pro-active activities that address potential failures before they occur.

The opex component also satisfies rule 91 because 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.

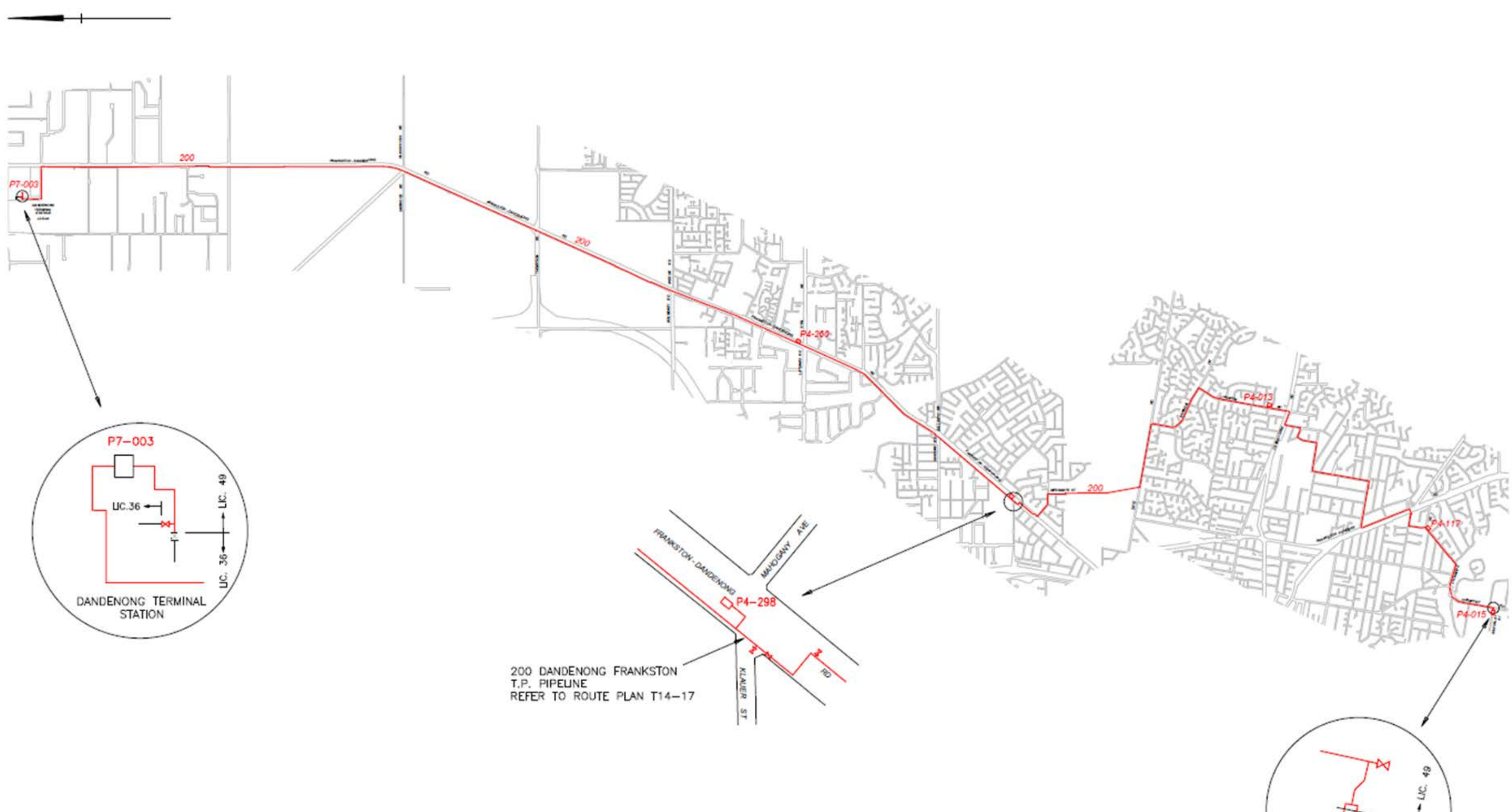
Appendix A Dandenong to Frankston and North Melbourne to Fairfield Technical Details

Table A.1: Summary of Dandenong to Frankston Technical Details

Pipeline Parameter	Value
Original Design Code	USA Standard Code for Pressure Piping USAS B 31.8
Current Operation Code	Australian Standard 2885.3 – Operation and Maintenance
Year Commissioned	1966
MAOP	1,920 kPa
Design Life	80 Years
Design Factor	0.4
Pipeline Size	DN200
Pipeline Length	24.0 km
Pipeline Material	SAA A.33 Class D SAA A149 API 5L Grade B
Pipeline Wall Thickness	6.35 mm
Depth of Burial	760 mm (Minimum)
External Coating	Two coats of coal tar enamel, internally reinforced with random mesh fibreglass followed by an outer wrap of tar impregnated asbestos felt.
Internal Coating	None
Cathodic Protection Units	1
Station Offtakes	5
Pipeline Offtakes	2
Location Classes	T1, R2, HI, S, HI, I, CIC, W
Original Design Code	USA Standard Code for Pressure Piping USAS B 31.8
Current Operation Code	Australian Standard 2885.3 – Operation and Maintenance
Year Commissioned	1966

Table A.2: Summary of North Melbourne to Fairfield Technical Details

Pipeline Parameter	Value
Original Design Code	USA Standard Code for Pressure Piping USAS B 31.8
Current Operation Code	Australian Standard 2885.3 – Operation and Maintenance
Year Commissioned	1971
MAOP	1,896 & 2, 760 kPa
Design Life	80 Years
Design Factor	0.4
Pipeline Size	DN 250
Pipeline Length	11.1 km
Pipeline Material	API 5L Grade A
Pipeline Wall Thickness	6.35 mm
Depth of Burial	1,200 mm (Minimum)
External Coating	Coal tar enamel layer approximately 2.4 mm thick. Internally reinforced with a random mesh fibreglass mat and externally reinforced with a bonded tar impregnated asbestos felt outer wrapping.
Internal Coating	None
Cathodic Protection Units	0
Station Offtakes	10
Pipeline Offtakes	0
Location Classes	T2, T1, S, I, CIC, W



ASSETS OWNED BY
VIC GAS DISTRIBUTION PTY LTD.
AND OPERATED UNDER LICENCE 49

CURRENT AUTHORISED ROUTE

TOTAL RECORDED LENGTH OF LICENCE 49
OWNED BY VIC GAS DISTRIBUTION PTY LTD.
200NB DANDENONG TO FRANKSTON 24.0km.

A	16/6/11	REDRAWN. ALL PREVIOUS REVISIONS INCLUDED.	J.R.S.	H.W.	G.S.
NO	DATE	REVISION	DRN	CKD	APP

ROUTE PLAN	T14-13 to T14-20
REFERENCE DRAWINGS	DRG.NO.

APA Group

Envestra

SCALE AS SHOWN

DRAWN J. SCIMONE JUNE 2011

CHECKED

LICENCE PLAN

LICENCE NO. 49

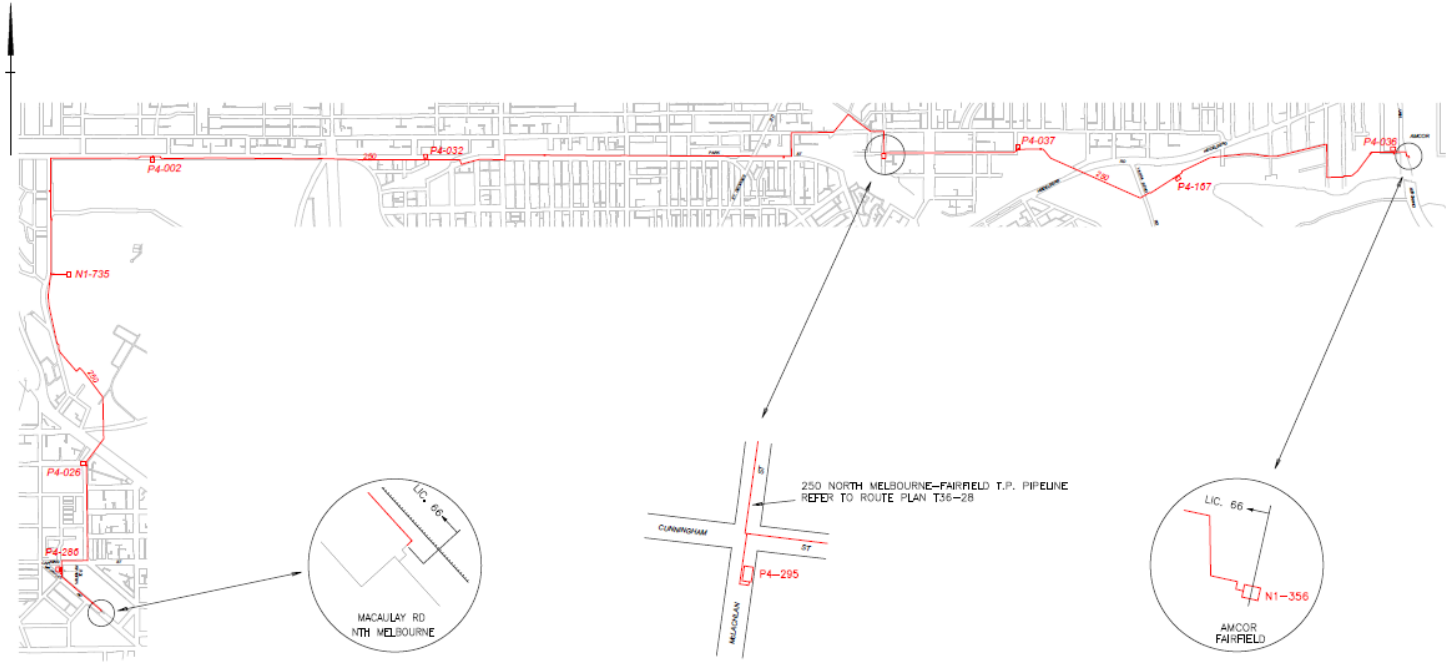
DANDENONG TO FRANKSTON

DESIGN ENGINEER

APPROVING ENGINEER

T14-1-1

A



ASSETS OWNED BY
VIC GAS DISTRIBUTION PTY LTD.
AND OPERATED UNDER LICENCE 66

CURRENT AUTHORISED ROUTE

TOTAL RECORDED LENGTH OF LICENCE 66
OWNED BY VIC GAS DISTRIBUTION PTY LTD.
250NB NORTH MELBOURNE TO FAIRFIELD 11.1km.

NO	DATE	REVISION	DRN	CKD	APP
A	20/6/11	REDRAWN, ALL PREVIOUS REVISIONS INCLUDED.	J.R.S.	H.M.	G.S.

REFERENCE DRAWINGS	DRG.NO.
ROUTE PLAN	T36–13 to T36–35

APA Group
Envestra

SCALE AS SHOWN
DRAWN J. SCIMONE May 2011
CHECKED
DESIGN ENGINEER
APPROVING ENGINEER

LICENCE PLAN LICENCE NO. 66
NORTH MELBOURNE TO FAIRFIELD
T036–1–2 A

Appendix B AER Extracts

Extract from AER Access arrangement draft decision, APA GasNet Australia (Operations) Pty Ltd, 2013–17, Part 1, Page 51 [8]

Table 3.7 provides a summary of the significant refurbishment and upgrade projects and the costs forecast by APA GasNet. The highest forecast refurbishment and upgrade project cost is $8.6 million ($2012) for the installation of pig traps with the next highest at $4.0 million ($2012) for the actuation of mainline valves project. APA GasNet has provided business cases for each of the refurbishment and upgrade projects over $0.5 million ($2012) outlining the requirement and justification of each project. The AER has reviewed the business cases submitted by APA GasNet and assessed its proposed refurbishment and upgrade capex program on the basis of whether the key project drivers identified by APA GasNet comply with the conforming capital expenditure criteria in r. 79 of the NGR. In particular, the AER considers:

- *a gas transmission business is required to maintain the structural integrity of its high pressure pipelines. The AER considers that APA GasNet's proposed Pipeline Integrity expenditure is necessary to mitigate the associated safety and reliability risks in operating high pressure pipelines. In particular, the AER considers that the investment proposed by APA GasNet in relation to its in-line inspection pigging program and installation of pig traps is prudent given the physical environment its coated steel pipes are exposed to. This is consistent with good industry practice*
- *a gas transmission business is also required to mitigate the risks faced by its facilities and pipelines to expected hazards. The AER considers that APA GasNet's proposed Facilities Integrity capex program effectively reduces known risks faced by its facilities and pipelines. The AER considers that investing in upgrades to its facilities and pipelines to mitigate known hazards rather that replacing assets is prudent*

On the basis of its review, the AER is satisfied that the refurbishment and upgrade projects are necessary to maintain the safety, reliability and integrity of the VTS.178 The AER considers that this is consistent with observations made by the Energy Users Coalition of Victoria that although the drivers for the underspend during the 2008–12 access arrangement period remain essentially unchanged, the forecast refurbishment and upgrade program at about $10 million per year appears to be reasonable when considering APA GasNet's expenditure for the past five years averages this amount.179

The AER considers that although APA GasNet's proposed refurbishment and upgrade capex program is necessary to maintain the safety, reliability and integrity of the VTS, it does not comply with r. 74(2) of the NGR because the AER does not accept APA GasNet's proposed labour cost escalators.

[8] Please note that items which are not relevant to this business case have been removed from this extract.

Extract from AER Access arrangement final decision, Envestra Ltd, 2013–17, Part 2: Attachments, Page 135

The AER's final decision on other non-demand capex is set out in Table 4.28and Table 4.29.

Table 1.1 Victoria Final decision – Other non-demand capex ($million 2011)[(a)]

	2013	2014	2015	2016	2017	Total
Field asset refurbishment	1.320	1.320	1.320	1.320	1.320	6.600
Dandenong to crib point pipeline	**1.100**	**2.000**	**2.186**	**0.680**	**0.375**	**6.341**
Plant and Equipment	0.891	1.331	0.281	0.231	0.231	2.965
TD Williamson	0.200	0.200	0.200	0.000	0.000	0.600
City Gate Lightning	0.129	0.129	0.118	0.107	0.107	0.590
Mains Alteration	0.109	0.109	0.109	0.109	0.109	0.545
City Gate Lagging	0.052	0.052	0.052	0.052	0.052	0.260
Storm water Survey	0.200	0.000	0.000	0.000	0.000	0.200
Anode bed replacement	0.053	0.035	0.035	0.035	0.035	0.193
Waterbath heaters	0.031	0.031	0.031	0.031	0.031	0.155
Refurb transmission valves and Pig traps	0.014	0.014	0.018	0.014	0.013	0.072
Bushfire Preparedness	-	-	-	-	-	-
Network monitoring and control	-	-	-	-	-	-
Interval meter data management	-	-	-	-	-	-
Regional Scada	-	-	-	-	-	-
NECF	-	-	-	-	-	-
Vegetation management	-	-	-	-	-	-
Flow Correctors	-	-	-	-	-	-
Technical Training	-	-	-	-	-	-
Total	4.099	5.221	4.350	2.579	2.273	18.521

Source: AER analysis

Note: (a) Direct costs, excluding escalation and overheads

Appendix C Risk Assessment

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Option Risk
Risk Untreated	**Likelihood**	*Unlikely*	*Unlikely*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	**HIGH**
	Consequence	*Medium*	*Minor*	*Major*	*Significant*	*Significant*	*Medium*	*Major*	
	Risk Level	*Moderate*	*Low*	*High*	*High*	*High*	*Moderate*	*High*	
Residual Risk Option 1	**Likelihood**	*Unlikely*	*Unlikely*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	**HIGH**
	Consequence	*Medium*	*Minor*	*Major*	*Significant*	*Significant*	*Medium*	*Major*	
	Risk Level	*Moderate*	*Low*	*High*	*High*	*High*	*Moderate*	*High*	
Residual Risk Option 2	**Likelihood**	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	**MODERATE**
	Consequence	*Medium*	*Minor*	*Major*	*Significant*	*Significant*	*Medium*	*Major*	
	Risk Level	*Low*	*Negligible*	*Moderate*	*Moderate*	*Moderate*	*Low*	*Moderate*	
Residual Risk Option 3	**Likelihood**	*Rare*	*Rare*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	**HIGH**
	Consequence	*Medium*	*Minor*	*Major*	*Significant*	*Significant*	*Medium*	*Major*	
	Risk Level	*Low*	*Negligible*	*High*	*Moderate*	*Moderate*	*Moderate*	*High*	
Residual Risk Option 4	**Likelihood**	*Unlikely*	*Unlikely*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*HIGH*
	Consequence	*Medium*	*Minor*	*Major*	*Significant*	*Significant*	*Medium*	*Major*	
	Risk Level	*Moderate*	*Low*	*High*	*High*	*High*	*Moderate*	*High*	

Appendix D Cost Estimate

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Business Case – Capex V91

Odorant Injection Station

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	Michael Gallagher, *Engineering Manager*
Approved By	Andrew Foley, *General Manager Victorian Networks*

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	Through periodic testing, Australian Gas Networks Limited (AGN) has found that odorant levels in the Tocumwal town network can fall below the minimum threshold set out in regulatory standards (i.e. gas should have a distinctive odor at the required threshold of one-fifth of the lower explosive limit of natural gas) in the summer months because low demand in this period results in low gas velocities along the supply main. Low odorant levels may mean that a leak of gas from the network or on the customer downstream supply might not be detected with the consequential risk of fire, explosion, damage to property, injury or loss of life. To manage this risk, operational personnel are currently making special trips to Koonoomoo and Tocumwal to manually dose the network with odorant every two months. There is, however, a risk of under or overdosing with manual dosing. AGN has therefore investigated other options to manage this risks in the Tocumwal town network.
Options Considered	The following options have been considered: 1 Option 1: Maintain current regime of manual dosing of Finley network. 2 Option 2: Install an odorant dosing unit Koonoomoo City Gate 3 Option 3: Reduce the outlet pressure at the Koonoomoo City Gate to 400 kPa to increase velocity along the DN200 pipeline. Install bypass spools at Tocumwal and Finley regulators. 4 Option 4: Replace the DN200 pipeline with DN125 PE pipeline to increase velocity of gas to Tocumwal. While the latter of these options has been considered, network modelling shows that it will not address the risks of the low odorant levels.
Proposed Solution	Option 2 has been selected because it is the most cost effective way of addressing the risks posed by the low odorant levels in the Tocumwal network in summer.
Estimated Cost	The forecast capital expenditure for this project is $259 ($000, 2016) over the next (2018 – 2022) Access Arrangement (AA) period.

Consistency with the National Gas Rules (NGR)	The proposal to install an odorant facility at the Koonoomoo City Gate complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because:
	• 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)); and
	• it is justified under 79(2)(c) as it is required to:
	  • maintain and improve the safety of services (79(2)(c)(i));
	  • comply with a regulatory obligation or commitment (79(2)(c)(iii)); and
	  • maintain the capacity to meet existing levels of demand (79(2)(c)(iv)).

Stakeholder Engagement	A key outcome of the stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is consistent with the Safety theme as its implementation will allow AGN to maintain the safe supply of natural gas to our customers by ensuring the required concentrations of odorant are maintained in the Tocumwal network. More information detailing the results of the stakeholder engagement program is provided in Chapter 5 of the Access Arrangement Information document

1.3. Background

1.3.1 Odorisation of Gas Networks

For safety reasons, natural gas systems are injected with mercaptan odorant to provide a distinctive smell, which allows the public to detect gas in the local atmosphere. The odorant is a critical safety component and there are regulations that require certain odorant levels to be maintained. The regulatory requirements governing odorant levels in gas networks in Victoria and NSW are set out in the following legislation:

- Victoria - Gas Safety (Gas Quality) Regulations 2007
- Victoria - Essential Services Commission – Gas Distribution System Code (GDSC)
- Victoria - AEMO Gas Quality Standard
- Victoria - AEMO Gas Quality Guidelines
- NSW - Gas Supply (Safety and Network NSW)

The relevant excerpts governing the levels and quality of odorant supplied are detailed in Appendix E. The regulations require that in the event of low odorant, the gas distributor may add supplementary odorant dosing into the pipeline. This is a course of action that AGN has been undertaking.

1.3.2 AGN's Koonoomoo and Tocumwal networks.

As shown in Appendix B, the AGN (Albury) and AGN (Northern Vic) networks are fed by the APA Rutherglen to Koonoomoo transmission pipeline DN200 T98-20. The Koonoomoo City Gate, which is owned by AGN, feeds the towns of Tocumwal, Barooga and Finley via a 26km DN200 steel supply pipeline which operates with an MAOP of 1050 kPa. Refer to Appendix C for a diagram of the network. The DN200 1050 kPa supply pipeline was built in 1998. In addition to Tocumwal, Barooga and Finley, the pipeline was originally designed with capacity to supply the towns of Deniliquin and Berrigan. To date, the DN200 supply main terminates at the town of Finley and there is no indication Deniliquin or Berrigan will be supplied with gas in the medium term.

Through periodic testing, AGN has found that the odorant levels in the Tocumwal town network can fall below the minimum regulatory levels during periods of low gas demand, as a result of low velocities in the DN200 pipeline. The low velocities occur because the pipeline diameter (DN200) is larger than would have been designed and installed if Deniliquin and Berrigan had not been considered.

Appendix D sets out the results of the odorant testing reports that GTS (AGN's odorant testing contractor) conducted in Tocumwal in January and October 2015, and an example report of gas sampling, both demonstrating low odorant levels. These reports show that over the time period, odorant levels have been consistently below the regulatory requirement. As shown in Appendix E, the odorant must be injected into the network at a rate of 7mg/m3 of gas with a composition of 70% THT to 30% TBM[1].The reports show that at Tocumwal, the rate of odorant is 5.7mg/m3 in January with a composition 98.3% THT to 1.7% TBM.

To date, the problem has been addressed by operations personnel manually dosing the network and pipeline at Koonoomoo and Tocumwal. This solution is reactive and inefficient, and requires personnel to travel from Thomastown in Victoria to Koonoomoo in NSW every two months.

1.4. Risk Assessment

A risk assessment has been carried out using APA's established evaluation criteria (detailed in Appendix A – Risk Assessment) to produce an estimated level of risk, which is summarised in Table 1.3. As this table highlights, the untreated risk associated with the odorant levels in the Tocumwal network during the summer months is "High".

Table 1.3: Risk Rating

Risk Area	Untreated Risk Level
Health and Safety	High
Environment	Low
Operational	Moderate
Customers	Negligible
Reputation	Moderate
Compliance	Moderate
Financial	Negligible
Untreated Risk Rating	**High**

The key risk is to health and safety, particularly the safety risk to the public. When odorant levels are too low, gas leaks are not as easily detected, which increases the risk of undetected leaks building up in areas where ignition sources exist that may result in fire, explosion and subsequent injury or loss of life.

The current manual dosing method for providing odorant into the network also carries the risk of either overdosing or under dosing the network because the quantity of odorant used in manual operation is fixed and is not necessarily proportional to flow requirements and there is limited

[1] THT = Tetrahydrothiopene, TBM = Tertiary –Butyl Mercaptan

control over odorant levels when manual dosing. As outlined above, under dosing increases the risks of leaks not being detected, while overdosing can result in more leaks being reported, and a subsequent higher level of response call outs and associated costs.

The other key risk is that AGN will fail to comply with its regulatory obligation to ensure that odorant levels are maintained above the regulatory limit of 7mg m3 of gas of 70% THT and 30% TBM (see Appendix E).

1.5. Options Considered

AGN has identified the following options to address the risks outlined in section 1.4:

- Option 1: Do nothing;
- Option 2: Install an odorant dosing unit at the Koonoomoo City Gate;
- Option 3: Reduce outlet pressure at the Koonoomoo City Gate to 400 kPa to increase velocity along the DN200 Tocumwal pipeline. Install bypass spools at Tocumwal and Finley regulators; or
- Option 4: Replace the DN200 pipeline with a DN125 PE pipeline to increase velocity of gas to Tocumwal.

1.5.1 Option 1 – Do Nothing

Under this option AGN would continue to maintain natural gas odorant levels at minimum levels or above by manually dosing the Koonoomoo City Gate. This dosing would occur every two months with approximately 100ml of odorant manually dosed into the Tocumwal network.

1.5.1.1 Cost/Benefit Analysis

The benefit of this option is that it avoids upfront capital expenditure, but AGN will still incur the costs of manually dosing the network. Manually dosing the Tocumwal network requires six trips a year by two operations personnel (i.e. one every two months) and costs approximately $3,000 per annum.

As outlined in section 1.4, manually dosing the Tocumwal poses the risk of under or over dosing the network, which is why the risk associated with this option is High.

1.5.2 Option 2 – City Gate Odorant unit at Koonoomoo

The benefit of this option is that it avoids upfront capital expenditure, but AGN will still incur the costs of manually dosing the network. Manually dosing the Tocumwal network requires six trips a year by two operations personnel (i.e. one every two months) and costs approximately $3,000 per annum.

As outlined in section 1.4, manually dosing the Tocumwal poses the risk of under or over dosing the network, which is why the risk associated with this option is High.

1.5.2.1 Cost/Benefit Analysis

The benefit of this option is that the city gate odorant unit injects odorant into the outlet from the city gate will be proportional to the flow rate requirements of the downstream network. The amount of odorant injected into the gas flow will be controlled to avoid the risk of under/over dosing the network, allowing consistent odorant levels to be maintained, and reducing the safety risk to the public. The residual risk will therefore be reduced from High to Moderate under this option (see Appendix A). Installing a local odorant unit will also remove the requirement to manually dose the Tocumwal network every two months.

The cost of installing an odorant pump and odorant tank is estimated to be $259 ($000, 2016) (see section 1.7.3 for more detail). There is also an annual operating cost associated with the odorant tank of $2,000. This estimate is based on actual costs of similar odorant project completed.by AGN.

There is little operational risk that the unit may fail, as these units have proven to be very reliable for many years.

1.5.3 Option 3 – Koonoomoo to Finley

The third option AGN has identified is to install a new DN125 Polyethylene (PE) distribution supply pipeline from Koonoomoo to Tocumwal and abandon the existing DN200 steel supply main from Koonoomoo to Tocumwal.

1.5.3.1 Benefit Analysis

Network modelling of this option shows that a pipeline of this smaller diameter achieves the necessary velocities to avoid odorant fade in the supply pipeline and maintain the odorant levels at Tocumwal with the need for additional odorant dosing. The main benefit of this option is therefore that the minimum required odorant levels will be maintained, which will reduce the risk to public safety and the regulatory compliance risk. The residual risk under this option is therefore Moderate

The cost of installing a new DN125 PE supply main is estimated to be $1,500 ($000, 2016), which is based on historical costs of similar projects.

Although this option addresses the issue of odorant fade, it introduces the risk of curtailing network growth if the DN200 is abandoned. Should the townships of Deniliquin and Berrigan be reticulated in the future, further capex would be required to duplicate the new DN125 supply main.

It is also worth noting that the existing DN200 main was installed in 1998 is in good condition, and has a remaining life of 60 years. To abandon it purely to replace it with another asset so that adequate odorant levels is not a prudent or efficient use of an existing asset.

1.5.4 Option 4 – City Gate Koonoomoo – outlet pressure reduction to 400 kPa

The fourth option AGN has identified is to reduce the outlet pressure at the Koonoomoo city gate to increase the velocity of the gas along the steel supply main which feeds Finley, Tocumwal and Barooga. This option would require the adjustment of the regulators at Koonoomoo and the bypassing and decommissioning of the below ground regulator pits at Tocumwal and Finley.

1.5.4.1 Cost/Benefit Analysis

While the cost of this option is relatively low (estimated $60 ($000, 2016), network modelling shows that reduced outlet pressure at Koonoomoo will not produce any benefits for the odorant level problem at Tocumwal. The modelling shows that the minimum pressures required for adequate supply would be 500 kPa, but this would have no appreciable effect on the velocities along the supply pipeline to Tocumwal during the summer months. Inadequate odorant levels would still be a problem, with the attendant risks set out in section 1.4.

In addition, there exists the risk that lower the pressure at Koonoomoo could inhibit future network growth. In theory, should the network demand grow then the pressure could simply be raised again, but this may not result in flow velocities high enough to avoid the odorant fade issue.

1.6. Summary of Cost/Benefit Analysis

A summary of the costs and benefits of the four options is shown in Table 1.4 below.

Table 1.4: Summary of Cost/Benefit Analysis ($000, 2016)

Option	Benefits	Costs/Risks
Option 1: Do nothing - Continue manual dosing	No upfront capital expenditure on new odorant unit	Annual opex costs for manual dosing approximately $3 ($000, 2016) Current risk of over or under dosing is not addressed. Undetected gas leaks may result in gas build-up, subsequent fire or explosion. Regulatory risk of non-compliance with standards not addressed
Option 2: Odorant unit at Koonoomoo	Reduce the public risk by maintaining minimum odorant levels Maintain levels of odorant compliant with standards in the Finley network. Reliable equipment - very low risk of failure. Residual risk Moderate	Capex of $259 ($000, 2016)
Option 3: Pipeline replacement	New DN125 PE supply pipeline will result in increased velocities along the pipeline to overcome odorant fade. No requirement for additional odorant station at Koonoomoo Residual risk Moderate	Capex of $1,500 ($000, 2016) Limited capacity of new pipeline - Potential to support growth is reduced. Duplication of the supply main would be required to supply Deniliquin and Berrigan
Option 4: City gate pressure reduction	This option produces no benefit. Network modeling demonstrates that lowering the outlet pressure at Koonoomoo will not increase the velocity of the gas to overcome odorant fade in the pipeline Residual risk High	Capex of $60 ($000, 2016) Current risk of odorant fade and inadequate odorant levels is not addressed Undetected gas leaks may result in gas build-up, subsequent fire or explosion. Regulatory risk of non-compliance with odorant standards not addressed

1.7 Proposed Solution

1.7.1 What is the Proposed Solution?

The preferred option is to install an odorant facility at the Koonoomoo City Gate, which will allow odorant dosing of the network proportional to the flow rate.

1.7.2 Why are we Proposing this Solution?

AGN is proposing to install the odorant unit because it is the most cost-effective way of managing the risks associated with manual dosing, which includes both the risk to public safety and the risk of not complying with the odorisation regulatory requirements set out in Appendix E.

AGN has also taken into account the following factors in the selection of this option:

- *Technical* – installing an odorant unit at Koonoomoo City Gate addresses the issue of odorant fade caused by low demand. The odorant levels at Tocumwal can be adjusted without the need to manually dose the network. The other low cost option (reducing the supply main pressure) does not solve the problem of low odorant levels during low demand.
- *Cost Effectiveness* – The odorant unit is the more capital cost effective solution than other options considered (i.e. replacing the supply main ($259,000 v $1.5 million).
- *Project delivery* – The project will be delivered by December 2018 with the current resource levels. A mixture of internal, external labour will be used to complete the construction, with an external supplier providing the odorant unit. This will allow the odorant unit to be in place during the low demand period and maximize the reduced opex for manually dosing the network.
- *Stakeholder feedback* - AGN has undertaken a comprehensive engagement program to better understand the values of stakeholders. During this engagement, stakeholders noted that they valued initiatives that improve the safety of the network. Consistent with this insight, improving the odorisation of this section of the network will improve the safety of services.

1.7.3 Forecast Cost Breakdown

The scope of works to install a compact odorant unit at the Koonoomoo City Gate includes:

- *Procurement* - Procurement of a compact odorant unit, 50L odorant tank and appropriate odorant such as Spotleak 1005 from International Chemical Engineering (ICE) based in Bayswater, Melbourne, Victoria.
- *Design and Planning* - Design of the odorant unit at the Koonoomoo City Gate. The design of the compound will be required to protect the unit from the environment, authorised access and potential damage from vehicle impacts, and will be undertaken by AGN. Design will include SCADA alarms to indicate out of performance issues.
- *Installation* – The installation will be carried out by external contractors, who will be selected through a competitive tender process. The installation stage will also involve testing odorant tubing, fittings and pressure control.
- *Commissioning* – Once the facility is installed it will need to be commissioned. The odorant supplier will also need to provide onsite training for AGN operations personnel.

Tables 1.6 and 1.7 set out the forecast cost of carrying out this project, which has been developed having regard to the costs AGN has incurred installing similar units in our South Australian network. In arriving at this estimate, the following assumptions have been made:

- Labour rates for internal and contract resources are based on current 2016 hourly rates, with the contract rates based on the outcomes of a competitive tendering process;
- Costs for the odorant tank and odorant are based on current tendered prices; and
- The proposed expenditure profile for this project is to complete and commission the odorant unit by December 2018. This will allow the unit to be in operation for the low summer demand.

Appendix G provides further detail on this estimate.

Table 1.5: Estimated Cost of Odorant Station Installation ($000, 2016)

Item	Cost
Odorant unit	[redacted]
Odorant tank - 50L	[redacted]
Foundation & bunding design	[redacted]
Geographical survey	[redacted]
Vehicle protection	[redacted]
Warning signage	[redacted]
Drainage design	[redacted]
Scada - upgrade	[redacted]
Material - tubing, fittings, vent pipes	[redacted]
Slab + building	[redacted]
Contractor -commissioning	[redacted]
Contractor –training for AGN	[redacted]
Contract - labour - excavation	[redacted]
Direct labour- commission	[redacted]
Total	**259**

Table 1.6: Capex ($000, 2016)

	2018	2019	2020	2021	2022	Total
Material	210	-	-	-	-	210
Labour	49	-	-	-	-	49
Total	**259**	**-**	**-**	**-**	**-**	**259**

1.7.4 Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN considers the forecast capex for this project to be:

- *Prudent* – Maintaining odorant levels at the regulatory minimum is required to enable the public to be able to identify gas leaks and report them to AGN. The expenditure is necessary to ensure that these minimum levels are maintained and there are no major gas escapes that could impact public safety and reliability of supply. AGN has considered several alternative solutions to this problem and has selected the one that effectively balances cost and risk. The expenditure is therefore of a nature that a prudent service provider would incur.
- *Efficient* – The project will be carried out by a mixture of internal and external labour, with the procurement, installation and commissioning of the odorant unit to be carried out by a recognised odorant specialist that has extensive experience in completing the installation of the facilities in a safe and cost effective manner. The external labour and odorant specialist will be selected through a competitive procurement process. The expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.
- *Consistent with accepted good industry practice* – Addressing the risks posed by low odorant levels is accepted good industry practice and required by the Victorian Gas Distribution System Code, the Victorian Gas Safety (Gas Quality) Regulations and AMEO gas quality standards and safety guidelines (see Appendix E).
- *Achieves the lowest sustainable cost of delivering pipeline services* – Installing the odorant unit is the most cost effective solution to deal with the risks posed by low odorant levels and will result in a lower sustainable cost of delivering services over the longer term.

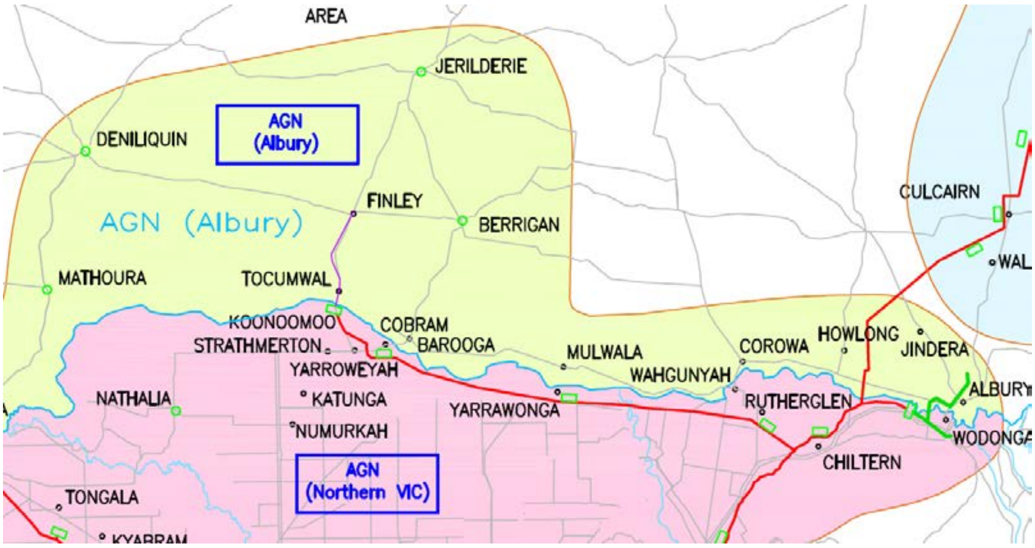
The capex can therefore be viewed as being consistent with Rule 79(1)(a) of the NGR. The proposed capex is also consistent with Rule 79(1)(b), because the expenditure is necessary to:

- *maintain and improve the safety of services (rule 79(2)(c)(i))* - by reducing public risk of an undetected gas leak by maintaining minimum odorant levels; and
- *comply with a regulatory obligation or requirement (rule 79(2)(c)(iii))* - by maintaining odorant levels at regulatory minimum for gas detection.

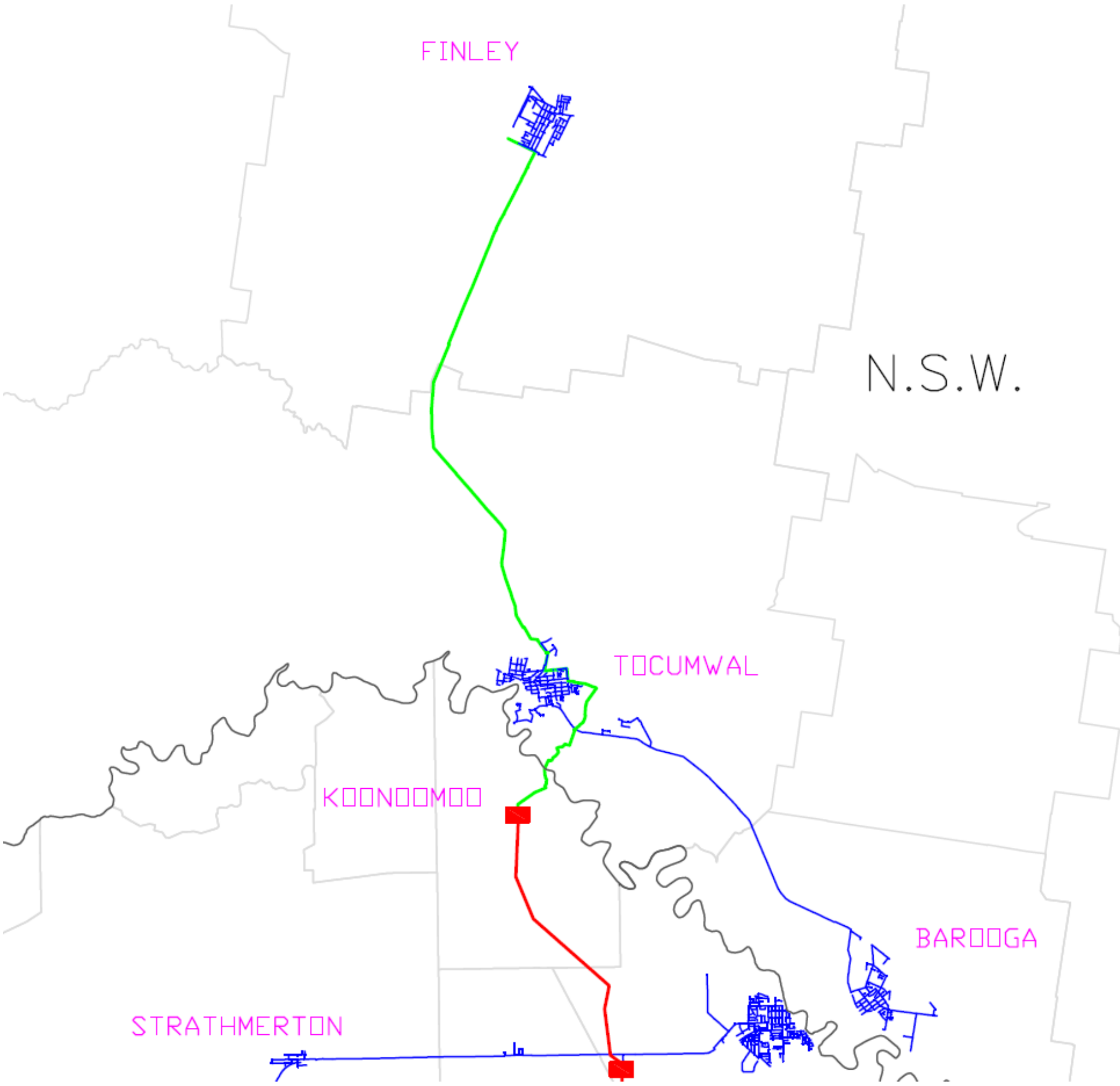
Appendix A Risk Assessment

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels
Risk Untreated + Option 1 - Do nothing	**Likelihood**	*Occasional*	*Likely*	*Likely*	*Unlikely*	*Possible*	*Possible*	*Unlikely*	
	Consequence	*major*	*Insignificant*	*Minor*	*Insignificant*	*Medium*	*Medium*	*Insignificant*	
	Risk Level	*High*	*Low*	*Moderate*	*Negligible*	*Moderate*	*Moderate*	*Negligible*	*HIGH*
Residual Risk Option 2 Install Odorant injection at Koonoomoo	**Likelihood**	*Unlikely*	*Unlikely*	*Rare*	*Unlikely*	*Rare*	*Rare*	*Rare*	
	Consequence	*Major*	*Insignificant*	*major*	*Insignificant*	*Medium*	*Medium*	*Insignificant*	
	Risk Level	*Moderate*	*Negligible*	*Moderate*	*Negligible*	*Low*	*Low*	*Negligible*	*Moderate*
Residual Risk Option 3: Pipeline replacement Koonoomoo to Finley	**Likelihood**	*Unlikely*	*Unlikely*	*Rare*	*Unlikely*	*Rare*	*Rare*	*Rare*	
	Consequence	*Major*	*Insignificant*	*major*	*Insignificant*	*Medium*	*Medium*	*Insignificant*	
	Risk Level	*Moderate*	*Negligible*	*Moderate*	*Negligible*	*Low*	*Low*	*Negligible*	*Moderate*
Residual Risk Option 4 Reduce city gate outlet pressures at Koonoomoo	**Likelihood**	*Occasional*	*Likely*	*Likely*	*Unlikely*	*Possible*	*Possible*	*Unlikely*	
	Consequence	*major*	*Insignificant*	*Minor*	*Insignificant*	*Medium*	*Medium*	*Insignificant*	
	Risk Level	*High*	*Low*	*Moderate*	*Negligible*	*Moderate*	*Moderate*	*Negligible*	*HIGH*

Appendix B AGN – Albury and Northern Vic Networks



Appendix C AGN – Finley, Tocumwal and Barooga Networks



Appendix D Odorant test results for AGN Northern Region – Jan & Oct 2015

Tocumwal result highlighted in yellow in row R. AGN contractors Gas Technology Services (GTS) regularly test the quality of odorant across the network. The report below demonstrates the results in the Northern region. The sampling points are given from row A to R. The results for Tocumwal are shown to be below the minimum required.

Gas Technology Services
Utilities Division

Page 3 of 4

Northern Region Natural Gas Quality and Odour Survey – January 2016

Gas Quality and Odour Testing *

		A	B	C	D	E	F
Oxygen	mole%	< 0.02	< 0.02	< 0.02	< 0.02	< 0.02	< 0.02
Nitrogen	mole%	0.49	0.69	0.66	0.73	0.63	0.68
Carbon Dioxide	mole%	4.32	3.71	4.15	3.55	3.98	4.16
Total inert gas	mole%	4.82	4.41	4.82	4.29	4.62	4.86
Heating Value	MJ/m^3	38.10	38.02	38.19	38.07	38.40	38.17
Wobbe Index	MJ/m^3	47.80	48.04	47.89	48.16	48.14	47.86
Relative Density		0.635	0.626	0.636	0.625	0.636	0.636
Hydrogen Sulfide	mg/m^3	0.4	< 0.1	0.4	< 0.1	0.6	< 0.1
Total Sulfur	mg/m^3	3	2	3	2	3	2
tertiary-Butyl Mercaptan	mg/m^3	2.7	2.8	3.0	1.7	2.9	1.6
Tetrahydrothiopene	mg/m^3	4.3	4.1	4.5	2.9	5.2	4.4

		G	H	I	J	K	L
Oxygen	mole%	< 0.02	< 0.02	< 0.02	< 0.02	< 0.02	< 0.02
Nitrogen	mole%	0.74	0.75	0.69	0.74	0.73	0.71
Carbon Dioxide	mole%	3.60	3.56	3.70	3.67	3.73	4.02
Total inert gas	mole%	4.35	4.32	4.40	4.42	4.47	4.74
Heating Value	MJ/m^3	38.03	38.02	38.10	38.23	38.20	37.89
Wobbe Index	MJ/m^3	48.10	48.12	48.10	48.18	48.13	47.77
Relative Density		0.625	0.624	0.627	0.630	0.630	0.629
Hydrogen Sulfide	mg/m^3	0.4	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1
Total Sulfur	mg/m^3	3	3	3	2	2	2
tertiary-Butyl Mercaptan	mg/m^3	2.8	2.8	2.8	2.1	< 0.1	2.1
Tetrahydrothiopene	mg/m^3	4.2	4.6	4.6	3.3	4.3	3.6

		M	N	O	P	Q	R
Oxygen	mole%	< 0.02	< 0.02	< 0.02	< 0.02	< 0.02	
Nitrogen	mole%	0.68	0.74	0.76	0.67	0.61	
Carbon Dioxide	mole%	4.21	3.60	3.50	4.39	4.51	
Total inert gas	mole%	4.90	4.36	4.27	5.07	5.13	
Heating Value	MJ/m^3	37.90	38.24	38.42	37.87	37.95	
Wobbe Index	MJ/m^3	47.67	48.23	48.39	47.55	47.54	
Relative Density		0.632	0.629	0.630	0.634	0.637	
Hydrogen Sulfide	mg/m^3	< 0.1	< 0.1	1.1	< 0.1	0.3	< 0.1
Total Sulfur	mg/m^3	2	2	4	3	3	2
tertiary-Butyl Mercaptan	mg/m^3	2.0	1.9	2.9	2.3	2.7	< 0.1
Tetrahydrothiopene	mg/m^3	3.6	4.7	4.9	5.4	4.5	5.6

Northern Region Natural Gas Quality and Odour Survey – October 2015

Gas Quality and Odour Testing *

		A	B	C	D	E	F
Oxygen	mole%	< 0.02	< 0.02	< 0.02	< 0.02	< 0.02	< 0.02
Nitrogen	mole%	0.51	0.59	0.79	0.64	0.78	0.84
Carbon Dioxide	mole%	3.97	3.66	2.67	3.42	2.50	2.31
Total inert gas	mole%	4.49	4.26	3.47	4.06	3.29	3.16
Heating Value	MJ/m^3	38.25	38.24	38.25	38.25	38.25	38.36
Wobbe Index	MJ/m^3	48.10	48.25	48.80	48.39	48.92	49.07
Hydrogen Sulfide	mg/m^3	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1
Total Sulfur	mg/m^3	3	3	2	3	2	4
tertiary-Butyl Mercaptan	mg/m^3	2.7	2.7	2.3	2.4	2.4	2.5
Tetrahydrothiopene	mg/m^3	4.7	4.6	3.5	5.3	3.9	8.7

		G	H	I	J	K	L
Oxygen	mole%	< 0.02	< 0.02	< 0.02	< 0.02	< 0.02	< 0.02
Nitrogen	mole%	0.77	0.80	0.81	0.81	0.78	0.83
Carbon Dioxide	mole%	2.47	2.35	2.35	2.28	2.34	2.44
Total inert gas	mole%	3.25	3.16	3.18	3.10	3.13	3.28
Heating Value	MJ/m^3	38.36	38.36	38.41	38.38	38.33	38.20
Wobbe Index	MJ/m^3	49.00	49.07	49.09	49.12	49.06	48.90
Hydrogen Sulfide	mg/m^3	< 0.1	< 0.1	< 0.1	0.5	< 0.1	< 0.1
Total Sulfur	mg/m^3	3	2	2	3	2	2
tertiary-Butyl Mercaptan	mg/m^3	2.7	1.9	2.5	2.4	0.0	2.3
Tetrahydrothiopene	mg/m^3	4.7	3.2	4.3	4.2	4.9	4.0

		M	N	O	P	Q	R
Oxygen	mole%	< 0.02	< 0.02	< 0.02	< 0.02	< 0.02	
Nitrogen	mole%	0.94	0.77	0.77	0.77	0.85	
Carbon Dioxide	mole%	1.55	2.49	2.58	2.66	2.32	
Total inert gas	mole%	2.51	3.28	3.35	3.44	3.18	
Heating Value	MJ/m^3	38.38	38.36	38.37	38.40	38.23	
Wobbe Index	MJ/m^3	49.54	48.99	48.94	48.91	48.99	
Hydrogen Sulfide	mg/m^3	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1
Total Sulfur	mg/m^3	3	3	3	3	2	2
tertiary-Butyl Mercaptan	mg/m^3	1.6	2.6	2.7	2.6	1.7	0.7
Tetrahydrothiopene	mg/m^3	7.4	5.2	5.0	4.4	3.1	5.1

Sample Information

			GTS Sample ID	Date Sampled
A	Kilmore	Kilmore Hospital	UC-16-013	25/01/2016
B	Puckapunyal	Army Base	UC-16-014	25/01/2016
C	Seymour	Seymour Hospital	UC-16-030	26/01/2016
D	Euroa	Euroa tile	UC-16-029	25/01/2016
E	Benalla	D&R Henderson timber products	UC-16-028	26/01/2016
F	Wangaratta	2 Barry Ct	UC-16-027	26/01/2016
G	Wodonga	Vitasoy - Baranduda	UC-16-026	26/01/2016
H	Ettamogah	Norske Skog	UC-16-025	26/01/2016
I	Jindera	Boral Brick	UC-16-024	26/01/2016
J	Mulwala	Club Mulwala	UC-16-023	26/01/2016
K	Finley	Finley Hospital	UC-16-022	25/01/2016
L	Strathmerton	Bega factory	UC-16-020	25/01/2016
M	Numurkah	Riverland Oilseeds	UC-16-019	25/01/2016
N	Shepparton	Shepparton News	UC-16-015	25/01/2016
O	Stanhope	Fonterra	UC-16-016	25/01/2016
P	Kyabram	SPC Ardmona	UC-16-017	25/01/2016
Q	Moama	Moama Marketplace	UC-16-018	25/01/2016
R	Tocumwal	Bowls Club	UC-16-021	25/01/2016

Appendix E Excerpts of regulatory requirements.

Victoria - Gas Safety (Gas Quality) Regulations 2007

7 Odour

In addition to complying with the relevant standards referred to in regulation 6, gas must—

(a) have an odour which is distinctive and unpleasant; and

(b) have an odour level that is discernible at one-fifth of the lower explosive limit of the gas.

Victoria - Essential Services Commission – Gas Distribution Code

(e) except where the *Distributor* is prevented from so doing by *force majeure*, ensure that *gas* which meets the *prescribed standards of quality* when delivered into the *distribution system* at a *transfer point* also meets the *prescribed standards of quality* (including odorisation) when it is delivered to a *customer* at a *distribution supply point; and,*

Victoria - AEMO Gas Quality Standard

Acceptable Level	The preferred gas odorization is by way of a blend of 70% THT and 30% TBM injected into the gas stream at a rate of 7 mg/m^3 of gas. This gas odorization regime has traditionally been considered adequate to meet the requirements of the Victorian Gas Safety (Gas Quality) Regulations.

Victoria - AEMO Gas Quality Guidelines

PARAMETER/CHARACTERISTIC	GAS QUALITY STANDARD LIMIT
Required by Gas Safety (Gas Quality) Regulations 2007	
Wobbe Index Max	52.0 MJ/m³
Wobbe Index Min	46.0 MJ/m³
Oxygen Max	0.2 mol%
Hydrogen Sulphide Max	5.7 mg/m³
Total Sulphur Max (including odorant)	50 mg/m³
Water Dewpoint at Maximum Transmission Pressure Max	0 °C
Water content of gas Max (Based on 15,000 kPa)	73 mg/m³
Hydrocarbon Dewpoint Max	2.0 °C at 3500 kPa gauge
Total Inerts Max (including Oxygen)	7.0 mol%
Objectionable Constituents Max	Nil
Gas Odorisation	Odorisation at rates between 7 and 14 mg/m³ of a 70/30 blend of THT/TBM

NSW - Gas Supply (Safety and Network NSW)

6 Procedures for ensuring that gas is malodorous

A safety and operating plan must:

(a) identify the procedures to be implemented by the network operator to ensure that gas conveyed or supplied has a distinctive and unpleasant odour, and

(b) specify the odoriferous substances to be used, and

(c) specify the odour intensities.

Appendix F Typical NJEX XY odorant unit with 450 litre tank

Appendix G Odorant Estimate Details

[redacted]

Business Case – V95

Pressure Regulating Facilities – Isolation Valve

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	Michael Gallagher, *Engineering Manager*
Approved By	Andrew Foley, *General Manager Victorian Networks*

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	Isolation valves at pressure regulator facilities are required to enable the facility or sections of the facility's pipework to be isolated during emergencies. These valves are also used to isolate sections of pipework within the regulator facility to allow periodic maintenance. Australian Gas Networks Limited's (AGN's) routine preventative maintenance program, it has identified Three facilities that have seizing isolation valves (located at Norske Skug I/C, Thurgoona Dr. and Queens Wharf Rd); and Two facilities that have cast iron isolation valves, which are more susceptible to cracking than steel valves and could result in a leak at the regulation station (located at Lindrum Rd and Sycamore Rd). If these isolation valves are not replaced and an incident occurred that required the regulator to be shut down, then a seizing valve would hamper an expedient response. Either a specialist emergency repair crew would be required to mobilised or an alternative valve would need to closed. This increases the risk of a serious incident occurring or significant loss of supply to the network. In relation to the cast iron valves, an unplanned replacement of this type of valve would require a shutdown of the facility which could result in a supply interruption. It is for this reason that AGN's replacement policy requires cast iron valves to be replaced when identified. There are 3 regulator facilities which are affected by seizing valves (Norske Skug I/C, Thurgoona Dr. and Queens Wharf Rd). There are 2 regulator facilities which have cast iron valve on the outlet pipework (Lindrum Rd and Sycamore Rd). In the event of an incident requiring shut down of a regulator, a seizing valve would hamper an expedient response. Either a specialist emergency repair crew would be required to be mobilised or an alternative valve would need to be closed. This increases the risk of a serious incident occurring or significant loss of supply to the network. These valves are also used to isolate sections of pipework within the regulator facility to allow periodic maintenance. We are proposing to replace all the seized and cast iron valves present at the 5 identified locations.
Options Considered	The following options have been considered: 1 Option 1: Do nothing; or 2 Option 2: Replace the isolation valves at 5 regulator facilities.

Proposed Solution	Option 2 has been selected because it is the most cost effective way of managing the risks associated with seized and cast iron valves.
Estimated Cost	The forecast capital expenditure for this project is $286.3 ($000, 2016) over the next (2018 – 2022) Access Arrangement (AA) period.

Consistency with the National Gas Rules (NGR)	The proposal to replace isolation valves at 5 pressure regulating facilities complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because:
	• 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)); and
	• it is justified under rule 79(2)(c) as it is required to:
	  • to maintain and improve the safety of services (79(2)(c)(i));
	  • maintain the integrity of services (79(2)(c)(ii)); and
	  • comply with a regulatory obligation or commitment (79(2)(c)(iii)).

Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Safety theme as its implementation will allow AGN to maintain the safe supply of natural gas to customers by maintaining station valves in optimum condition to allow a quick, effective response to a potential incident More information detailing the results of the stakeholder engagement program is provided in Chapter 5 of the Access Arrangement Information document.

1.3. Background

Pressure regulating facilities have inlet and outlet valves, which enable the facility or sections of the facility's pipework to be isolated when required. Australian Standards AS2885.1 (Pipelines - Gas and Liquid petroleum) and AS4645.1 (Gas distribution network management) require transmission and distribution facilities to install and maintain isolation valves to allow for expedient isolation of the facility emergency and maintenance purposes The isolation valves in these facilities are key components of the City Gate pipework and are required to be operational for maintenance activities or emergency isolation and control purposes. If an emergency incident were to occur, these valves allow expedient shut down of a facility before a permanent repair can be completed.

Through its periodic preventative maintenance program, AGN has identified three pressure regulating facilities where the isolation valves are seizing. Seizing valves reduce the ability of AGN operations staff to maintain the regulating facility. Sections of the pipework cannot be isolated without correctly operating valves. If an emergency (eg a leak) were to occur at a regulating facility, a seized valve would inhibit an attempt to shut down and isolate the pipework to make the facility safe and begin repairs. Without correctly functioning valves, two other options would have to be considered for isolation:

- Shut down alternative isolations valves on the pipeline or network – The problem with this option is that it widens the group of customers that would be affected by the loss of supply because a wider area would be impacted.
- Mobilise a specialist emergency contractor – The problem with this option are that it costs a considerable amount to mobilise a contractor (>$100k), there is a time delay with mobilising contractors (minimum 24 hours) and it is also dependent on the availability of contractor crews and equipment.

- Two pressure regulating facilities that have cast iron outlet valves, which are more susceptible to cracking in the body of the valve and could result in a leak at the regulation station. An unplanned replacement of a cast iron valve would require a shutdown of the facility which could result in a supply interruption. It is for this reason that the AGN's replacement policy requires cast iron valves to be replaced when identified.

Table 1.3 provides further detail on the five regulator facilities.

Table 1.3: Regulator Facilities

Facility ID	Facility Name	Valve Issue	Replacement Valve
P4-117	Sycamore Rd HP Regulator	2 cast Iron outlet valves identified	2x Class 150 DN100 ball valves – steel body
P4-013	Lindrum Rd, field regulator	2 cast Iron outlet valves identified	2x Class 150 DN100 ball valves – steel body
N1-1619	Norske Skug I&C, Albury	1 seizing outlet valve identified	1x Class 300 DN150 ball valve outlet pipework
P4-150	Thurgoona Dr, Albury	2 seizing outlet valves identified	2x Class 150 DN100 ball valves on outlet pipework
P2-089	Queens Wharf Rd field regulator	1 seizing outlet valves identified	1x Class 150 DN200 ball valves on outlet pipework

1.4. Risk Assessment

A risk assessment has been carried out using APA's established evaluation criteria (detailed in Appendix A – Risk Assessment) to produce an estimated level of risk, which is summarised in Table 1.4. As this table highlights, the untreated risks associated with valves at the 5 facilities has been assessed as "High".

Table 1.4: Risk Rating

Risk Area	Untreated Risk Level
Health and Safety	High
Environment	Negligible
Operational	High
Customers	Low
Reputation	Low
Compliance	Moderate
Financial	Negligible
Untreated Risk Rating	**High**

The key risk is to health and safety (particularly the safety risk to the public). Maintenance and emergency response within the Victoria distribution network would be impeded if a valve was not operational when required. To control the leak within the facility, the inlet valve would need to be closed and the supply to the facility shut off.

Loss of gas supply to the local network is an additional risk. If the local network is not back fed from an additional supply point, a facility shutdown could result in a network outage. If this was to occur, it could result in AGN incurring relighting costs and may also result in Guaranteed Service Level payments if customers cannot be restored within 12 hours.

1.5. Options Considered

AGN has identified the following options to address the safety related risks outlined in section 1.4:

- Option 1: Do nothing; or
- Option 2: Replace the isolation valves at 5 regulator facilities

1.5.1. Option 1 – Do Nothing

The do nothing option in this case would see the periodic valve maintenance by System Operations personnel continue under the current scheduled preventative maintenance program. Under this option the seized valves would continue to be maintained under this program to the extent they can be.

1.5.1.1. Cost/Benefit Analysis

The benefit of this option is that it does not give rise to any upfront replacement costs. However, the health and safety and operational risks outlined in section 1.4 would continue to exist, with the untreated risk remaining high (see Appendix A).

1.5.2. Option 2 – Valve replacement program at 5 regulator facilities

This option entails the replacement of the identified isolation valves at the 5 pressure reduction facilities with approved specification valves.

1.5.2.1. Cost/Benefit Analysis

The benefits of this option are that:

- quick and effective isolation of the pipework within the facilities will be possible for maintenance or during an emergency; and
- the residual risk associated with the valves at these locations will be reduced from High to Moderate (see Appendix A).

The cost of replacing the identified valves at the 5 locations is estimated to be $286.3 ($000, 2016) (see section 1.7.3 for more detail). This cost is based on the actual costs AGN has incurred carrying out similar projects.

1.6. Summary of Cost/Benefit Analysis

A summary of the costs and benefits of the five options is shown in Table 1.5 below.

Table 1.5: Summary of Cost/Benefit Analysis

Option	Benefits	Costs/Risks
Option 1: Do nothing.	No upfront capital expenditure on new outlet valves	AGN would continue to incur the costs of checking pressure facility isolation valves as part of existing preventative maintenance costs. AGN would be unable to isolate the facility at these five locations, which means that a stoppling operation would be needed for planned maintenance or during an emergency incident. The risk of the cast iron valve cracking and causing an uncontrolled leak of gas will not be addressed.
Option 2: Isolation valve replacement program at 5 regulator facilities	Maintains pressure reduction facilities in optimum condition. Permits quick and effective isolation of pipework for maintenance or emergencies. Reduces the residual risk to Moderate.	Capex: $286.3 ($000, 2016)

1.7. Proposed Solution

1.7.1. What is the Proposed Solution?

The preferred option is to replace the identified valves at the 5 pressure reduction facilities (Option 2), which will occur over the next AA period.

1.7.2. Why are we Proposing this Solution?

AGN is proposing to implement Option 2 because it is the most cost-effective way of managing the risks associated with the seized and cast iron isolation valves and is consistent with the requirements set out in AS2885 and AS4645. Implementing this option will allow sections of the facilities pipework to be isolated in the event of a leak or for maintenance, which will, in turn, reduce the risks to public safety and the number of affected customers and allow scheduled maintenance to proceed without hindrance.

Option 1 is not being proposed, as it is inconsistent with the requirements of AS2885 and AS4645 and will not reduce the risk associated with these valves to as low as reasonably practicable (ALARP).

AGN has also taken into account the following factors in the selection of this solution:

- *Technical* – A replacement program addresses the issue of seizing and cast iron isolation valves. There is no other low cost solution which would address the issue. Any other solution would involve a complete rebuild of the facility and would be ordered of magnitude greater than valves replacement. This is not an option that a prudent operator would pursue.
- *Cost Effectiveness* – The replacement program is the only effective solution that addresses the issue of seized and cast iron valves. To not replace the valves would expose AGN to much higher costs in the event of an emergency incident. An emergency incident would require the mobilisation of a specialist emergency repair contractor with a minimum mobilisation time of

24 hours and the closure of alternative isolation valves. Closure of alternative isolation valves would affect a greater number of customers. It could also lead to relatively high rectification costs, given the costs associated with relighting and the potential for AGN to have to make Guaranteed Service Level payments if customers cannot be restored within 12 hours.

- *Project delivery* – This project will be delivered by December 2022. This will allow the program of works to coincide with other planned works at the pressure facilities. This allows an efficient use of resources which will be required to complete the works. The works will be completed using existing resources both internal and external labour.
- *Stakeholder feedback* - AGN has undertaken a comprehensive engagement program to better understand the values of stakeholders. During this engagement, stakeholders noted that they valued initiatives that improve the safety, reliability and customer service of the network. Consistent with these three insights, replacement of the identified valves will increase safety, increase reliability and reduce the number of customers affected if an incident occurred.

1.7.3. Forecast Cost Breakdown

The scope of works to replace the identified valves includes:

- *Design and Planning* – Detailed alteration designs will be required for each of the identified facilities. The design will need to meet all regulatory requirements and consent to construct and operate.
- *Procurement* – AGN will need to procure the specified valves using its approved supply panel. The panel contains pre-approved suppliers that have been selected through a competitive procurement process and ensures reduced procurement lead time and competitive pricing of materials.
- *Installation* – A mix of internal and external resources will be required to remove the existing valves and install the new valves. The replacement will occur during period of low gas demands or customer shut down periods. This will allow efficient use of resources and minimise operational risks.
- *Commissioning* – Once the valves are installed they will need to be commissioned by AGN operations personnel.
- *Change management* – Once the valves are commissioned the facility drawings will need to be updated to reflect changes. The Maximo asset management system will also need to be updated.

The replacement programme is intended to be completed by December 2022.

Tables 1.6 and 1.7 set out the forecast cost of carrying out this project, which is based on similar works that have recently been completed in AGN's South Australian network.

Table 1.6: Estimated Cost of Valve Replacements ($000, 2016)

Pressure Reduction Facility	Item	Cost
P4-117, Sycamore Rd	Design, Engineering & Planning	[redacted]
	Materials (2*Dn100 CI 150 and gaskets)	[redacted]
	Stoppling operation	[redacted]
	Installation and commissioning	[redacted]
	Traffic Management	[redacted]
Sub-Total		[redacted]
P4-013, Lindrum Rd	Design, Engineering & Planning	[redacted]
	Materials	[redacted]
	Stoppling operation	[redacted]
	Installation and commissioning	[redacted]
	Traffic Management	[redacted]
Sub-Total		[redacted]
N1-1619, Norske Skug IC	Design, Engineering & Planning	[redacted]
	Materials	[redacted]
	Installation and commissioning	[redacted]
Sub-Total		[redacted]
20P4-150, Thurgoona Dr	Design, Engineering & Planning	[redacted]
	Materials	[redacted]
	Stoppling operation	[redacted]
	Installation and commissioning	[redacted]
	Traffic Management	[redacted]
Sub-Total		[redacted]
P2-089, Queens Wharf Rd.	Design, Engineering & Planning	[redacted]
	Materials	[redacted]
	Stoppling operation	[redacted]
	Installation and commissioning	[redacted]
	Traffic Management	[redacted]
Sub-Total		[redacted]
Program Total		**286.3**

Table 1.7: Capex ($000, 2016)

	2018	2019	2020	2021	2022	Total
Material	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labour	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Design & Planning	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	**65.1**	**65.1**	**20**	**67.1**	**69**	**286.3**

1.7.4. Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN considers the forecast capex for this project to be:

- *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. Maintaining pressure reduction facilities is optimum condition for maintenance and emergencies is a necessary expenditure.
- *Efficient* – The valve replacement program will use existing internal and external labour resources that have extensive experience in completing this work in a safe and cost effective manner. The external labour will be obtained through a competitive tendering process, while materials will be sourced through AGN's procurement panel of suppliers, which has been established through a competitive procurement process. The expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.
- *Consistent with accepted and good industry practice* – Addressing the risks associated with the seizing/cast iron isolation valves 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 Standards AS4645 and AS2885.
- *To achieve the lowest sustainable cost of delivering pipeline services* – Replacing the seizing and cast iron isolation valves in a planned manner is the most cost effective solution and will result in a lower sustainable cost of delivering pipeline services over the longer term.

The capex can therefore be viewed as being consistent with rule 79(1)(a) of the NGR. The proposed capex is also consistent with rule 79(1)(b), because the expenditure is necessary to:

- *maintain and improve the safety of services (rule 79(2)(c)(i));* Maintenance and emergency response within the network would be impeded if a valve were not operational when required,
- *maintain the integrity of services (rule 79(2)(c)(ii));* and maintaining these vales minimises the impact of maintenance and emergency operations. If a valve were not operational when required, Isolations would need to be made at other locations, which would affect much larger parts of the network.

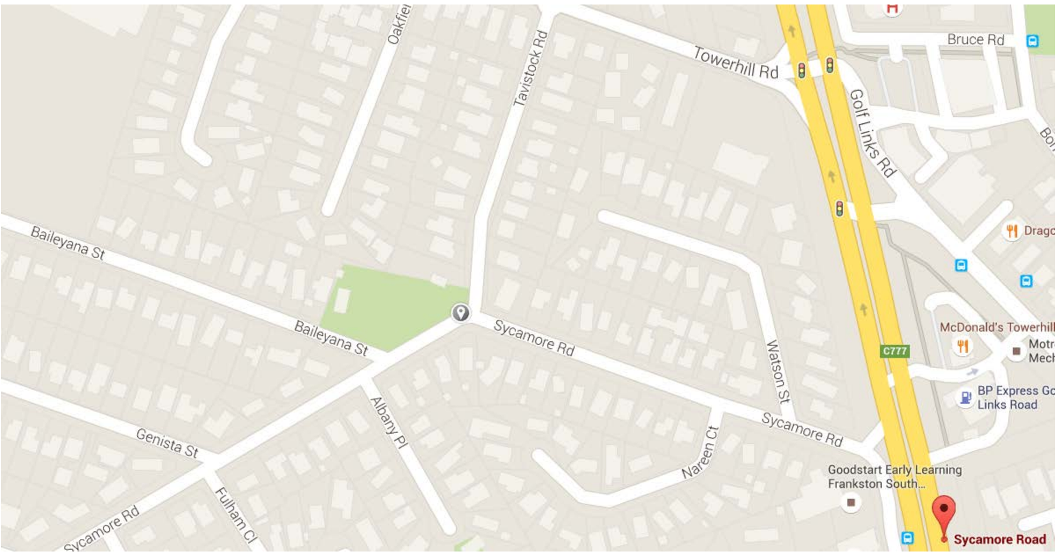
Appendix A Risk Assessment

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels
Risk Untreated + Option 1 - Do nothing	**Likelihood**	*Occasional*	*Unlikely*	*Occasional*	*Unlikely*	*Possible*	*Occasional*	*Unlikely*	
	Consequence	*Major*	*Insignificant*	*Minor*	*Insignificant*	*Minor*	*Medium*	*Insignificant*	
	Risk Level	*HIGH*	*Negligible*	*HIGH*	*Low*	*Low*	*Moderate*	*Negligible*	**HIGH**
	Likelihood	*Possible*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	
Residual Risk Option 2 Isolation valve replacement program	**Consequence**	*Medium*	*Insignificant*	*Insignificant*	*Insignificant*	*Insignificant*	*Major*	*Insignificant*	
	Risk Level	*Moderate*	*Negligible*	*Negligible*	*Negligible*	*Negligible*	*Low*	*Negligible*	*Moderate*

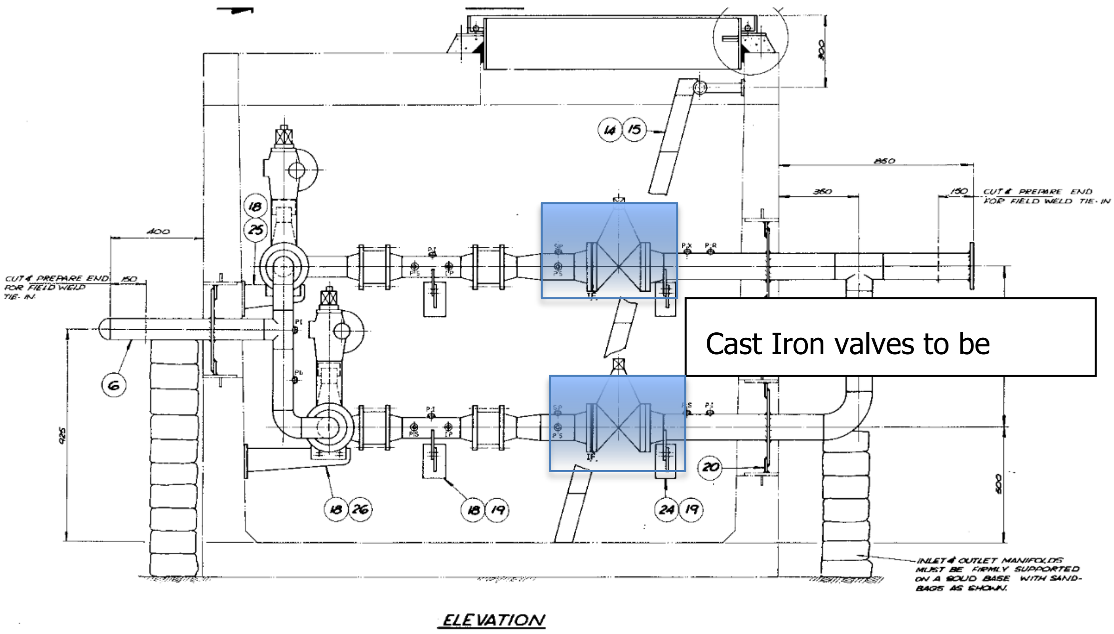
Appendix B P4-117 Sycamore Rd

Sycamore Rd field regulator was installed in 1980 to provide a supply to the Frankston high pressure distribution system.

Location: Corner of Sycamore Rd & Tavistock Rd, Frankston Vic



P4-117 regulator drawing:

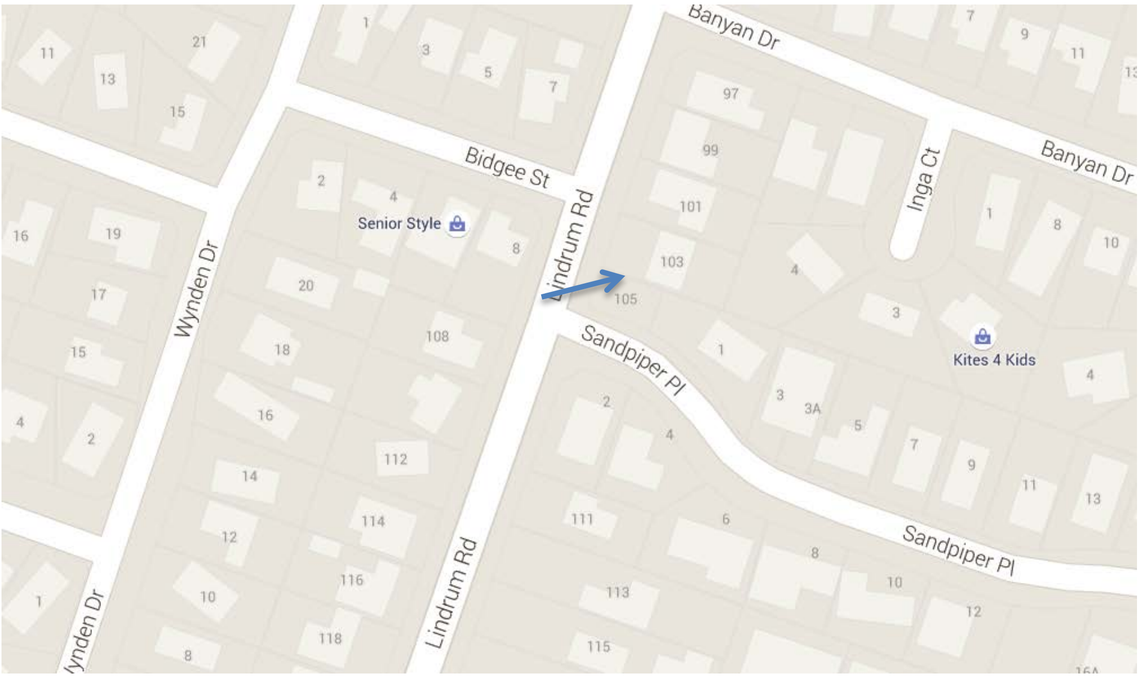


Estimate: P4-117

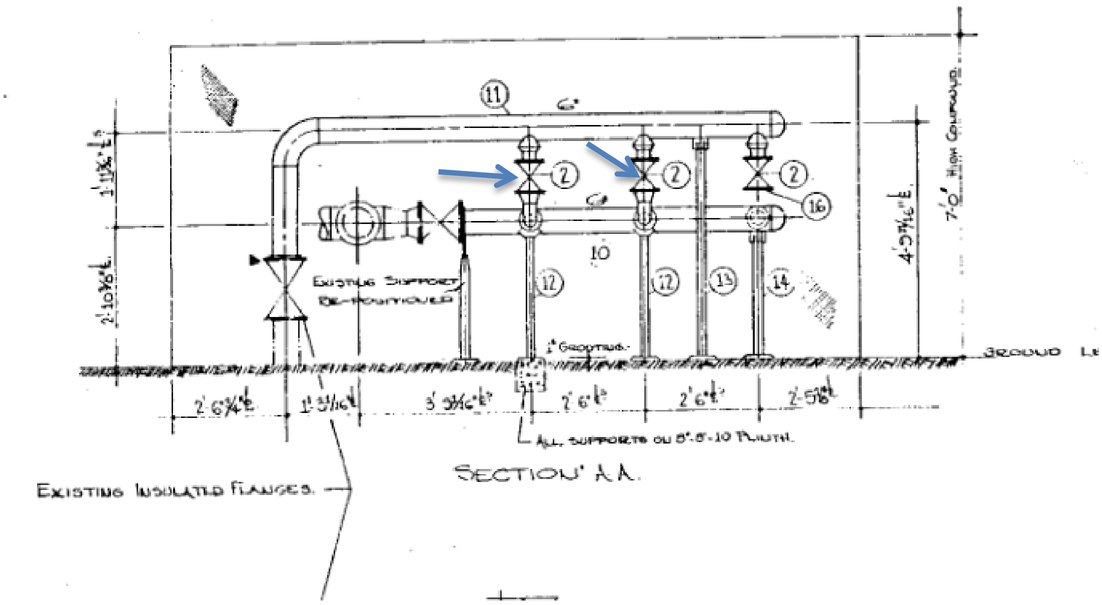
[redacted]

Appendix C P4-013, Lindrum Rd

Location: Corner of Lindrum Rd and Sandpiper Pl, Frankston, 3199



P4-013 drawing:

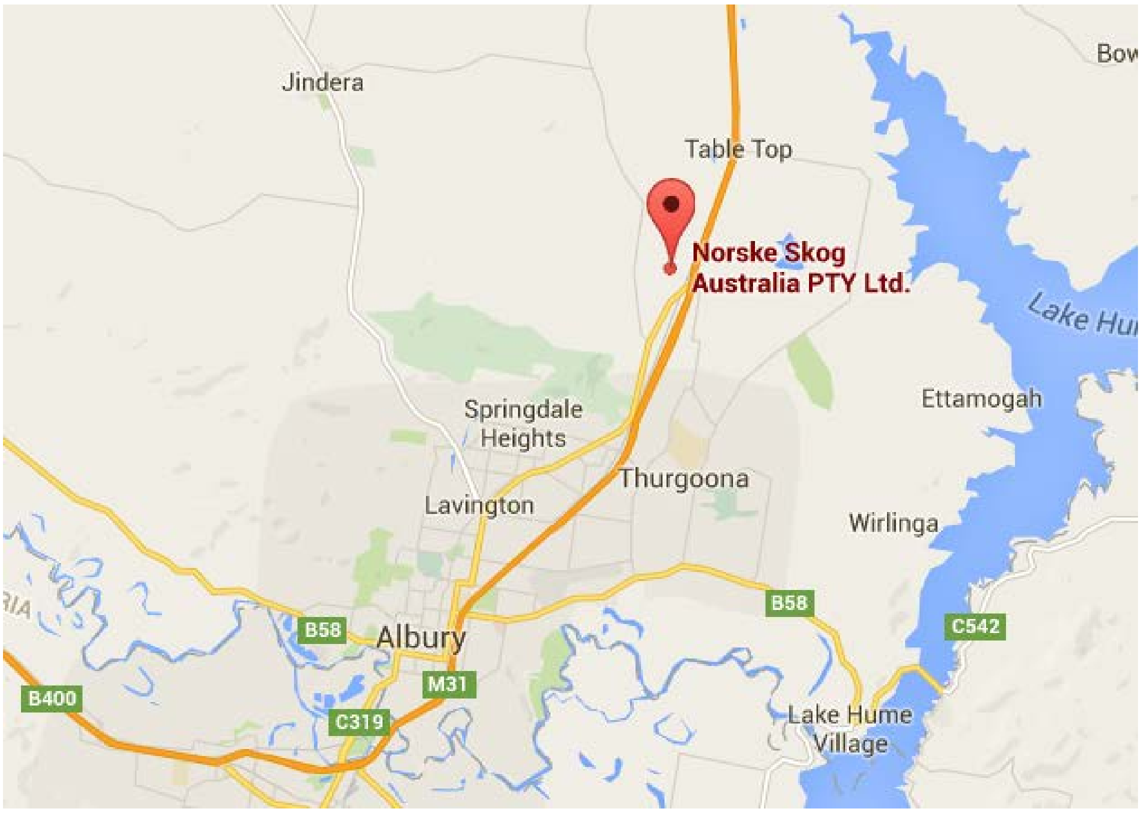


Estimate P4-013

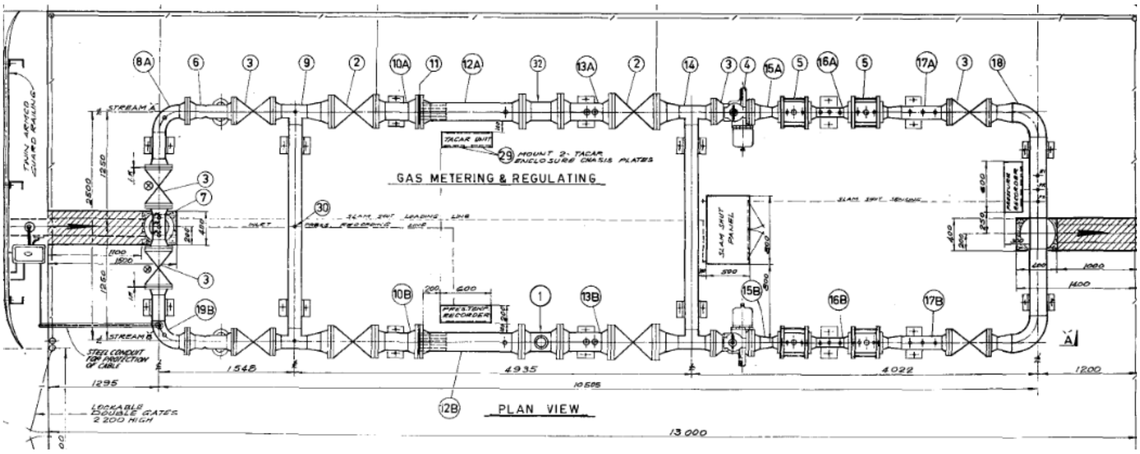
[redacted]

Appendix D N1-1619, Norske Skog Pty I&C

Location:



N1-1619 drawing:

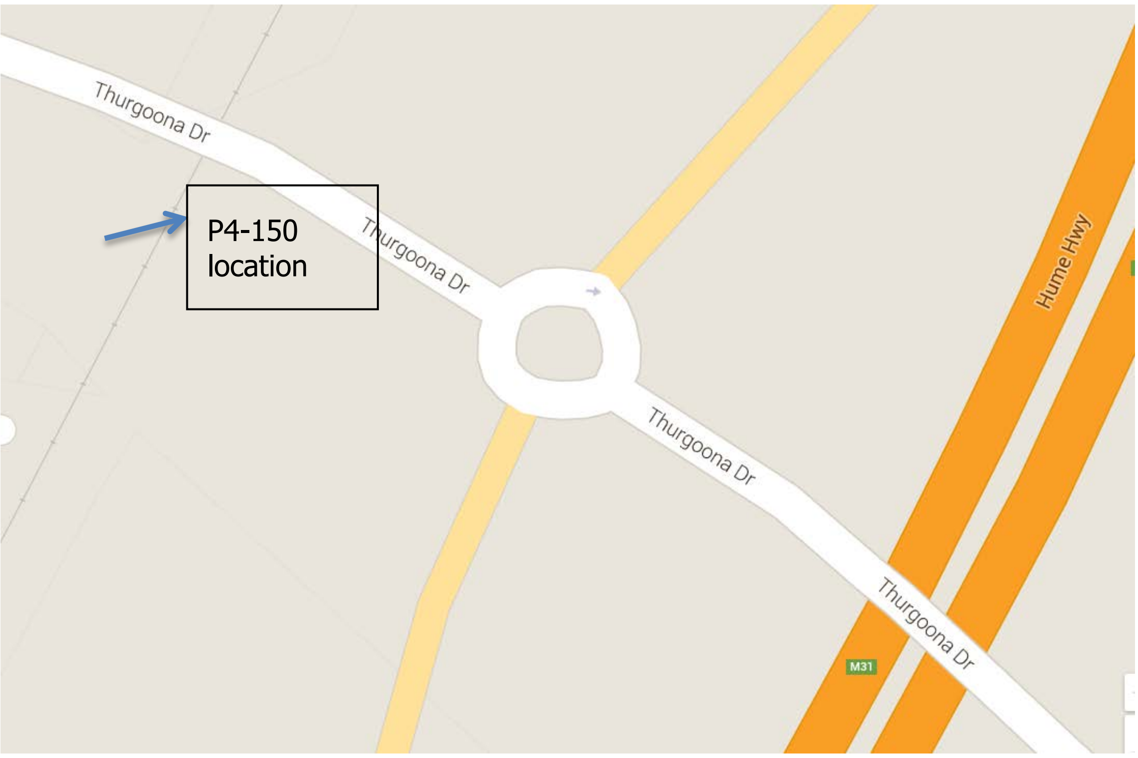


Estimate N1-1619

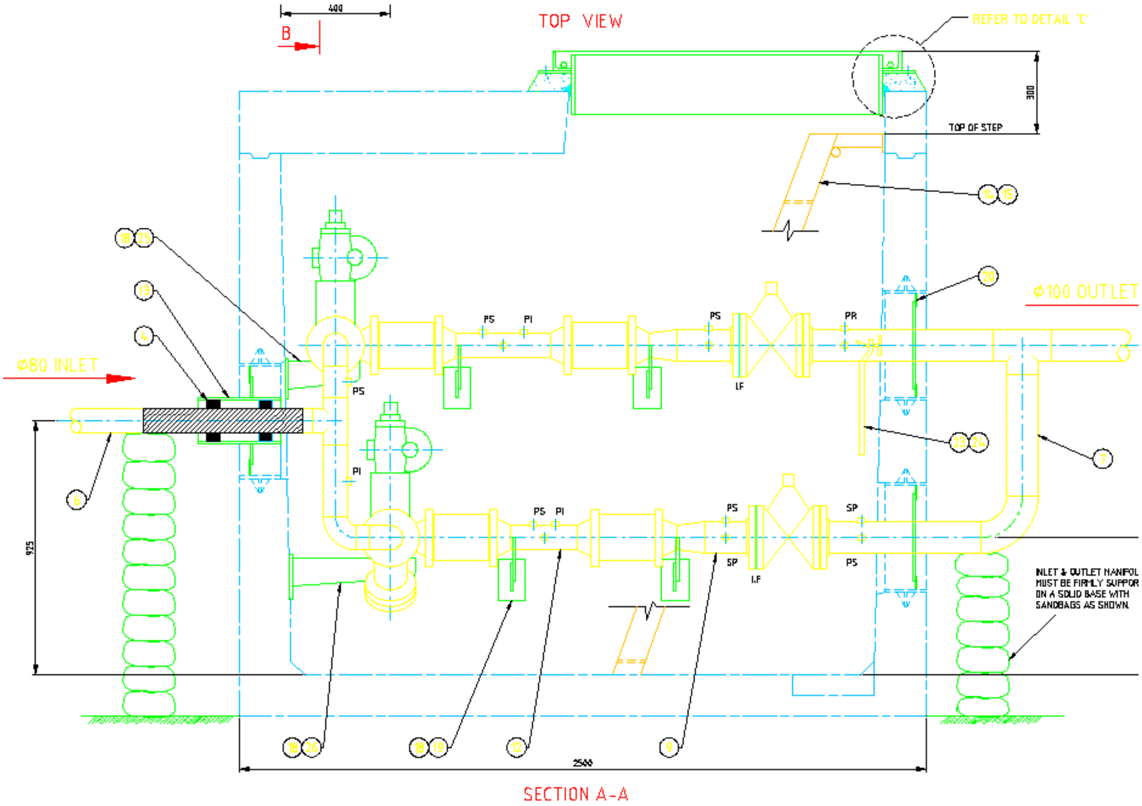
[redacted]

Appendix E P4-150, Thurgoona Drive, Albury, NSW

Location:



P4-150 drawing:

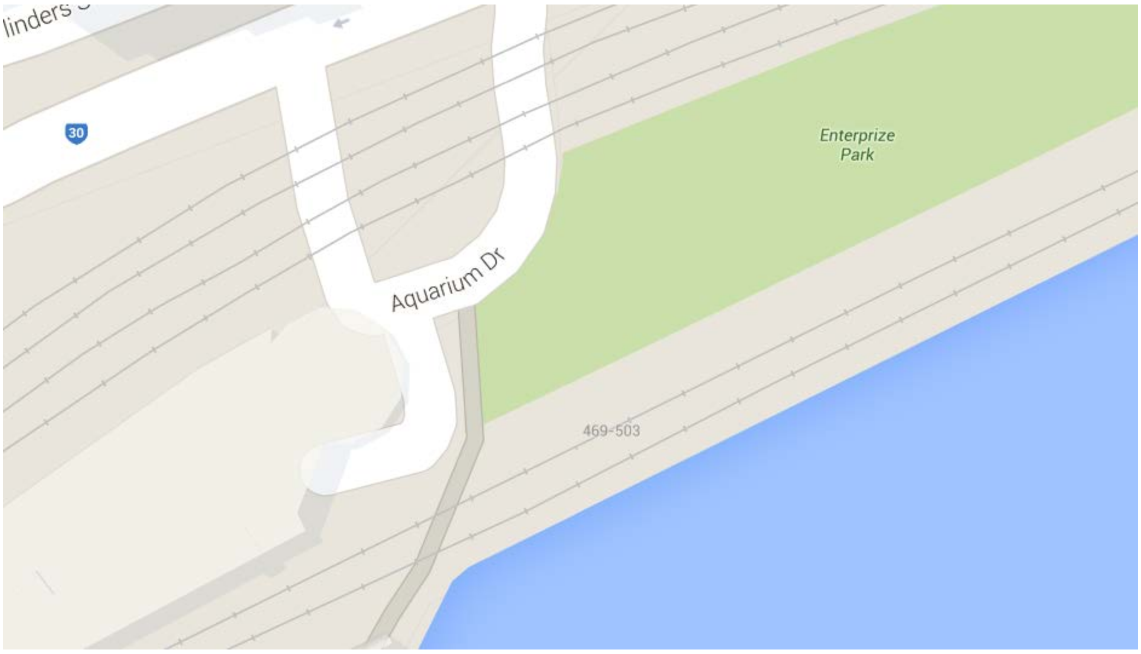


Estimate P4-150

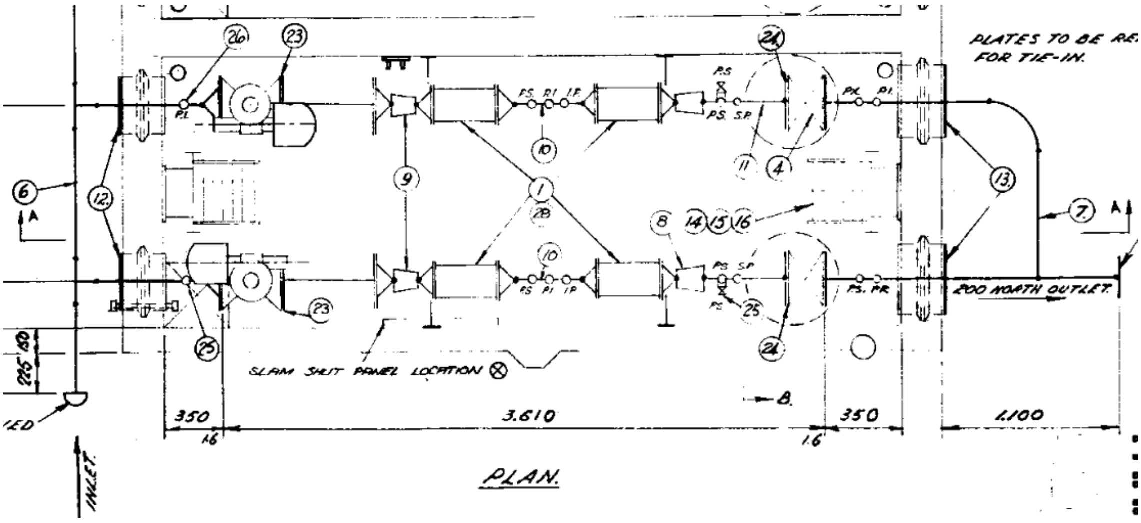
[redacted]

Appendix F P2-089, Queens Wharf Rd medium pressure regulator

Location:



P2-089 drawing:



Estimate P2-089

[redacted]

Telemetry Business Cases

Business Case	Capex Value ($2016)
V07 SCADA - End of Life Replacement	$0.4m
V08 SCADA - Field Regulators and Fringe Points	$0.7m
V53 Water Bath Heater Outlet Temperature Monitoring	$0.1m

Note: Supporting Information files have been provided separately.

Business Case – Capex V07

SCADA – End of Life Replacement

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	Ashweeen Prasad, *Supervisor System Monitoring*
Approved By	Andrew Foley, *General Manager Victorian Networks*

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	Australian Gas Networks Limited (AGN) has commenced a program to replace and upgrade degraded, corroded and non-compliant SCADA instruments at a number of field regulator and fringe network sites in regional areas of the Victorian and Albury networks. Work commenced on this program in the current (2013-2017) Access Arrangement (AA) period, but a further 24 field regulator sites will need to be replaced and upgraded in the next (2018-2022) AA period. The replacement and upgrade is required because the instruments have either degraded to such an extent there is damage to the internal equipment, or there is corrosion damage due to water ingress, with the result that the installation fails to comply with a number of aspects of AS/NZS 600791. Most of this equipment has reached the end of its useful life and is obsolete, requiring upgrade of glands, transmitter and at some sites a rewiring of the whole site. If this equipment continues to be used it will pose an occupational health and safety hazard for maintenance personnel as it no longer meets the required safety standards for electrical equipment in Hazardous Areas. By not replacing this equipment there also exists a risk of failure of the SCADA system with resultant risk of loss of control and monitoring of the pressures in the network, exposing AGN to potential loss of supply to customers. The successful solution of this project will ensure: • Upgrade of pressure and temperature transmitters, slam shut switches and pit entry security switches conforming to the relevant parts of AS/NZS 60079. • Upgrade of junction boxes and electrical rewiring to comply with AS/NZS3000:2007 Australian/New Zealand Wiring rules for Hazardous Area. • Real time SCADA monitoring of regulator supply pressures which provides a “health” check of these facilities, allowing timely diagnosis and rectification of equipment performance issues before problems arise. • Conformance to industry standards for electrical equipment in hazardous area installations. • Continued compliance by AGN with its regulatory obligation in the Gas Distribution System Code (Code) to use all reasonable endeavors to ensure minimum prescribed pressures are maintained at gas delivery points.[1] This project is a continuation of the existing replacement program approved by the AER in the current AA under V96 Field Assets Alterations and Replacements.[2]

[1] Gas Distribution System Code, Ver 11.0, p 40
[2] AER - Access arrangement final decision - Envestra - Part 2 - March 2013, Table 4.28

Options Considered	The following options have been considered: • Option 1 : Do Nothing • Option 2: Replacement of SCADA instrumentation at 24 regional network sites.
Proposed Solution	Option 2 has been selected because it is the most cost effective way to manage the risks associated with degraded, corroded and non-compliant SCADA instrumentation. It will also improve safety for operational staff by ensuring compliance with electrical standards for hazardous areas.
Estimated Cost	The proposed capital expenditure for Option 2 is $398 ($000, 2016).

Consistency with the National Gas Rules (NGR)	Replacement of degraded, corroded and non-compliant instrumentation at SCADA City Gate and Field Regulator sites complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because:
	• 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)); and
	• it is justified under 79(2)(c) as it is required to:
	  • maintain and improve the safety of services (79(2)(c)(i));
	  • maintain the integrity of services (79(2)(c)(ii)); and
	  • comply with a regulatory obligation or requirement (79(2)(c)(iii)).

Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Reliability and Safety themes as its implementation will allow AGN to maintain the safety of our network whilst continuing to provide a highly reliable supply of natural gas to our customers by ensuring that SCADA monitoring equipment is fit for purpose. More information detailing the results of the stakeholder engagement program is provided in Chapter 5 of the Access Arrangement Information document.

1.3. Background

Situations arise where gas network related assets, in this case SCADA instrumentation equipment, require replacement due to age, degradation caused by issues such as corrosion or to maintain compliance with current standards. Breakdown of such equipment can sometimes result in security of supply issues. Regular expenditure relating to the replacement of old, end-of-life and degraded or non-functioning equipment across a range of asset types is essential for the fit for purpose functioning of the network.

AGN's Victorian and Albury networks utilise SCADA equipment for the remote control and monitoring of critical pressures within the networks. Remote Terminal Units (RTUs) are an integral component of the SCADA system. Amongst its other functions, the SCADA system monitors the overpressure protection system, which is critical for the protection of lower pressure networks against overpressure from failed equipment in higher pressure networks.

An RTU is a device installed at a remote location that collects data, codes the data into a format that is transmittable and transmits the data back to a central station. Components within the field equipment require periodic replacement and upgrading to ensure correct functionality and to meet current electrical and hazardous area standards. These components include personnel protection circuits, valve motor replacements, electrical glands for hazardous areas, slam shut indicators, cable connections and transmitters.

AGN maintains the telemetry system through periodic maintenance. Details regarding the operation and integrity of the telemetry system at each site have been conveyed to the SCADA supervisor and have been captured as part of a desktop review. As per the results show in Appendix C, a number of sites in Northern and South-Eastern Victoria require replacement. If the SCADA components at these sites are not replaced, AGN may be unable to:

- Maintain effective and efficient control and monitoring of the pressure reduction stations (City Gates and Field Regulators); and
- Respond in a timely manner to emergencies, which could result in supply interruptions, or may not be able to control pressures within the network at optimum levels.

Operational personnel could also be at risk of injury as the hazardous rating of the electrical systems will not be effective.

AGN's ability to continue to meet its obligations under the Victorian Gas Distribution System Code (Code) and electrical industry standards would also be at risk in the event of a telemetry failure at a distribution supply point.

Viewed in this way it is clear that replacing and upgrading the electrical glands, slam shut indicators, tagging transmitters, cable connectors, personnel protection circuits, valve motor indicators of the SCADA system at the 24 sites is required to maintain the safety and integrity of services within the regional networks. It is also required to:

- Enable AGN to comply with the Gas Distribution System Code requirement to use all reasonable endeavours to maintain minimum pressures at distribution supply points.
- Provide for timely responses to emergencies from early warning (alarms) of potential loss of supply in the event of equipment malfunction or third party damage.
- Provide real time data to assist in producing optimum network augmentation designs including pressure control facilities.
- Improve safety for maintenance staff as a result of electrical equipment and wiring conforming to hazardous area specification.
- Provide for real time and optimum network pressure control, which will assist in minimising unaccounted for gas losses.

1.3.1. Continuation Project

This project was previously proposed and approved by AER in the current AA period as Business Case V96:[3]

> *"The AER considers that the following projects are justifiable under r. 79(2) of the NGR and would be incurred by a prudent and efficient distribution business acting in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services in accordance with r. 79(1)(a) of the NGR. The AER also considers these forecasts have been arrived at on a reasonable basis."*

Business Case V96 was a high level business case canvassing a broad, but unspecified, range of work within the distribution system that is necessary to ensure assets operate reliably, and asset integrity and continuity of supply to customers is maintained.

The AER approved $6.6 million over the term of the current AA period, based on historical expenditure for this type or work.

Due to other operational priorities, some of the work undertaken as part of V96 in the current AA period is the work now proposed separately under this business case V07 for the next AA period.

[3] AER - Access arrangement final decision - Envestra - Part 2 - March 2013, Table 4.28

1.4. Risk Assessment

A risk assessment has been carried out using APA's established evaluation criteria (detailed in Appendix A – Risk Assessment) to produce an estimated level of risk, the results of which are summarised in Table 1.3.

As this table shows, the risk associated with the failure of electrical equipment and non-conformance of electrical equipment used within hazardous area within AGN SCADA monitoring and control to regional areas has been assessed as "High".

Table 1.3: Risk Rating

Risk Area	Untreated Risk Level
Health and Safety	Moderate
Environment	Moderate
Operational	Moderate
Customers	Moderate
Reputation	Moderate
Compliance	Moderate
Financial	Moderate
Untreated Risk Rating	**High**

If the risks associated with not upgrading obsolete and non-compliant SCADA equipment in regional and metro areas are left untreated, it is possible AGN may not always be able to respond in a timely manner to emergencies resulting in future supply interruptions, and/or be unable to monitor and control pressure on a real time basis to maintain and improve safety of services and integrity of services.

Pressure deviations at City Gate or Field Regulator sites, either high or low will not be identified. The main risk here is either an equipment malfunction resulting in either over-pressurising the network or inadequate gas supply to the network, or general network load growth exceeding the regulator's capacity resulting in inadequate gas supply or damage to assets. This would result in GSL payments to customers in the order of $1,500,000.00 in the event of not responding in time to an outage impacting on approximately 10,000 customers.

- *Safety* – Electrical equipment for use in hazardous areas is designed to contain any ignition point within the equipment itself. Damage to the seals or the equipment case (as a result of the identified corrosion at the proposed sites) can compromise the flame path and result in an ignition source entering the hazardous area within the case, causing a safety issue for maintenance personnel and consequently the general public.
- *Compliance* – Some of the existing installations do not comply with the current hazardous area standards which could result in a non-conformance from the regulator Energy Safe Victoria.

1.5. Options Considered

AGN has identified the following options to address the risks outlined in section 1.4:

- Option 1: Do nothing; or

- Option 2: Continue the SCADA replacement program at 24 regional network sites over a 5 year period.

1.5.1. Option 1 – Do Nothing

Under this option AGN will cease its current program of replacing the degraded SCADA equipment at regional sites and will instead just monitoring the equipment on a yearly basis as part of the current preventive maintenance program. If the capex approved in the current AA period is not continued to be provided, failed equipment will either not be repaired or other capex programs will suffer due to the need for the work to be undertaken in order to provide a safe workplace by compliance with hazardous area standards.

1.5.1.1. Cost/Benefit Analysis

The only benefit of this option is that there are no upfront capital costs. This option is not, however, costless because AGN will continue to incur costs through the preventative maintenance program and through a reactive upgrade program if electrical components fail the annual preventative maintenance checklist or if operator complaints are received of incorrect network asset pressure levels or valve status. AGN will also be exposed to the following costs and risks:

- Equipment failing to meet electrical standards for hazardous areas potentially resulting in injuries to personnel and penalties from regulatory bodies.
- This approach at City Gate and Field Regulator sites could risk:
  - failure of components resulting in incorrect data; or
  - the network system running in Failsafe mode (resulting in High Pressures within the network and higher Unaccounted for Gas UAFG).
- AGN's ability to efficiently plan and complete network capacity management projects in a timely manner in regional areas will be limited by not maintaining an operational ability to supervise and/or control network pressures.
- By not replacing components, control of the Field Regulator assets will not be possible when the instrumentation fails, including the overpressure protection system which is critical for the protection of lower pressure the networks against overpressure from failed equipment in higher pressure networks.

The residual risk associated with this option has been assessed as being High (see Appendix A).

1.5.2. Option 2 – Replacement program

This option will see the program for replacing pressure and temperature transmitter components, limit switches and security switches to enhance SCADA monitoring and control facilities for regional and metropolitan networks that was approved for the current AA period continuing into the next AA period. For the next AA period replacement of instrumentation equipment at 24 sites over a 4 year period at a rate of 6 per annum is proposed. A rate of 6 sites per annum is consistent with the annual number installed over the last four years.

Appendix C provides a list of those sites proposed for this business case.

1.5.2.1. Cost/Benefit Analysis

The cost of this option is estimated to be $398.28 ($000, 2016), which translates to an average of $16.68 ($000, 2016) per site.

This option has the following benefits:

- Increased safety for maintenance staff as a result of electrical equipment and wiring conforming to hazardous area specifications.
- Timely responses to emergencies from early warning (alarms) of potential loss of supply in the event of equipment malfunction or third party damage.
- Continued integrity of monitoring overpressure protection equipment to ensure alarms are activated when this equipment operates, threatening supply at lower pressure networks.
- The availability of real time data to assist in producing optimum network augmentation designs, including operation of pressure control facilities to defer physical augmentation.
- Real time and optimum network pressure control which responds to load profiles in the network and will assist in minimising unaccounted for gas losses.
- It will assist AGN continue to meet its obligations under the Code (e.g. provision of minimum network pressures and Guaranteed Service Levels), compliance with which is a condition of AGN's Distribution Licence.
- The residual risk associated with the 24 sites will be reduced from High to Moderate (see Appendix A).

1.6. Summary of Cost/Benefit Analysis

A summary of the costs and benefits of the two options is shown in Table 1.4 below.

Table 1.4: Summary of Cost/Benefit Analysis

Option	Benefits	Costs/Risks
Option 1 – Do nothing	No upfront capex costs	Risks of non-compliance with the Code, increased levels of poor pressures, increased loss of supply incidents and customer complaints. Residual risk High.
Option 2 – Replace / Upgrade program for SCADA components regional and metro sites	Increased safety for maintenance staff as a result of electrical equipment and wiring conforming to hazardous area specification. Ability to monitor or operate the system remotely, control or manage pressures at optimum levels and the ability to provide timely responses to emergencies and unplanned supply interruptions. Assist in producing optimum network augmentation designs, including operation of pressure control facilities to defer physical augmentation. Assist AGN to meet its obligations for minimum network pressures and Guaranteed Service Levels as prescribed in the Code. Continued compliance with the Hazardous Area Code. Residual risk falls from High to Moderate.	$398 ($000, 2016) over four years of the next AA period (24 sites).

1.7. Proposed Solution

1.7.1. What is the Proposed Solution?

The proposed solution is Option 2, which will involve the continued replacement of obsolete or faulty components of SCADA network that do not meet the criteria in the yearly preventative maintenance schedules, or fail to meet safety standards for hazardous areas. In total 24 sites will be upgraded over 4 years of the next AA period, at 6 sites per year.

1.7.2. Why are we Proposing this Solution?

The key drivers for the recommended proposal to replace SCADA instrumentation equipment in regional areas are:

- Increased safety for maintenance staff as a result of electrical equipment and wiring complying with hazardous area specifications.
- It will assist AGN continue to meet its License obligations (e.g. provision of minimum network pressures and Guaranteed Service Levels) as prescribed in the Code.
- Timely responses to emergencies will result from early warning (alarms) of potential loss of supply in the event of equipment malfunction or third party damage to network assets. Real time system information is critical to maintaining supply as well as system integrity. This includes the integrity of monitoring overpressure protection equipment to ensure alarms are activated when this equipment operates, threatening supply at lower pressure networks.
- The availability of real time data will assist in producing optimum network augmentation designs including operation of pressure control facilities to defer physical augmentation.
- Real time and optimum network pressure control which responds to load profiles in the network and will assist in minimising unaccounted for gas losses.
- Site security for remote critical sites will be enhanced by the continued ability to centrally monitor site security entry alarms part of the SCADA capability.
- To ensure compliance with the electrical standards for hazardous areas.

The project is also consistent with the findings from the stakeholder engagement program in which customers indicated that they value the current standard of reliability and are supportive of initiatives that maintain that reliability, and also the safety of the network.

1.7.3. Forecast Cost Breakdown

Table 1.5 below shows the estimated project costs over the term of the AA period. The forecast in this table is based on the average cost of $15.72 ($000, 2016) per site for 24 sites undertaken to date during the current AA period (refer to Appendix E for details) and involves a mix of specialist direct labour and competitively tendered contract resources.

A revised estimate has been undertaken, in which the average costs for a typical site upgrade is estimated to.be $16.6 ($000, 2016). This is shown in Appendix D. While the historical costs have resulted in an average cost per site of $15.72 ($000, 2016), to be prudent, the revised estimate of current costs has been used in this business case. The increase in average cost is due to a high volume of regional sites that require additional accommodation and travel costs.

Table 1.5: Project Cost Estimate ($000, 2016)

	2018	2019	2020	2021	2022	Total
Volume	6	6	6	6	-	24
Unit Cost	16.59	16.59	16.59	16.59	-	
Total	**99.5**	**99.5**	**99.5**	**99.5**	**-**	**398.3**

1.7.3.1. Delivery of Proposed Solution

The current AA period will see an estimated 24 sites completed over 4 years at an average of 6 sites per year and AGN proposes to continue installing 6 per year for the first 4 years of the next AA period.

1.7.4. Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN considers the forecast capex for this project to be:

- *Prudent* – The expenditure is necessary in order to maintain the SCADA system to provide control and monitoring of the pressure reduction stations. It is also the most cost effective way of dealing with the issues that have been identified at the 24 sites and is therefore of a nature that a prudent service provider would incur.
- *Efficient* – The labour and material cost estimates for this project are based on actual costs incurred in the current AA period where SCADA components have been upgraded or replaced, which have been procured through competitive procurement processes and can therefore be assumed to be efficient. The forecast expenditure can also be expected to derive further efficiencies because the ability to maintain minimum supply pressures will enable AGN to monitor and control pressures on a real time basis. Less consumer calls or complaints of poor pressures can be anticipated, and maintaining the ability to control pressures to lower the overall pressure in the network will contribute to minimising UAFG.
- *Consistent with accepted good industry practice* – Good industry practice requires compliance with Australian standards and regulatory requirements. This project will ensure that the SCADA instrumentation equipment is compliant with AS/NZS 60079, and will also enable AGN to meet its obligations under the Code to use all reasonable endeavours to ensure that the minimum pressure is maintained at distribution supply points by ensuring the continuity of electronic data that monitors these pressures.
- *Achieves the lowest sustainable cost of delivering pipeline services* – The proposed project will assist in maintaining the operating integrity of City Gates and Field Regulators, which in turn contributes towards achieving the lowest sustainable cost of delivering the reference service. An effective SCADA allows remote operation and control, reducing the requirement for onsite response to maintain the network.

The capex can therefore be viewed as being consistent with rule 79(1)(a) of the NGR. The proposed capex is also consistent with Rule 79(1)(b), because the expenditure is necessary to:

- *maintain and improve the safety of services (rule 79(2)(c)(i))*; A well maintained telemetry system will ensure real time monitoring of AGN's critical assets enabling quick and accurate problem diagnosis of network issues resulting in reduced customer outages or a reduction in the likelihood in over pressuring the network. Given that some of the existing installations do not comply with the current standards, there is a safety risk to personnel working in hazardous areas with electrical equipment that has the potential to produce a spark.

- *maintain the integrity of services (rule 79(2)(c)(ii))*; and As mentioned above, a well maintained telemetry system will ensure real time monitoring of AGN's critical assets and reduces the likelihood of an overpressure on the distribution network which could cause significant network damage.
- *comply with a regulatory obligation or requirement (rule 79(2)(c)(iii))*; The replacement and upgrade is required because the instruments have either degraded to such an extent there is damage to the internal equipment, or there is corrosion damage due to water ingress, with the result that the installation fails to comply with a number of aspects of AS/NZS 60079.

Appendix A Risk Assessment

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Option Risk
Risk Untreated	**Likelihood**	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*High*
	Consequence	*Major*	*Medium*	*Medium*	*Medium*	*Major*	*Major*	*Major*	
	Risk Level	*High*	*Moderate*	*Moderate*	*Moderate*	*High*	*High*	*High*	
Residual Risk Option 1	**Likelihood**	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*High*
	Consequence	*Major*	*Medium*	*Medium*	*Medium*	*Major*	*Major*	*Major*	
	Risk Level	*High*	*Moderate*	*Moderate*	*Moderate*	*High*	*High*	*High*	
Residual Risk Option 2	**Likelihood**	*Rare*	*Rare*	*Rare*	*Rare*	*Unlikely*	*Unlikely*	*Rare*	*Moderate*
	Consequence	*Major*	*Medium*	*Medium*	*Medium*	*Minor*	*Minor*	*Medium*	
	Risk Level	*Moderate*	*Low*	*Low*	*Low*	*Low*	*Low*	*Low*	

Appendix B Pictures of Typical Degraded and Non-compliant Installations

Figure B.1 – Painted switch – non-compliant

Figure B.2 – Corroded equipment unable to be opened

Figure B.3 – Non-certified electrical equipment – non-compliant

Appendix C Hazardous Area Sites Proposed for 2018-22 AA period

Site	Hazardous Area Upgrade	Estimated Cost to Upgrade (Includes material, Labour, Accommodation)
DAWSON ST	Planned 2018	$15,280
JOHN ST	Planned 2018	$15,280
AUSTIN HOSPITAL	Planned 2018	$15,280
BANGALAY AVE	Planned 2018	$15,280
CHILTERN CITY GATE	Planned 2018	$15,280
DANDENONG TS Origin.	Planned 2018	$15,280
ECHUCA CG	Planned 2019	$17,380*
EUROA CITY GATE	Planned 2019	$17,380*
HODDLE ST	Planned 2019	$15,280
KYABRAM CG	Planned 2019	$17,380*
MERRIGUM CITY GATE	Planned 2019	$17,380*
MONSBENT	Planned 2019	$17,380*
NORSKE SKOG	Planned 2020	$17,380*
NORTH ST ALBURY	Planned 2020	$17,380*
RICHMOND OUTSTATIONS	Planned 2020	$15,280
RUTHERGLEN CITY GATE	Planned 2020	$17,380*
SHEPPARTON CITY GATE	Planned 2020	$17,380*
TATURA CITY GATE	Planned 2020	$17,380*
TONGALA CITY GATE	Planned 2021	$17,380*
TRARALGON CG	Planned 2021	$17,380*
WANGARATTA	Planned 2021	$17,380*
WANGARATTA EAST CG	Planned 2021	$17,380*
WEST MELBOURNE	Planned 2021	$17,380*
WODONGA CITY GATE	Planned 2021	$17,380*

Increased cost for these sites due to the need for travel and accommodation to reach regional sites.

Appendix D Detailed Cost Estimate per Site

Estimated installation cost for a typical Hazardous area upgrade of Regional and Metro SCADA sites is shown in the table below. Parts cost from Store catalogue.

Parts	Hazardous Area Upgrade Costing
Gas Pressure Transmitter	[redacted]
Gas Temperature Transmitter	[redacted]
Slam Shut Switches	[redacted]
Pit Entry Switches	[redacted]
Tube Fittings	[redacted]
RCD/MCB	[redacted]
Enclosure	[redacted]
Socket Outlet	[redacted]
Mounting Block	[redacted]
Fuses, Terminals, Wire	[redacted]
Earth Stack	[redacted]
Cable Glands	[redacted]
Total Parts	[redacted]
Labour	
Labour External - Contractor (24 Hrs X $100 / Hr)	[redacted]
Internal Labour RTU/SCADA (Wiring of RTU, Site installation including transmitters, commissioning and completion of Dossier (2 X E&I Technicians: 76 Hr X $72 / Hr)	[redacted]
Project Management and Administration (16 HRS X $80 / Hr)	[redacted]
Total Labour	[redacted]
Total Parts & Labour	[redacted]
Accommodation for Regional Sites	
2 technicians 3 nights' accommodation each - (6 nights X $350/night)	[redacted]
Total Parts & Labour & Accommodation	[redacted]

Note that 58% or 14 of the 24 sites planned for installation in the next AA period require overnight stay due to the remoteness of these sites. Taking this into account, the average cost per site is estimated to be $16,595.

Appendix E Cost per Site in the Current AA period

Sites Installed to March 2016

Site	Hazardous Area Upgrade	Estimated Cost to Upgrade (Includes material, Labour, Accommodation)
BENALLA CITY GATE	Completed 2013	$17,380
KLAUER ST	Completed 2013	$15,280
YARRAGON CG	Completed 2013	$15,280
CRANBOURNE RD	Completed 2013	$15,280
FIRMANS LANE	Completed 2013	$17,380
FITZSIMMONS LANE NORTH	Completed 2013	$15,280
HALL RD	Completed 2014	$15,280
KILMORE CITY GATE	Completed 2014	$15,280
KOONOOMOO CG	Completed 2014	$17,380
LINDRUM RD	Completed 2014	$15,280
PARK & BENNETT ST	Completed 2014	$15,280
ROSEDALE CITY GATE	Completed 2014	$17,380
SALE CG	Completed 2015	$17,380
ALMA RD	Completed 2015	$15,280
BERWICK CG	Completed 2015	$15,280
CHAFFEY DVE	Completed 2015	$15,280
DARNUM CG	Completed 2015	$15,280
HEALESVILLE CG	Completed 2015	$15,280
HUON PK RD	Completed 2016	$15,280
KEON PARK	Completed 2016	$15,280
SYCAMORE ST	Completed 2016	$15,280
TALLAROOK	Completed 2016	$15,280
WATSONIA RD & IBBOTSON	Completed 2016	$15,280
YALLAMBIE RD	Completed 2016	$15,280

Average Cost = $15,718 per site

Sites planned: April 2016 - June 2017

Site	Hazardous Area Upgrade	Estimated Cost to Upgrade (Includes material, Labour, Accommodation)
WEST MELBOURE	Planned 2017	$15,280
QUEENSWHARF RD	Planned 2017	$15,280
RAINIER AVENUE	Planned 2017	$15,280
PARK STREET EAST	Planned 2017	$15,280
BAYVIEW ROAD	Planned 2017	$15,280
RICHMOND OUTSTATION	Planned 2017	$15,280

Business Case – Capex V08

SCADA – Field Regulators and Fringe Points

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	Jarrod Dunn, *Manager - Operations*
Approved By	Andrew Foley, *General Manager Victorian Networks*

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	There are a number of Field Regulators and network fringe sites in Australian Gas Networks Limited's (AGN's) Victorian and Albury networks that do not have SCADA monitoring equipment. It is not possible therefore to monitor pressures at these sites on an ongoing basis, which gives rise to a range of costs and risks. Installing SCADA equipment at these sites will address these risks, providing for: • Real time SCADA monitoring of regulator supply pressures to provide a "health" check of these facilities allowing timely diagnosis and rectification of equipment performance issues before problems arise. • Timely alerts that the equipment is not working to specification • SCADA infrastructure that will facilitate future installation of pressure control equipment, when justified, to assist in operating the networks at optimum pressure levels • Monitoring to ensure that minimum pressures are maintained at the distribution supply point. The addition of fringe sites more distant from Melbourne will also provide: • for the maintenance of the delivery pressure of gas from the distribution system to ensure that the minimum supply pressure is maintained at distribution supply points, fringe points and the outlet of the meter; • guidance for the settings of regulator outlet pressure; and • allow AGN to meet its regulatory obligation under the Gas Distribution System Code (Code) to use all reasonable endeavors to ensure minimum prescribed pressures are maintained at gas delivery points[1] An equivalent project was approved by AER for the current (2013-2017) Access Arrangement (AA) period[2] for $200,000 per year ($1 million over the AA period) for installation of SCADA at 57 sites. By the end of the current AA period there will still be 63 locations that require this equipment.
Options Considered	The following options have been considered:

1 Gas Distribution System Code, Version 11, Schedule 1 Part A.
2 Business Case VA02

	1 Option 1: Do Nothing **2** Option 2: Install SCADA monitoring facilities at 30 Field Regulators and network fringe points. An option to complete all 63 sites in the next (2018-2022) AA period was also considered, but deliverability of this solution was considered to be problematic because it would require doubling the number of sites installed per year over the previous AA period, which is a significant step change. This option was not therefore considered any further.
Proposed Solution	The proposed solution is Option 2 because it is the most cost effective way to manage the risks at regional sites that do not currently have SCADA equipment. It will also provide for: • More timely response to emergencies • Real time data for optimum network augmentation design. • More cost effective and responsive monitoring because it eliminates the need to undertake periodic programs of on-site data logging, • Increased safety for operational staff by reducing the need for operators to work in a confined space environment for assets located in underground pits. • AGN to comply with the Code requirement to use all reasonable endeavours to maintain minimum pressures at distribution supply points
Estimated Cost	The forecast capital expenditure over the next Access Arrangement for Option 2 is $709.5 ($000, 2016).

Consistency with the National Gas Rules (NGR)	Installing SCADA at regional towns and network fringe points complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because:
	• 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)); and
	• it is justified under rule 79(2)(c) as it is required to:
	  ◦ maintain and improve the safety of services (79(2)(c)(i));
	  ◦ maintain the integrity of services (79(2)(c)(ii)); and
	  ◦ comply with a regulatory obligation or commitment (79(2)(c)(iii)).

Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Reliability and Safety themes as its implementation will allow AGN to improve the safety of our network whilst continuing to provide a highly reliable supply of natural gas to customers by augmenting the remote pressure monitoring capability of the AGN networks. More information detailing the results of the stakeholder engagement program is provided in Chapter 5 of the Access Arrangement Information document.

1.3 Background

Real time pressure monitoring of AGN networks via a SCADA system is a key part of AGNs management and operation of the network performance. Pressure monitoring at gas delivery points and at network fringes provides ongoing information about network gas delivery performance, network demand growth, and any emerging incidents that impact gas supply.

The inability to remotely monitor pressure at the Field Regulator sites without a connection to SCADA limits the ability to provide timely responses to emergencies and unplanned supply interruptions. Installing SCADA at these sites, along with fringe point (network extremity) pressure monitoring, will provide real time tools which will enable a more responsive and lower risk operation of these networks.

It will also provide real time data and a history of performance which will help to optimise the timing, scale and design of network augmentation. Under the Victorian Distribution System Code (Code[3]), AGN has a regulatory obligation to use all reasonable endeavours to:

> *"ensure the minimum pressure is maintained at the distribution supply point".*[4]

Installation of SCADA pressure monitoring is a "reasonable endeavor" that assists with meeting this obligation.

Improvements in communications technology (wireless) have made the monitoring of more distant sites easier to achieve and more cost effective than in previous years. This facilitates closer monitoring of all sites irrespective of their location and AGN wishes to continue to take advantage of the benefits offered in rolling out SCADA capability to the identified sites. Appendix C provides examples of where real time SCADA data would have provided enhanced response to gas supply incidents.

AGN has identified 63 Field Regulator and network fringe sites in the Victorian and Albury networks that would benefit from the installation of SCADA monitoring equipment, of which 30 are expected to be installed in the upcoming Access Arrangement Period (AA period) and the remaining 33 in the subsequent AA period (see Appendix D for a list of those sites proposed for this business case).

Installing SCADA equipment at these sites is required to maintain the safety and integrity of services within the regional networks. It is also required to:

- Enable AGN to comply with the Code requirement to use all reasonable endeavours to maintain minimum pressures at distribution supply points.
- Provide for timely responses to emergencies from early warning (alarms) of potential loss of supply in the event of equipment malfunction or third party damage.
- Provide real time data to assist in producing optimum network augmentation designs including pressure control facilities.
- Improve safety for operational staff by reducing the need for operators to work in a confined space environment for assets located in underground pits.
- Provide for real time and optimum network pressure control, which will assist in minimising unaccounted for gas losses.
- More cost effective and responsive monitoring by eliminating the need to undertake periodic data logging at fringe points and manual processing of this data.
- Provision for future implementation of real time network pressure control to enable operating the network at minimum pressures, which will assist in minimising unaccounted for gas losses AGN has instituted pressure control within its metropolitan networks for a number of years, and this assists with management of network incidents and has a major benefit in minimising unaccounted for gas by being able to optimise network pressures depending on season and

[3] The Code has been developed by the Victorian Essential Services Commission and applies to all distributors that hold a distribution licence. The Code sets out the minimum standards for the operation and use of the distribution system, which include, amongst other things, minimum standards for connections and augmentations. As stated in the notes to section 3 of the Code, clause 4 of AGN's Gas Distribution Licence requires compliance with this Code.

[4] Schedule 1 Part A of the Code.

demand conditions. Refer to Appendix C for a discussion of the Mt Martha incident and how pressure control would have assisted.

1.3.1. Continuation Project

An equivalent project was previously proposed and approved by AER in the current AA period,[5] which related to the installation of SCADA equipment at 57 sites in regional areas of the Victorian and Albury networks. To date, SCADA equipment has been installed at 33 sites and another 13 sites are expected to be complete by the end of the current AA period, resulting in an estimated 46 sites being completed by December 2017, rather than the 57 that were originally proposed.

Some of the factors that have contributed to AGN being unable to complete all of the sites are set out below:

- Extended time periods from councils to obtain the required approvals for the installation. (For example, three sites in Shepparton took 2 years for local government and other utility approvals to be obtained).
- The upgrade of AGN's SCADA hardware from CITECT to Clear SCADA which required allocation of all E&I field resources to this major project to update Remote Terminal Unit (RTU) code and install it at each SCADA site.

Of the 30 planned installations in the upcoming AA period, 11 are therefore expected to be carried over from the current AA period.

1.4. Risk Assessment

A risk assessment has been carried out using APA's established evaluation criteria (detailed in Appendix A – Risk Assessment) to produce an estimated level of risk, which is summarised in Table 1.3. As this table shows, the untreated risk associated with sites that do not have remote SCADA monitoring has been assessed as "High".

Table 1.3: Risk Rating

Risk Area	Untreated Risk Level
Health and Safety	High
Environment	n/a
Operational	Moderate
Customers	Moderate
Reputation	Moderate
Compliance	High
Financial	Low
Untreated Risk Rating	**High**

If SCADA capability is not developed in regional areas then AGN may be unable to:

[5] Business Case VA02

- respond in a timely manner to emergencies resulting in future supply interruptions;
- monitor pressure on a real time basis to maintain; and
- improve safety of services and integrity of services:
  - Ongoing connections to a network creates the risk of transient[6] gas outages, with increasing frequency year on year. These outages will not be evenly distributed across the network but instead will manifest at the fringe of the network. There is the potential for an outage to result in release of uncombusted natural gas from a burner, leading to accumulation in a confined space, followed by fire, explosion or asphyxiation. In extreme cases the result could be the loss of several lives.
  - The most likely outcome is for a transient gas outage to result in non-functioning appliances, including hot water, general heating and cooking. This will likely lead to Guaranteed Service Level (GSL[7]) payments, complaints, adverse public comments, reduced reputation of AGN and potentially lead to ombudsman complaints and potentially litigation, which is why the operational, customer and reputation related risks are considered moderate.
  - Failure to use all reasonable endeavours to "…*ensure the minimum pressure is maintained at the distribution supply point*" would also result in non-compliance with the Victorian Gas Distribution System Code, which is why the compliance related risk is considered high.
  - The risk assessment has been completed on the basis of less than 100 customers being affected by a transient gas outage. Depending on the network and circumstances this could be a conservative assessment.

1.5. Options Considered

AGN has identified the following options to address the safety related risks outlined in section 1.3:

- Option 1: Do nothing; or
- Option 2: Continue to install SCADA at Field Regulators and network fringe points that currently do not have SCADA monitoring capability.

An option to complete all 63 sites in the next AA was also considered. Deliverability of this solution was considered to be problematic, as this would require doubling the number of sites installed per year over the previous Access Arrangement period, a significant step change. This option was not considered further.

1.5.1 Option 1 – Do Nothing

Under this option, AGN will continue its existing program of monitoring network pressures at the 63 sites using three or six monthly routine maintenance activities at Field Regulators and installation of temporary data loggers at network fringe points when a poor pressure problem is

6 The term 'transient gas outage' is used in this context to refer to the situation where tariff V gas demand outstrips the network's supply capability for a relatively short period of time. This could occur on a gas day if peak demand is too large and the pressure at the end of the network drops to such a low level that customers in the area of low pressure experience an interruption in supply. Once the peak load starts to fall, the network pressures will start to recover and the supply of gas will return to these customers.

7 The Guaranteed Service Level (GSL) payment is intended to ensure that customers are compensated if an energy distribution company does not meet certain minimum performance standards. The amount payable and the conditions under which a GSL payment is triggered are set out in Part E of the Code. For supply interruptions, repeated or lengthy interruptions would incur a GSL of between $150 and $300 per affected customer. Refer ESC website for a copy of the Code: http://www.esc.vic.gov.au/document/energy/26123-gas-distribution-system-code-2/

identified. This approach at fringe points is a reactive program that does not provide real time notification of when pressures fall below minimum levels.

The only benefit of this option is that there are no upfront capital costs. This option is not, however, costless or riskless because AGN will continue to incur the face the following costs and risks:

- Ongoing operational costs by means of a reactive program of installing temporary data loggers at network fringe points when customer complaints are received.
- Processing of data logger data into electronic systems, and reactive augmentation planning to provide quick-fix solutions.
- Supply outages or restrictions to groups of consumers resulting from unidentified areas where pressures are below the minimum.
- AGN's ability to efficiently plan and complete augmentation projects in a timely manner will also be limited.

The financial consequences and interruption to customers for AGN for not addressing the risks could be significant. In the event that interruptions to supply occur, depending on the circumstances and duration of interruption AGN may be required to make a Guaranteed Service Level (GSL) payment to each affected customer. Additionally, relight costs of between $40 and $70 per customer (depending on location) would be incurred.

There is also the risk of not complying with the obligation in the Code to maintain minimum pressures at distribution supply points.

The overall risk associated with this option has been rated as High (see Appendix A).

1.5.1.1. Cost/Benefit Analysis

The only benefit of this option is that there are no upfront capital costs. This option is not, however, costless or riskless because AGN will continue to incur the face the following costs and risks:

- Ongoing operational costs by means of a reactive program of installing temporary data loggers at network fringe points when customer complaints are received.
- Processing of data logger data into electronic systems, and reactive augmentation planning to provide quick-fix solutions.
- Supply outages or restrictions to groups of consumers resulting from unidentified areas where pressures are below the minimum.
- AGN's ability to efficiently plan and complete augmentation projects in a timely manner will also be limited.

The financial consequences and interruption to customers for AGN for not addressing the risks could be significant. In the event that interruptions to supply occur, depending on the circumstances and duration of interruption AGN may be required to make a Guaranteed Service Level (GSL) payment to each affected customer. Additionally, relight costs of between $40 and $70 per customer (depending on location) would be incurred.

There is also the risk of not complying with the obligation in the Code to maintain minimum pressures at distribution supply points.

The overall risk associated with this option has been rated as High (see Appendix A).

1.5.2 Option 2 – Continue to install SCADA monitoring facilities

This option will see the program for installing SCADA monitoring facilities for sites without SCADA that was approved for the current AA period continue into the next AA period. For the next AA period installations at 30 sites over a 5 year period at a rate of 6 per annum is proposed. The criteria for selection of these sites includes:

- areas experiencing high demand growth;
- areas where augmentation may be required in the near future;
- significant area where there is no remote monitoring capability (eg large country towns); and
- network supply points where there is currently no remote monitoring capability.

The remaining 33 sites are proposed to be installed over the following AA period.

This approach will increase efficiency by eliminating the need to install data loggers on a reactive basis, and undertake reactive augmentation planning on a quick-fix basis. A rate of 6 sites per annum is consistent with the annual number installed over the last two years.

1.5.2.1 Cost/Benefit Analysis

The cost of this option is estimated to be $709.5 ($000, 2016) (or $22.2 ($000, 2016) per site for metropolitan sites and $25.1 ($000, 2016) for regional areas). Once sites are installed, an annual inspection is carried out, costing an average of $1.15 ($000, 2016) per site. This cost is anticipated to be absorbed into the routine maintenance programme already existing.

This option has the following benefits:

- Timely responses to emergencies will result from early warning (alarms) of potential loss of supply in the event of equipment malfunction or third party damage to network assets.
- The availability of real time data will assist in producing optimum network augmentation designs including pressure control facilities. It will also reduce the need for operators to work in a confined space environment for assets located in underground pits.
- The RTU that is installed as part of this project can also be utilised for the future implementation of real time network pressure control that will optimize the pressures within the network to the lowest possible levels, given real time demands, and thereby assist in minimising unaccounted for gas losses.
- Site security for remote critical sites will be enhanced by the installation of site entry alarms which can be centrally monitored and responded to as part of the SCADA capability.
- It will increase the efficiency of operations and assist AGN continue to meet its obligations (e.g. provision of minimum network pressures and Guaranteed Service Levels) under the Code.
- The residual risk associated with this option will fall from High to Moderate.

1.6. Summary of Cost/Benefit Analysis

Table 1.4: Summary of Cost/Benefit Analysis

Option	Benefits	Costs/Risks
Option 1 – Do nothing	No upfront capex costs	Continuation of existing base year opex Risks of non-compliance with the Gas Distribution Code, increased levels of poor pressures, increased loss of supply incidents and customer complaints. Less efficient network augmentation Higher exposure to safety related incidents Residual risk High.
Option 2 – Install SCADA monitoring and control facilities sites currently without SCADA	Ability to monitor the system remotely, and the ability to provide timely responses to emergencies and unplanned supply interruptions Increase efficiency of operations and assist AGN to meet its obligations for minimum network pressures and Guaranteed Service Levels as prescribed in the Gas Distribution System Code Less poor supply and loss of supply incidents. Greater efficiency and optimisation of network augmentations Continued compliance with the Code Future implementation of network pressure control Residual risk reduces from High to Low.	$709.5 ($000, 2016) over the five years of the AA Period (30 sites). Opex of $1.2 ($000, 2016) per site, absorbed into routine maintenance programme

1.7. Proposed Solution

1.7.1 What is the Proposed Solution?

The proposed solution is Option 2, which will involve the continued installation of SCADA monitoring facilities in regional areas of the Victorian and Albury networks that was approved in the current AA period. In total 30 new sites will be installed over the 5 years of the next AA period, at 6 sites per year.

1.7.2 Stakeholder Engagement

Overall, our customers told us that they value current standards of reliability and are supportive of initiatives that maintain their reliability and improve the safety of the network. The majority of participants were prepared to pay to support the maintenance of the existing level of reliability of the network, with the understanding that upgrades to meet population growth are necessary investments for the supply of gas for residents into the future.

Projects that support reliability received support from 86% of workshop participants, behind only awareness of AGN assets, ongoing mains replacement program and bushfire preparedness when ranked in order of importance.

Figure 1.1: Workshop Support of AGN's Proposed Initiatives

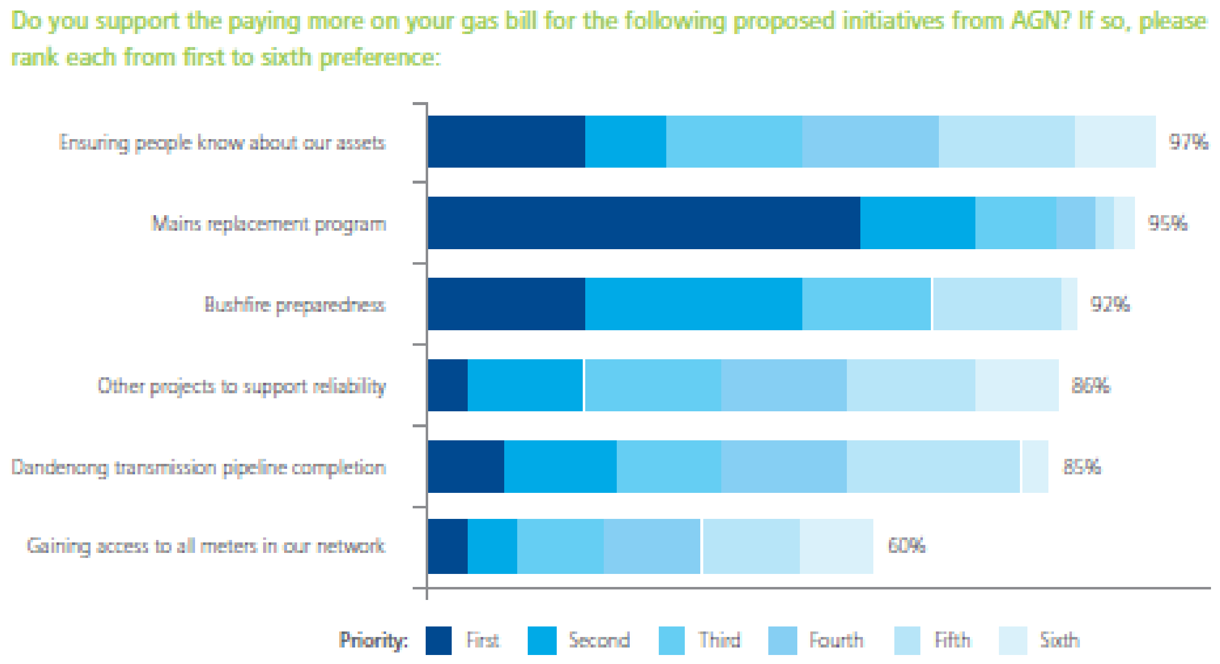


Figure 4: Total workshop support of AGN's proposed initiatives, broken down by preference rank

1.7.3 Why Are We Proposing This Solution?

The key drivers for the recommended proposal to install full SCADA facilities at 30 sites currently without SCADA are as follows:

- The expenditure is necessary to enable AGN to meet its obligations (e.g. provision of minimum network pressures) under the Code, and will provide the most efficient method of doing so (that is, avoid on-going increased operational costs (additional personnel and vehicles) to provide the same capability using existing methods).
- Timely responses to emergencies will result from early warning (alarms) of potential loss of supply in the event of equipment malfunction or third party damage to network assets. Real time system information is critical to maintaining supply as well as system integrity.
- The availability of real time data will assist in producing optimum network augmentation designs including pressure control facilities. Augmentation projects can be better planned and scheduled using up to date and accurate data, and it is anticipated that more efficient use of augmentation capital will result.
- It will eliminate the costs of installing pressure recorders and the resultant processing of the data, and increase safety by reducing the need for operators to work in a confined space environment for assets located in underground pits.
- The RTU that is installed as part of this project can also be utilised for the future implementation of real time network pressure control that will optimize the pressures within

the network to the lowest possible levels, given real time demands, and thereby assist in minimising unaccounted for gas losses.

- Site security for remote critical sites will be enhanced by the installation of site entry alarms which can be centrally monitored and responded to as part of the SCADA capability.

The project is also consistent with the findings from the stakeholder engagement program in which customers indicated that they are supportive of initiatives that maintain the reliability and safety of the network.

1.7.4 Forecast Cost Breakdown

Table 1.5 below sets out the estimated project costs over the next AA period. Based on the costs incurred in the current AA period, the cost for a typical site installation in metropolitan areas is estimated to be $22.2 ($000, 2016) (see Appendix E), while in regional areas it is estimated to be $25.1 ($000, 2016). The costs are higher in regional areas because additional allowance for travel and accommodation are required.

The costs incurred in the current period reflect the use of a mix of specialised internal labour and competitively tendered contract labour resources and competitively procured materials.

Table 1.5: Project Cost Estimate ($000, 2016)

	2018	2019	2020	2021	2022	Total
Volume (metro)	1	5	5	0	4	15
Unit Cost (metro)	22.2	22.2	22.2	22.2	22.2	22.2
Volume (regional)	5	1	1	6	2	15
Unit Cost (regional)	25.1	25.1	25.1	25.1	25.1	25.1
Total	**147.7**	**136.1**	**136.1**	**150.6**	**139**	**709.5**

1.7.5 Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN considers the forecast capex for this project to be:

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN considers the forecast capex for this project to be:

- *Prudent* – The proposed expenditure is necessary to comply with regulatory obligations and assist with ensuring that the risk of gas outages (and the associated risks to human health and safety) and response to supply emergencies can occur in a timely fashion. The proposed program is a continuation of the existing program of installation of pressure monitoring equipment at fringe network sites and pressure regulating assets. This provides an enhanced opportunity for incident response, and aids the efficient use of capital by providing more accurate and complete data for input to augmentation planning.
- *Efficient* – The labour and material cost estimates for this project are based on actual costs incurred in the last two years where SCADA components have been installed, which have been

procured through competitive procurement processes and can therefore be assumed to be efficient.

- *Consistent with accepted good industry practice* –This project is consistent with the recognised industry trend in asset management of taking advantage of technology to improve visibility of asset performance. Real time pressure information provides up-to-date data which can be used to inform a variety of asset management tasks and functions, from quick response to incidents to better planning of augmentation projects.
- *Achieves the lowest sustainable cost of delivering pipeline services* – remote monitoring of pressures and electronic storage of pressure data will assist to minimise in-field costs associated with poor pressure complaints, and will allow better planning of augmentation projects.

The capital expenditure can therefore be viewed as being consistent with rule 79(1)(a) of the NGR. The proposed capex is also consistent with rule 79(1)(b), because the expenditure is necessary to:

- *maintain and improve the safety of services (rule 79(2)(c)(i))* - safety will be increased by improved response when network pressures fall below minimum levels, and by eliminating the need for operations personnel to work in confined spaces to manually change pressure recording equipment;
- *maintain the integrity of services (rule 79(2)(c)(ii))* – the ability to maintain minimum supply pressures will be enhanced by being able to monitor pressures on a real time basis. Less consumer calls or complaints of poor pressures can be anticipated; and
- *comply with a regulatory obligation or requirement (rule 79(2)(c)(iii))* - it is a requirement under the Code that 'a distributor must use all reasonable endeavors to maintain sufficient distribution system pressures to ensure the minimum pressure is maintained at the distribution supply point'. Real time pressure monitoring via SCADA is the most efficient method for AGN to continue to meet this regulatory obligation.

Appendix A Risk Assessment

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Option Risk
less than 100 customers - transient gas outage	Likelihood	*N/A*	*N/A*	*Likely*	*Likely*	*Likely*	*Likely*	*Likely*	
	Consequence	*N/A*	*N/A*	*Minor*	*Minor*	*Minor*	*Medium*	*Insignificant*	
	Risk Level	*N/A*	*N/A*	*Moderate*	*Moderate*	*Moderate*	*High*	*Low*	
Less than 100 customers - fire, explosion due to transient gas outage	Likelihood	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	
	Consequence	*Major*	*Minor*	*Minor*	*Minor*	*Medium*	*Significant*	*Minor*	
	Risk Level	*High*	*Low*	*Low*	*Low*	*Moderate*	*High*	*Low*	
Option 2 - less than 100 customers - transient gas outage	Likelihood	*N/A*	*N/A*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	
	Consequence	*N/A*	*N/A*	*Minor*	*Minor*	*Minor*	*Medium*	*Insignificant*	
	Risk Level	*N/A*	*N/A*	*Negligible*	*Negligible*	*Negligible*	*Low*	*Negligible*	
Option 2 - Less than 100 customers - fire, explosion due to transient gas outage	Likelihood	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	
	Consequence	*Major*	*Minor*	*Minor*	*Minor*	*Medium*	*Significant*	*Minor*	
	Risk Level	*Moderate*	*Negligible*	*Negligible*	*Negligible*	*Low*	*Moderate*	*Negligible*	

Appendix B Pictures of Typical SCADA Units

Appendix C Examples of Supply Incidents

1 Thomastown I&C Customer Enquiry

Commercial customer enquiry in Industrial estate. Given the location and usage profile being different to residential areas, the equipment at existing remote control sites could not provide sufficient control of the area with the increased load. A new control site was installed in the network in question, which meant that the regulators supplying the network could react to the unique load profile of the new customer and remove the need for physical mains augmentation. The reduced cost of augmentation was a saving for the customer, and it also facilitated a successful commercial connection agreement with a corresponding rise in revenue for AGN.

2 Benalla gas leak - Olivers Rd 22 Aug 2007

A gas leak on the HP system occurred and local operations staff requested the supply pressure be lowered to increase safety and facilitate repair work. The lack of SCADA fringe data meant that a conservative approach had to be taken in determining the appropriate regulator supply pressure, with estimations of network load being generated based on weather data for the area. Real time data of fringe pressures would have given certainty of the current situation on the network (current load and likely size of escape) allowing a lower system pressure to be utilised and reducing safety concerns further, and making repair work easier and safer.

3 Yarragon Gas escape – 4th Feb 2011

AGN was contacted by AEMO regarding sharp spike in Custody Transfer Meter (CTM) flow rates at site, indicative of a gas escape. Local operations confirmed there was a gas escape. The lack of a fringe pressure data meant AGN had to wait until AEMO recognised the spike in CTM flows and reacted to contact AGN. If AEMO had not seen or reacted to their data, AGN would have had to wait for a public report of the escape. A fringe pressure monitoring site would have provided early warning of the loss of pressure due to the gas escape.

4 Rosedale supply issue – 20th May 2011

The Rosedale City Gate outlet pressure dropped due to freezing water left over from a hydrostatic test of pipework on the 19th May. At the time network modelling was undertaken to determine if there would be any supply outages in the Rosedale network. However with no actual real time pressure data from the system, numerous assumptions had to be made on likely system load at the time. Live fringe point SCADA data would have confirmed what the effect of the reduced supply pressure was and would have enabled a far more accurate prediction of immediate and short term consequences. As it was, Operations staff in the area could only be given a qualified answer rather than an exact one.

5 Hull Rd Mt Martha – 22nd July 2014

An area of Mt Martha had been identified as having low pressures but not yet below minimum requirements. However the lack of fringe point pressure data meant AGN had no real time visibility. A fringe point pressure monitoring site (RTU) was placed in the area to get a more detailed overview of the performance of the area. The day after the RTU was installed the pressures fell below the 140kPa minimum requirement to 134 kPa during the morning peak.

The RTU had quickly shown that the area was worse off than predicted. The control facilities on this network then meant that adequate pressures could be maintained in the area by adjusting the regulator upper pressure limit, giving time to appropriately assess the network in this area and plan the augmentation required. The alternative would have been to wait for customer complaints and then augment in a less efficient reactionary way.

Appendix D Sites Proposed for 2018-22 AA Period

SUBURB	SITE NAME	Proposed Year	Priority	Metro or Regional
SHEPPARTON (KIALA)	SOUTHERN TOWN FRINGE	2018	1	R
BAIRNSDALE	TOWN FRINGE	2018	2	R
PAYNESVILLE	TOWN FRINGE	2018	3	R
SANDHURST OR SKYE	NTH EAST OF HALL RD	2018	4	M
WODONGA	FRINGE AROUND SOUTH WEST	2018	5	R
WODONGA	FRINGE AROUND SOUTH EAST	2018	6	R
LALOR	EAST LALOR	2019	7	M
IVANHOE	SOUTH WEST IVANHOE	2019	8	M
WARRAGUL	TOWN FRINGE	2019	9	R
PAKENHAM	NEAR CARDINIA RD, BETWEEN RAIL AND BYPASS	2019	10	M
TYABB	GERALD ST	2019	11	M
TYABB	TOWN FRINGE	2019	12	M
MONTMORENCY	SOUTH WEST FRINGE	2020	13	M
KOO WEE RUP	KOO WEE RUP TOWN FRINGE	2020	14	M
CRIB POINT	TOWN FRINGE	2020	15	M
HASTINGS	HIGH ST	2020	16	M
MOAMA	TOWN FRINGE	2020	17	R
CRANBOUNRE	WEST CRANBOURNE	2020	18	M
ALBURY	THURGOONA ST	2021	19	R
ALBURY	THURGOONA DR	2021	20	R
ALBURY	SOUTH EAST OR NORTH EAST TOWN FRINGE	2021	21	R
ALBURY	WESTERN TOWN FRINGE	2021	22	R
SHEPPARTON	NORTHERN TOWN FRINGE	2021	23	R
HEALESVILLE	TOWN FRINGE	2021	24	R
FAIRFIELD	YARRA BEND PARK RD	2022	25	M
LANGWARRIN	NORTH RD	2022	26	M
NORTH MELBOURNE	ALFRED ST	2022	27	M
LYNDHURST	ABBOTTS RD	2022	28	M
TRAFALGAR	TOWN FRINGE	2022	29	R
MORWELL	PORTERS RD (AUST CHAR)	2022	30	R

Appendix E Detailed Cost Estimate per Site

Estimated installation cost for a typical SCADA site is shown in the table below.

Item	AC Power	Solar Power	
Kingfisher CP12	[redacted]	[redacted]	
Kingfisher IO-2	[redacted]	[redacted]	
Kingfisher BA-6	[redacted]	[redacted]	
Kingfisher AI-1	[redacted]	[redacted]	
Kingfisher PS-12	[redacted]	[redacted]	
Gas Pressure Transmitter	[redacted]	[redacted]	
Gas Temperature Transmitter	[redacted]	[redacted]	
RTU Temperature Transmitter	[redacted]	[redacted]	
Slam Shut Switches	[redacted]	[redacted]	
Tube Fittings	[redacted]	[redacted]	
B&R Enclosure	[redacted]	[redacted]	
Battery Bracket 31476B	[redacted]	[redacted]	
RCD/MCB	[redacted]		
Enclosure	[redacted]		
Socket Outlet	[redacted]		
Mounting Block	[redacted]		
Solar Panel 150W		[redacted]	
Panel Mounting Bracket		[redacted]	
SS Bird guard to suit 65W PV module		[redacted]	
Morningstar 12V, 20A controller with LVD		[redacted]	
Earth Bar	[redacted]	[redacted]	

Item	AC Power	Solar Power	
Mains Power Supply Application, Approval and Connection Fee	[redacted]		[redacted]
6 Meter Pole and panel frame, including rag bolt		[redacted]	
Fuses, Terminals, Wire	[redacted]	[redacted]	
Earth Stack	[redacted]	[redacted]	
SWA Cable 10M	[redacted]	[redacted]	
Cable Glands	[redacted]	[redacted]	
Battery 120 A/hr		[redacted]	
Battery 100 A/hr	[redacted]		
Phoenix 24v PS	[redacted]		
Battery Charger	[redacted]		
Modem/Radio	[redacted]	[redacted]	
Modem Antenna, Power Supply Accessories	[redacted]	[redacted]	
Total Materials	[redacted]	[redacted]	
Labour			[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	

40% or 12 of the 30 sites planned for installation in the next AA period require solar power installations due to the unavailability of mains supply. Taking this into account, the average cost per site is estimated to be $22,200.

Once these facilities have been installed, the ongoing maintenance costs are based on an established preventative maintenance program where SCADA installations are inspected on a yearly basis, at an estimated cost of $1,150 per site.

Appendix F Cost per Site in the Current AA Period

Sites Installed to March 2016

Site Name:	Actual Cost ($)	Comments
Fitzsimmons Lane	[redacted]	[redacted]
Bomen City Gate	[redacted]	
Chagall Parade	[redacted]	
Hull Road	[redacted]	
Salerno Way	[redacted]	
Home Road	[redacted]	
Ashmore Road	[redacted]	
Nova (Traralgon City Gate)		[redacted]
Kooringal Road	[redacted]	[redacted]
Dunns Road	[redacted]	[redacted]
Redhill Road	[redacted]	[redacted]
Sackville Street	[redacted]	[redacted]
Hume Street	[redacted]	
Wheeler Street	[redacted]	[redacted]
Gilchrist Street	[redacted]	[redacted]
Archer Street	[redacted]	[redacted]
Donnybrook City Gate		[redacted]
Rex Avenue	[redacted]	
Melrose FR		[redacted]
Culcairn City Gate	[redacted]	[redacted]
Henty City Gate	[redacted]	[redacted]
Wallendbeen City Gate	[redacted]	[redacted]
Forster Street	[redacted]	[redacted]
Longwarry City Gate	[redacted]	[redacted]

Business Case – Capex V53

Water Bath Heater Outlet Temperature Monitoring

1.1. Project Approvals

Table 1.1: Project Approvals

Prepared By	Roberto Ferrari, *Manager Capital Projects*
Approved By	Andrew Foley, *General Manager Victorian Networks*

1.2. Project Overview

Table 1.2: Project Overview

Description of Issue/Project	Water bath heaters installed in city gates prevent low gas temperatures and, hence, low pipework temperatures. This, in turn, mitigates the risk of a brittle fracture of the pipework with subsequent loss of containment, city gate shutdown and loss of supply downstream of the city gate. The described scenario would normally occur during winter and could impact on a whole town with thousands of customers affected for an extended period of time, until a temporary repair is completed. The proposal aims to provide the capability of early water bath heater malfunction detection. This will allow time to assess the malfunction and, if required, mobilise maintenance personnel to site to rectify the problem before a loss of supply occurs. A similar project was approved by the AER for the current (2013-2017) Access Arrangement (AA) period at 30 city gates[1]. It is expected that all 30 facilities will be completed at the end of 2017, with 8 additional city gates now being proposed for the next AA period as a continuation of the current program of work.
Options Considered	The following options have been considered: • Option 1: Do nothing. • Option 2: Continue to add water outlet temperature remote monitoring capability to 8 city gate water bath heaters in the next AA period.
Proposed Solution	Option 2 has been selected by AGN as the preferred option because it addresses a risk with significant consequences and continues the work started in the current AA period.
Estimated Cost	The forecast capital expenditure over the next (2018-2022) AA is $52 ($000, 2016).
Consistency with the National Gas Rules (NGR)	The Water Bath Heater Outlet Temperature Monitoring project complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because: • 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)); and

[1] AER Access Arrangement Draft Decision, Envestra Ltd, 2013-17, Part 1, p. 88.

	• it is justified under 79(2)(c) as it is required to: • maintain and improve the safety of services (79(2)(c)(i)); and • maintain the integrity of services (79(2)(c)(ii))
Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is consistent with the Reliability theme as its implementation will allow AGN to continue providing a highly reliable supply of natural gas to customers by increasing the temperature monitoring capability More information detailing the results of the stakeholder engagement program is provided in Chapter 5 of the Access Arrangement Information document.

1.3. Background

Natural gas flowing through city gates experiences a significant temperature reduction at the outlet of the regulator due to the pressure reduction. This decrease in the gas temperature can cause ice buildup due to condensation and very low temperatures in the outlet steel pipework. This situation, in addition to the stresses generated by the internal pressure, can result in a brittle fracture of the pipework, the eventual shutdown of the city gate and the supply loss to all consumers connected to it. In order to prevent this scenario, water bath heaters are installed in city gates to increase the temperature of the gas.

Several city gate operational parameters are remotely monitored through the Supervisory Control and Data Acquisition (SCADA) system to detect any anomalies in the operation. The system triggers alarms when certain pre-set parameter values are reached so that the situation can be assessed and appropriate action taken.

Water bath heaters, not already fitted with water outlet temperature monitoring, only have an alarm that is triggered by the gas pilot light extinguishing. In these cases, upon receiving the alarm, System Operations Supervisors cannot monitor the temperature of the water to determine the appropriate response and timing. The required response time will vary depending on the ambient temperature, gas flow rate and pressure in the network. In addition, there are a number of faults that can go unnoticed including low water level and burner failure. These faults can only be identified by a site visit.

All water bath heaters within the AGN network are located outside metropolitan areas and this requires a supervisor to travel up to three hours to attend to an alarm. In that time the situation could deteriorate with the potential to create a major supply interruption. By continually monitoring water temperatures, alarms can be set that will provide early identification of undesirable situations where the water could be overheating and continually boiling, or have a low water level or reduction in water temperature due to burner and/or pilot failure.

Another possible scenario is the overheating of water, thus causing the water to boil. This will cause the water to evaporate so that there is no hot water remaining to prevent a temperature loss in the gas being regulated. In turn this will also cause a 'freezing' effect on the downstream side of the regulator, potentially resulting in a supply interruption impacting large numbers of customers. On the upstream side of the regulator, this could lead to extremely high temperatures with a potential for catastrophic failure of the heater and subsequently the regulator facility.

This project proposes to continue the installation of temperature transducers to monitor the heater water outlet temperature in city gates. The remote temperature monitoring assists operational staff in determining if a failure in the heater requires immediate action with mobilisation of maintenance personnel to the city gate or ongoing monitoring only.

Water outlet temperature monitoring is standard in new heaters. The retrofitting of transducers to older heaters to monitor the water temperature started in the current AA period. The AER approved a similar project that included 30 city gates. These facilities are planned to be completed by the end of 2017. This project now proposes to retrofit the transducers to the outstanding 8 heaters within AGN Victorian networks that don't have this feature and continue with the program of works initiated in 2013. The 8 city gates are located at:

- Bangalay Ave.
- Berwick City Gate.
- Euroa City Gate.
- Laurimer Park.
- Mernda (Whittlesea) City Gate.
- Rutherglen City Gate.
- Traralgon City Gate.
- Yarrawonga City Gate.

1.4. Risk Assessment

A risk assessment has been carried out using APA's established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA's established risk management and control criteria. The table below sets out the untreated risk. As this table shows, the untreated risk is 'High' because health and safety related risks are high.

The health and safety risks are high because if a city gate water bath heaters remote monitoring and alarm detection capability is not installed, a 'freezing' effect could develop on the downstream side of the regulators, potentially resulting in a pipework failure, loss of containment and supply interruption, which could affect a large numbers of customers. These risks have been assessed as High.

Table 1.3: Risk Rating

Risk Area	Untreated Risk Level
Health and Safety	High
Environment	Negligible
Operational	High
Customers	High
Reputation	High
Compliance	Moderate
Financial	Low
Untreated Risk Rating	**High**

Further detail on the risk assessment result is provided in Appendix A to the Business Case.

1.5. Options Considered

AGN has identified the following two options to address the safety and operational related risks outlined in section 1.4:

- Option 1: Do Nothing; or
- Option 2: Continue to install transducers to monitor the heater water outlet temperatures.

1.5.1. Option 1 – Do Nothing

The first option AGN has identified is to do nothing. If this option is adopted, the ongoing program to retrofit the temperature transducers to monitor the water outlet temperatures will be interrupted and 8 city gates will be exposed to potential catastrophic failures due to malfunction in the water bath heaters.

1.5.1.1. Cost/Benefit Analysis

The benefit of this option is that it does not give rise to any upfront costs. However, the risk of a supply interruption for a large period of time and to a large number of customers due to malfunction of a water bath heater will remain. The risks associated with this option are therefore High (see Appendix A).

1.5.2. Option 2 – Install transducers to monitor the heater water outlet temperatures

The second option AGN has identified is to complete the program of work started in the current AA period, which has involved installing transducers in city gate water bath heaters to remotely monitor water outlet temperatures through the SCADA system. By doing this, operational staff will be alerted if the water temperature increases or decreases in a city gate heater, indicating that a malfunction with the potential for a significant consequence could be occurring and allowing for a prompt response.

The outstanding city gates without this technology within AGN's Victorian networks are 8. It is proposed to complete the installation of temperature transducers in all of these facilities in the next AA period. This volume of work is lower to the one that is forecasted to be completed this AA period.

1.5.2.1. Cost/Benefit Analysis

The main benefit of adding remote monitoring and alarm detection capability of heater water outlet temperatures in city gates is the early detection of potential heater malfunctions that could cause a 'freezing' effect and, ultimately, a catastrophic failure with loss of supply to a large number of customers. The monitoring of the water outlet temperatures would provide additional time to System Operations Supervisors to determine the appropriate remedial action and mobilise maintenance staff to the city gate, if required, when compared to the current gas temperature monitoring only. Also, it will alert operational personnel of other potential failures that are not currently monitored in water bath heaters including low water level and burner failure.

The cost of the project has been estimated at $52 ($000, 2016) during the next AA period.

1.6. Summary of Cost/Benefit Analysis

Table 1.4: Summary of Cost/Benefit Analysis

Option	Benefits	Costs/Risks
Option 1	No upfront capital expenditure.	Potential for undetected heater malfunction until gas temperature decreases significantly and causes a brittle fracture in the pipework with subsequent loss of containment, shutdown of the city gate and loss of supply to a large number of consumers.
Option 2	Provides early malfunction alert capability to city gate heaters, allowing prompt remedial action by maintenance staff.	Capital expenditure of $52 ($000, 2016).

1.7. Proposed Solution

1.7.1. What is the Proposed Solution?

AGN proposes to continue with the current program of work started in the current AA period, which will involve adding remote monitoring and alarm detection capability of heater water outlet temperatures to the remaining 8 city gates.

1.7.2. Why are we Proposing this Solution?

Option 2 is being proposed because it will mitigate the risk that a 'freezing' effect on downstream side of the regulators will not be detected and result in a pipework failure, loss of containment and supply interruption. The loss of supply to an entire town with a large number of customers, for a period of time that could extend for several days until a repair is carried out, constitutes a scenario that can be avoided with proven technology that has been implemented as a standard for new installations and retrofitted to older ones. In addition, this proposal would mitigate the risk of a loss of containment that could cause an explosion and fire and imply complex and lengthy repairs. Furthermore, the installation of the temperature transducers and their connection to the SCADA system is relatively simple considering the current infrastructure and could be executed, mostly, with existing internal resources.

Finally, it is worth noting that the option is consistent with the feedback AGN received through its stakeholder engagement program. During this engagement, stakeholders noted that they valued initiatives that improve the safety, reliability and customer service of the network. Consistent with these three insights, the installation of the water bath heater outlet temperature monitors will increase safety, increase reliability and reduce the number of customers affected if an incident was to occur.

1.7.3. Forecast Cost Breakdown

The cost for this project is based on actual costs incurred for similar work carried out during the last two years. The city gates that are included in this proposal are expected to have a similar level of complexity from an execution point of view to those that have already been retrofitted with heater water outlet temperature monitoring and alarm detection capability. The costs are based on the assumption that the work will be carried out, primarily, with internal labour, similarly to the current execution of the work, which has shown that current resources will be able to deliver the upgrade to the proposed 8 facilities.

The volume of work has been determined by the number of facilities that are expected to be outstanding at the end of the current AA period. If the 8 city gates included in the project are retrofitted with the proposed solution, then all of the city gates with water bath heaters within the AGN Victorian distribution network will be monitored in a consistent way.

Table 1.5: Project Cost Estimate ($000, 2016)

	2018	2019	2020	2021	2022	Total
Volume	3	3	2	-	-	8
Unit Cost	6.5	6.5	6.5	-	-	6.5
Total	**19.6**	**19.6**	**13.0**	**-**	**-**	**52.2**

Table 1.6: Project Cost Estimate, by cost ($000, 2016)

	2018	2019	2020	2021	2022	Total
Direct Labour	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Materials	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Contracted Labour	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	**19.6**	**19.6**	**13.0**	**-**	**-**	**52.2**

1.7.4. Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the NGR, AGN considers the forecast capex for this project to be:

- *Prudent* - The expenditure is necessary to help prevent a 'freezing' effect developing on the downstream side of the regulators, potentially resulting in a catastrophic failure, loss of containment and supply interruption impacting large numbers of customers. Spending $52 ($000, 2016) to ameliorate this risk is also consistent with what a prudent service provider would be expected to incur.
- *Efficient* - The cost estimate for this project is based on actual costs for similar work that has recently been carried out where transducers have been installed, setup and connected to the SCADA system. In these cases, the contractor and material costs were obtained through competitive procurement processes. The estimate can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.
- *Consistent with accepted good industry practice* - Addressing risks which pose threats to security of supply is good industry practice; in addition, the proposed solution has become a standard in new installations of this type.
- *Achieves the lowest sustainable cost of delivering pipeline services* - Installing the water bath heater outlet temperature monitors will result in a lower sustainable cost of delivering pipeline services over the longer term because it is the most cost effective way to reduce the risk and achieves a reasonable balance between residual risk and cost.

The capex can therefore be viewed as being consistent with rule 79(1)(a) of the NGR. The proposed capex is also consistent with rule 79(1)(b), because the expenditure is necessary to:

- *maintain and improve the safety of services (rule 79(2)(c)(i))* – installing temperature monitoring to water bath heaters will reduce the risk of failures and associated catastrophic consequences by providing an early detection capability to the affected facilities; and
- *maintain the integrity of services (rule 79(2)(c)(ii))* – the installation of temperature transducer with remote monitoring capability will also alert operational staff about malfunctions that could impact the gas supply to several thousands of consumers if they are not promptly addressed.

Appendix A Risk Assessment

This section includes Risk Assessments for the Untreated Risk, and for all options listed in the Options Considered section.

The Total Option Risk is the highest risk calculated for the Consequence Categories (Health & Safety, Environment etc.)

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Option Risk
Risk Untreated	**Likelihood**	*Unlikely*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	**HIGH**
	Consequence	*Major*	*Insignificant*	*Significant*	*Significant*	*Significant*	*Medium*	*Minor*	
	Risk Level	*High*	*Negligible*	*High*	*High*	*High*	*Moderate*	*Low*	
Residual Risk Option 1	**Likelihood**	*Rare*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	**MODERATE**
	Consequence	*Major*	*Insignificant*	*Significant*	*Significant*	*Significant*	*Medium*	*Minor*	
	Risk Level	*Moderate*	*Negligible*	*Moderate*	*Moderate*	*Moderate*	*Moderate*	*Low*	

Appendix B Detailed Cost Breakdown

The following is a breakdown of the costs for each city gate installation. The costs have been based on actual costs for work of the same type.

Direct labour	Qty	Rate	Amount
E&I Technician	[redacted]	[redacted]	[redacted]
Travel, accommodation and allowances	[redacted]	[redacted]	[redacted]
Supervision and project coordination	[redacted]	[redacted]	[redacted]
Subtotal - Direct labour			[redacted]

Materials	[redacted]	[redacted]	[redacted]
Temperature transmitters	[redacted]	[redacted]	[redacted]
Cables, glands and conduits	[redacted]	[redacted]	[redacted]
Subtotal - Materials			[redacted]

Contracted labour	[redacted]	[redacted]	[redacted]
Excavation and reinstatement	[redacted]	[redacted]	[redacted]
Subtotal - Contracted labour			[redacted]

Direct labour	[redacted]
Materials	[redacted]
Subtotal - Contracted labour	[redacted]
Total cost (per facility)	[redacted]